DIVIDER

STATE OF NORTH DAKOTA
INFORMATION TECHNOLOGY DEPARTMENT
SFN 2053 (4-2002)

PU-399-01-186
Montana-Dakota Utilities Co., a Division of MDU Re
2000 Electric Operations
Annual Report 01
Filed 4/17/2001 Closed 4/16/2001

DESCRIPTION

149 PU-399-01-186 Filed 09/20/2013 Pages: 972
Archived File - Roll No. 566
Public Service Commission

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

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

NOV 30 2001

November 30, 2001

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Case No. PU-399-01-186

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. , herewith submits an original and seven (7) copies of the attached discovery requests directed to Staff Witness King. These requests are being submitted in accordance with the agreed upon procedural schedule. Under that schedule, responses are due December 10, 2001.

To assure expedited delivery, this transmittal letter and the attached discovery requests have been sent to Mr. King and to Mr. Diller via email.

Please send one copy of the responses to my attention at the above address and also provide one copy to:

Mr. Steven Gaske
H. Zinder and Associates
7720 Wisconsin Ave. Suite B-102
Bethesda, MD 20814

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

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Cc: D. Schulz
W. Pearce

North Dakota Public Service Commission
Case No. PU-399-01-186
Montana-Dakota Utilities Co.
Data Requests to Staff Witness Charles W. King
November 30, 2001

1. Please provide copies of all workpapers used to prepare Mr. King's testimony.

2. Please provide copies of all testimony on rate of return, capital structure and cost of debt filed by Mr. King in any regulatory or other legal proceeding since 1991.

3. Please provide copies of all testimony on rate base filed by Mr. King in any regulatory or other legal proceeding since 1991.

4. Please provide copies of all testimony related to corporate financing and capital markets filed by Mr. King in any regulatory or other proceeding.

5. Reference: Page 12, lines 2-9 and Schedule 3:

   a. Provide copies of the relevant pages from source documents used in preparing Schedule 3.

   b. Provide copies of all workpapers, calculations and analyses used in preparing Schedule 3.

6. Reference: Page 14, footnote 6:

   a. Provide a complete copy of the FCC Notice cited.

   b. Provide complete copies of any subsequent Orders or Decisions in the cited FCC Docket.

7. Reference: Page 15, lines 17-20:

   Provide copies of all source documents, notes and other materials that form the basis for the conclusion that Zack's is a "... broader survey of investment analysts ..." than IBES.

8. Reference: Page 16, Table 4 and Pages 1 and 2 of Schedule 3:

   Provide source copies of all Zack's data in Mr. King's possession regarding growth rates for the companies shown on Table 4 and for any of the other companies shown on pages 1 and 2 of Schedule 3.

9. Reference: Page 16, Table 4; Pages 1 and 2 of Schedule 3; and Page 15, lines 17-20:

   Provide source copies of all IBES data in Mr. King's possession regarding growth rates for the companies shown on Table 4 and for any of the other companies shown on pages 1 and 2 of Schedule 3.

10. Reference: Page 18, Table 6 and Pages 1 and 2 of Schedule 3:

    Provide copies of the source materials and worksheets used to calculate the dividends, prices, and yields for the companies shown on Table 6 and for any of the other companies shown on pages 1 and 2 of Schedule 3.

11. Reference: Page 19, lines 22-23:

    Provide copies of all treatises, articles, studies and analyses that Mr. King is aware of that support the contention that the "book value growth model does not apply" to unregulated entities.

12. Reference: Page 20, Table 8 and Pages 1 and 2 of Schedule 3:

    Provide copies of all source data and calculations regarding historical growth rates for the companies shown on Table 8 and for any of the other companies shown on pages 1 and 2 of Schedule 3.

13. Reference: Page 23, lines 17-22 and Schedule 4:

    Provide copies of the relevant pages and all source data and calculations used to prepare Schedule 4.

STATE OF NORTH DAKOTA IN DISTRICT COURT

COUNTY OF BURLEIGH SOUTH CENTRAL JUDICIAL DISTRICT

NOTICE TO CLAIM EXHIBITS/DISCOVERY MATERIALS

RECEIVED
NOV - 4 2003
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
SECRETARY

DATE: October 31, 2003

TO: Douglas Bahr

RE: Montana-Dakota Utilities Co.

vs. FILE #: 02 C 1719

North Dakota Public Service Commission

Please take notice you are required to claim all:

_____ Exhibits filed by you in the above entitled action which are too large for convenient filing.

_____ Discovery materials filed by you in the above entitled action.

__x___Certificate of Records filed by you in the above entitled action.

If these items are not claimed within sixty (60) days of the date of the mailing of this notice, they will be disposed of by the Clerk of Court upon the Court's own motion and order.

In order to claim an exhibit or discovery materials, you are required to take possession at the Office of the Clerk of Court.

Debra Simenson

Clerk of Court
Burleigh County, North Dakota

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Certified record picked up from Clerk of Court
by Public Service Commission

11/04/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **1st day of August, 2003**, e-mailed the following:

Update of Margins through June 2003 requested by Commissioner Wefald

The envelope was addressed as follows:

Don Ball
don.ball@mdu.com

Charlie King
charlieking@snavely-king.com

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **1st day of August, 2003**.

Sandra L Scott
Notary Public

SEAL

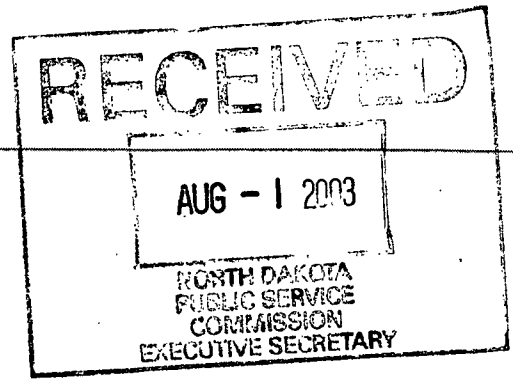
SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

147 **PU-399-01-186** Pages: 1

Affidavit of Service

by Public Service Commission

08/04/2003 CC: Comm Legal Illona, Pat, Jerry Mike .



Scott, Sandi L.

From: Diller, Michael R.
Sent: Friday, August 01, 2003 9:39 AM
To: Comm; Cramer, Kevin; Legal; PUD
Cc: Don Ball (E-mail); Charlie King (E-mail)
Subject: 2003 Case - Off System Sales Margins Summary

Attached is an update of margins requested by Commissioner Wefald through June, 2003. The overall margins were down during April, May and June of 2003 because of maintenance outages on Coyote and Big Stone but have since rebounded above company expectations.

Note to Sandi: Please docket the email and the attached schedule in case management.

Note to Sharon: Please prepare an affidavit of service for this email.

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2003 Case - Off System Sales Margins Summary
by Public Service Commission

08/01/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

Montana-Dakota Utilities Co.
Case No. PU-399-01-186
Sales for Resale Statistics
(000's Omitted)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
1996:									
kWh Sales for Resale	43,099	47,089	68,998	34,198	9,584	30,410	25,890	18,244	12,014
Revenues	$669	$716	$1,075	$492	$138	$546	$464	$342	$251
Fuel Cost	481	498	756	379	103	358	307	231	168
Margin	$188	$218	$319	$113	$35	$188	$157	$111	$83
Margin %	28%	30%	30%	23%	25%	34%	34%	32%	33%
1997:									
kWh Sales for Resale	33,549	47,963	33,383	1,802	9,395	34,576	33,514	6,564	30,534
Revenues	$668	$850	$571	$41	$149	$569	$865	$170	$525
Fuel Cost	452	520	375	28	106	417	572	112	376
Margin	$216	$330	$196	$13	$43	$152	$293	$58	$149
Margin %	32%	39%	34%	32%	29%	27%	34%	34%	28%
1998:									
kWh Sales for Resale	40,758	41,158	47,459	69,442	53,699	57,016	50,459	35,733	26,004
Revenues	$714	$754	$835	$1,118	$1,201	$1,245	$1,210	$840	$550
Demand/Other Revenue						17	0	0	0
Fuel Cost	428	426	553	725	699	655	690	531	361
Margin	$286	$328	$282	$393	$502	$607	$520	$309	$189
Margin %	40%	44%	34%	35%	42%	48%	43%	37%	34%
1999:									
kWh Sales for Resale	80,306	78,158	110,119	92,440	87,283	68,950	66,689	61,203	59,340
Revenues	$1,633	$1,536	$2,071	$1,832	$1,657	$1,817	$2,116	$1,820	$1,106
Demand/Other Revenue	-	-	-		45	45	45	45	45
Fuel Cost	968	875	1,150	1,019	952	1,026	1,209	882	642
Margin	$665	$661	$921	$813	$750	$836	$952	$983	$509
Margin %	41%	43%	44%	44%	44%	45%	44%	53%	44%
2000:									
kWh Sales for Resale	75,705	96,623	84,450	54,665	59,467	87,269	55,742	66,350	100,316
Revenues	$1,675	$1,906	$1,640	$997	$1,201	$2,477	$1,788	$2,235	$2,100
Demand/Other Revenue	0	0	0	0	0	240	120	120	120
Demand/Other Cost	0	0	0	0	0	107	53	53	53
Fuel Cost	1,204	1,086	920	618	606	1,306	1,262	1,124	1,135
Margin	$471	$820	$720	$379	$595	$1,304	$593	$1,178	$1,032
Margin %	28%	43%	44%	38%	50%	48%	31%	50%	46%
2001									
kWh Sales for Resale	83,940	85,313	98,385	82,021	50,891	47,452	59,469	67,521	74,006
Revenues	$2,336	$2,212	$2,679	$2,274	$1,345	$2,089	$3,582	$4,085	$1,437
Demand/Other Revenue	33	33	33	34	-				
Demand/Other Cost	-	-	-	-	-			280	
Insurance Recovery	-	918	-	(179)	72				
Fuel Cost	1,020	967	1,114	939	886	692	942	1,115	793
Margin	$1,349	$2,196	$1,598	$1,190	$531	$1,397	$2,640	$2,690	$644
Margin %	57%	98%	59%	52%	39%	67%	74%	66%	45%
2002									
kWh Sales for Resale	92,964	58,020	75,613	70,366	68,254	61,172	46,205	69,905	37,476
Revenues	$1,644	$996	$1,446	$1,471	$1,294	$1,052	$1,110	$1,338	$699
Fuel Cost	$1,022	$621	$826	$742	$753	$729	$613	$805	$536
Margin	$622	$375	$620	$729	$541	$323	$497	$533	$163
Margin %	38%	38%	43%	50%	42%	31%	45%	40%	23%
2003									
kWh Sales for Resale	86,863	72,673	91,855	23,269	44,802	54,855			
Revenues	$ 2,239	$ 2,194	$2,569	$544	$1,048	$1,561			
Fuel Cost	1,151	1,025	1,201	332	575	729			

Margin	$1,088	$1,169	$1,368	$212	$473	$832
Margin %	49%	53%	53%	39%	45%	53%

Montana-Dakota Utilities Co
Case No. PU-399-01-186
Sales for Resale Statistics
(000's Omitted)

Description	Oct	Nov	Dec	Total
1996:				
kWh Sales for Resale	4,501	31,738	48,770	374,535
Revenues	$90	$609	$861	$6,253
Fuel Cost	64	421	572	4,338
Margin	$26	$188	$289	$1,915
Margin %	29%	31%	34%	31%
1997:				
kWh Sales for Resale	29,219	42,451	59,004	361,954
Revenues	$549	$921	$1,146	$7,024
Fuel Cost	380	522	672	4,532
Margin	$169	$399	$474	$2,492
Margin %	31%	43%	41%	35%
1998:				
kWh Sales for Resale	21,977	66,180	76,655	586,540
Revenues	$439	$1,368	$1,585	$11,859
Demand/Other Revenue	0	0	0	17
Fuel Cost	267	857	868	7,060
Margin	$172	$511	$717	$4,816
Margin %	39%	37%	45%	41%
1999:				
kWh Sales for Resale	72,200	83,644	83,189	943,521
Revenues	$1,172	$1,488	$1,458	$19,706
Demand/Other Revenue	45			270
Fuel Cost	678	934	868	11,203
Margin	$539	$554	$590	$8,773
Margin %	44%	37%	40%	44%
2000:				
kWh Sales for Resale	112,189	66,611	70,931	930,318
Revenues	$2,199	$1,794	$1,826	$21,838
Demand/Other Revenue	120	33	34	787
Demand/Other Cost	54	0	0	320
Fuel Cost	1,323	863	940	12,387
Margin	$942	$964	$920	$9,918
Margin %	41%	53%	49%	44%
2001				
kWh Sales for Resale	80,514	80,066	88,600	898,178
Revenues	$1,576	$1,530	$1,607	$26,752
Demand/Other Revenue				133
Demand/Other Cost			178	458
Insurance Recovery				811
Fuel Cost	984	891	957	11,300
Margin	$592	$639	$472	$15,938
Margin %	38%	42%	29%	59%
2002				
kWh Sales for Resale	32,582	92,868	79,105	784,530
Revenues	$661	$1,900	$1,752	$15,363
Fuel Cost	$476	$1,207	$1,050	$9,380
Margin	$185	$693	$702	$5,983
Margin %	28%	36%	40%	39%
2003				
kWh Sales for Resale				374,317
Revenues				$10,155
Fuel Cost				$5,013

Margin	$5,142
Margin %	51%

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000-Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **16th day of January, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed, each containing a photocopy of:

Order on Remand

The envelopes were addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0001 2975 2839

William P Pearce
P O Box 400
Bismarck ND 58502-0400
Cert. No. 7001 2510 0001 2975 2822

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0001 2975 2815

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **16th day of January, 2003**.

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

Notary Public

145 **PU-399-01-186** Pages: 2
Affidavits of Service
by Public Service Commission
01/16/2003 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **16th day of January, 2003**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, or sent by electronic mail, each containing a photocopy of:

Order on Remand

The envelopes and electronic mail were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **16th day of January, 2003**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

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Brad Schmidt
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State Capitol
Bismarck ND 58505

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Bismarck ND 58501

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Dakota Resource Council
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Denver CO 80202-4167

KMAV AM/FM RADIO
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Mayville ND 58257-0216

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Montana-Dakota Utilities Co
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Bismarck ND 58501

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Dennis Lavallee
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Kim Christianson
ND Department of Commerce
Division of Community Services
Bismarck ND

John Kapsner
The Vogel Law Firm
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Bismarck ND 58502-2097

Steven Tomac
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St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
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Elk River MN 55330-0800

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Oklahoma City OK 73102-7101

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KHND AM Radio
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Harvey ND 58341-0006

Michel Murray
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Denver CO 80202

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Bismarck ND 58501

Robert Burns
National Regulatory Research Inst
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Columbus OH 43210

Scott Speaker
Natural Gas Week
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Washington DC 20005-2150

Public Utilities Reports Inc
Law Dept
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Vienna VA 22182

LeRoy Neubauer
Valley City Public Works
254 2nd Ave NE
Valley City ND 58072

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

APPROVED

DATE: 1/15-03

KMF

MOTION

January 15, 2003

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission adopt the Order on Remand in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

Sdh

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Motion

by Public Service Commission

01/15/2003 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

ORDER ON REMAND

January 15, 2003

On April 24, 2002 the Public Service Commission issued its Findings of Fact, Conclusions of Law and Order in this proceeding.

The decision was appealed by Montana Dakota Utilities Company on one issue, the projected level of wholesale margins. The Commission incorporated into its rate reduction requirement an annual system wide projected level of wholesale margins of $11.696 million for the test year. MDU asserted that the Commission's projections were far too high and that the test year should include only $6.43 million in system wide projected wholesale margins. North Dakota's share of this difference is the basis for the amount at issue in the appeal, $3.475 million annually.

On May 2, 2002, the District court ordered that the portion of the Commission order at issue on appeal directing a reduction in MDU's electric retail rates in the amount of $3.475 million be stayed pending further order of the Court. The court further ordered that MDU file a suspending bond in the amount of $3.475 million and establish an interest bearing escrow account for deposit of the revenues MDU would collect in excess of the rates it would have charged were the Commission's order not stayed.

Also on May 2, 2002, MDU filed tariff revisions effective for service rendered on or after May 8, 2002 and reflecting the Commission's decision as modified by the District Court's order for a stay.

On November 22, 2002, the District court issued an order reversing the Commission decision on this issue and remanding the case back to the Commission with direction that the Commission adequately explain the basis for including projected system wide wholesale margins of $11.696 million, or in the alternative, adopt MDU's $6.43 million projected system wide wholesale margins for the test year.

Order

The Commission orders:

1. Test year revenue projections shall include projected system wide wholesale margins of $6.43 million rather than $11.696 million.

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Order on Remand
by Public Service Commission
01/15/2003 CC: Comm Legal Illona, Pat, Jerry Mike

2. MDU is entitled to charge rates in North Dakota sufficient to recover the North Dakota portion of the difference between system wide projected wholesale margins of $11.694 million and $6.43 million.

3. MDU is entitled to charge rates in North Dakota sufficient to recover the $3.475 million at issue in this proceeding. Since this portion of the Commission's original order was stayed, these rates are currently in effect and no rate change is necessary to incorporate this decision.

PUBLIC SERVICE COMMISSION

Anthony T. Clark	**Susan E. Wefald**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

APPROVED
DATE: 12-31-02
KMF

MOTION

December 31, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission close this portion of the meeting and go into Executive Session under N.D.C.C. §44-04-19.1(2) for the purpose of discussion with the Commission's attorney, Case No. PU-399-01-186.

IJS/sdh

142 **PU-399-01-186** Pages: 1

Motion closing protion of meeting for discussion with Commission's Attorney by Public Service Commission

12/31/2002 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA IN DISTRICT COURT

COUNTY OF BURLEIGH SOUTH CENTRAL JUDICIAL DISTRICT

RECEIVED
NOV 26 2002
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.,

Appellant,

v.

North Dakota Public Service Commission,

Appellee.

MEMORANDUM OPINION

02-C-1719

PU-399-01-186

The appellant, an investor-owned utility, has appealed the decision of the Public Service Commission issued on April 24, 2002, which ordered an across-the-board reduction of electrical rates for North Dakota customers in the amount of $4.273 million annually.

The proceeding was initiated by the Public Service Commission based on its determination that Montana Dakota Utilities (MDU) was receiving net revenues in excess of the sums necessary to earn a reasonable return on investment. The complaint, filed by the Public Service commission (PSC) staff sought a reduction in retail electric rates in an amount of $9.155 million annually. The expansive proceeding before the PSC entailed various issues related to the income and expenses of the utility. The focus of this appeal is the PSC determination that the re-sale sales (wholesale sales to other utilities) by the appellant justified the rate reduction which has been ordered.

MDU seeks review of the PSC order on grounds that its findings of fact do not conform to the evidence contained in the record, and that, accordingly, the conclusion of law that MDU's existing electric rates yield excess revenues of $4.273 million per year is erroneous.

The extensive record consists of a 499 page transcript of hearings conducted before an administrative law judge on February 25 and 26, 2002, and 118 separate documentary

exhibits, including extensive written expert testimony.

This appeal is based on the appellant seeking review of the findings of fact numbers 29 through 40, and conclusion of law number 3, which deal with the PSC's determination regarding MDU's revenues from wholesale electricity to other entities.

The proceedings in this court are governed by Chapter 28-32 of the N.D.C.C., the Administrative Agencies Practice Act. The review is limited to the record on appeal, and the Court is required to affirm the determination of the PSC unless it finds that the provisions of N.D.C.C. § 28-32-46 have not been complied with. Historically, this section of the Code has required affirmation of an agency's decision if the order complies with the law, does not violate the due process or constitutional rights of the appellant, and the findings of fact and conclusions of law are supported by the record.

The 2001 Legislature added additional requirements to the scope of review, one of which is pertinent in this proceeding: "The Court must affirm the order of the agency unless it finds [7. The findings of fact made by the agency do not sufficiently address the evidence presented to the agency by the appellant.]"

The heart of this proceeding deals with the determination regarding a "test year" for the establishment of utilities rates in accordance with N.D.C.C. §49-05-04.1. The year 2002 was designated as the "test year," and the dispute between the parties centers around the manner in which the projected revenues for the test year were determined. The PSC adopted the recommendations of its staff in projecting wholesale margins to the 2002 test year based on a three year historical average (1999, 2000, and 2001). MDU asserts that the manner in which the projection was arrived at is not supported by evidence presented in the course of the proceeding.

The parties agree that MDU had realized increasing margins through wholesale sales of electricity in recent years, as reflected by the following:

YEAR	Wholesale Margins
1996	$ 1,915,866
1997	$ 2,491,993
1998	$ 4,816,728
1999	$ 8,772,849
2000	$ 9,918,345
2001	$15,937,892

In reliance on the testimony of witnesses called by the PSC counsel, Mike Diller and Charles W. King, the Commission determined that adopting a three year historical average based on the wholesale sales in 1999, 2000, and 2001 was the reasonable manner in which to arrive at a projection for the test year. Utilizing this formula and making adjustments for demand penalties, the Commission arrived at a projected wholesale margin of $11.696 million for the test year. This level became the basis for the reduction in retail rates ordered in the amount of $4.273 million annually.

The appellant has argued strenuously that the wholesale margins in the three years utilized for arriving at the average represent a period of abnormally high revenues and do not fairly represent the income picture that can be anticipated from wholesale sales in the test year and subsequent years. Experts called to testify on behalf of MDU presented extensive testimony in support of the conclusion that the three years in question were anomalies, both from the standpoint of the pricing of wholesale electricity, as well as the volume sought by wholesale customers. As an alternative to the three year historical average, MDU proposed a projected net revenue from wholesale sales in the amount of $6.43 million based on a variety of factors, including projections of reduced prices based on the futures market, as well as lowering demand or decreased market. Consistent with MDU's contention was a supplement to the record in the form of testimony by MDU's electric bulk power marketing

coordinator, Terry L. Blinsky, indicating that wholesale sales income to the utility in the first quarter of 2002 was $1,618,840 compared to $4,126,072 for the first quarter of 2001. A decline in sales was also reflected, showing actual sales in the first quarter of 2001 in the amount of 260,830 Mwh (megawatt hours) compared to 226,356 Mwh in the first quarter of 2002.

ANALYSIS OF COMMISSION'S FINDINGS

The Court's role is a limited one, as indicated above. The review cannot represent the Court's independent assessment of the evidence, but rather an assessment of whether the agency findings are consistent with the evidence. The Court cannot substitute its judgment for the Commission's judgment, and should affirm the decision "if a reasoning mind could have reasonably determined that the conclusions were supported by the evidence." Sonterre v. Job Service, 379 N.W.2d 281 (N.D. 1985), Ehli v. Workmen's Compensation Bureau, 447 N.W.2d 313 (N.D. 1989), Domek v. N.D. State Personnel Board, 430 N.W. 2d 339 (N.D. 1988).

This Court will not reiterate the substantial testimony presented by the expert witnesses. The thrust of Mr. Diller's testimony was to the effect that the actual numbers represented by the three years utilized in arriving at the recommended average were actual numbers, as opposed to projections of the type relied on by the appellant in its recommendation for wholesale revenues in the test year. The testimony, which was adopted by the Commission, emphasized that a variety of 28 different factors which would affect wholesale pricing were basically outside of the control of the utility or the Commission, and thus unpredictable.

The testimony on behalf of MDU on the issue of factors to consider for the wholesale price to be attributable to the test year indicated that there were substantial anomalies which

occurred, making the revenues for 1999, 2000, and 2001 unrepresentative of what could be expected in the future.

The extensive expert testimony presented by MDU on the wholesale pricing issue came from C. Wayne Fox, MDU president; Terry L. Blinsky, marketing coordinator for MDU; J. Steven Gaske, a consultant on utility finance; Roger Shiffman, an energy consultant; and Paul Wilkenson, vice-president of policy analysis of the American Gas Association. Their testimony focused on the volatility of pricing of wholesale electricity in the three years used for the average, the high demand for wholesale electrical power during this time as a result of shutdowns of nuclear energy generating facilities, and the unusually high price of electricity brought about by shortages related to heavy consumption and increased demand due to overall economic conditions and weather conditions during a portion of the three years used for the average.

The central issue in the case becomes whether the findings 29-40 made by the Commission on this point appear to be consistent with the substantial evidentiary record. Findings numbers 29 through 39 constitute recitations of the evidence on the part of experts for both sides. Findings 37 and 38 refer to specific testimony by Dr. Gaske regarding the reliability of futures prices, and the Blinsky testimony regarding comparative earnings in the first quarters of 2001 and 2002. The remaining findings contained at 29-39 focus on the testimony of Mr. Diller regarding the reliability of actual sales reported in the years utilized for the average, versus the difficulty in predicting future pricing.

The "analysis" of the evidence by the Commission is set forth in Finding No. 40 as follows:

> 40. The Commission finds a high degree of uncertainty associated with predictions that are affected by one or more of at least 28 factors and the large number of combination of those factors that are outside MDU or Commission

control. These factors can change dramatically, as evidenced by the change in prices of natural gas in recent years. We find that using the average of sales for resale during 1999, 2000, and 2001 is the most appropriate decision at this time.

Finding No. 40 was the foundation for Conclusion of Law No. 3, which stated: "3. MDU's existing electric rates yield excess revenue of $4.273 million per year."

This Court concludes that the expansive record setting forth the pitfalls of relying on resale revenues during the three years in question is not addressed adequately in the Commission's Findings. Substantive testimony regarding the unusual combination of factors resulting in the high prices and increased demand during these three years is not reflected in the Commission's Findings. A significant part of the evidence on the issue of wholesale pricing factors to arrive at a number for the test year is not referred to in any way in the Commission's Findings.

Counsel for the appellee has focused on the broad acceptance of using historical averages. The use of historical averages is a generally acceptable manner of establishing pricing standards in the utilities area. Counsel for both sides have acknowledged this, and counsel for the Commission, in particular, has pointed out the way in which historical averages have been used in other jurisdictions, in other cases, and also in the present case, in arriving at appropriate numbers for other items under consideration.

I conclude that the concept of historical averaging to arrive at pricing is inherently sound and generally reliable to assist in the prediction of future outcomes, but it doesn't "fit right" in this context when the significant contra-indicators that the historical years predict the future have not been adequately considered by the fact finders.

While the mechanism of using historical averages in itself is acceptable, or even recommended, the Commission appears to have disregarded substantial evidence which was

put into the record in an attempt to show that utilizing these three particular years would not be reasonable or representative of the year 2002, or future years. The appellant's evidence on this point is focused on a variety of considerations to indicate these particular years cannot be seen as representative of what will occur in future years. The record does not contain evidence to indicate that future years' prices will be subject to the same influences that inflated the revenues for the historical average years. Without evidence of this type, the Commission's conclusion that these years are representative of the future is without foundation in the record. In particular, the "spiking" of prices dues to acute shortages of power ($142.50 per Mwh in December 2000, vs. $44.00 per Mwh in January 2002) are not part of the analysis in support of the Findings of the Commission, and, in fact, suggest the Findings are incomplete. The testimony of Dr. Gaske regarding the reliability of futures prices as a fair indication of expected markets is not refuted in the record, but seems to have been treated as "speculation" in the Commission's conclusions.

If the record contains reliable evidence to indicate the test years' prices can be relied upon to predict prices for 2002 and subsequent years, the Commission has not made reference to it in the Findings. Accordingly, its Findings are not supported by the evidence.

In its consideration of the record, the Commission's Findings do not comport with the requirement contained in N.D.C.C. § 28-32-46(7) that an agency's findings must "sufficiently address the evidence presented to the agency by the appellant." Also, because the Commission initiated the proceeding, it has the burden of proof, which this Court concludes it has failed to carry.

The North Dakota Supreme Court has addressed the issue of an agency's disregard of evidence favorable to the appellant in a series of Workers Compensation cases.

In Moses v. N.D. Workers Compensation Bureau, 429 N.W.2d 436 (N.D. 1988), the appellate court reversed the trial court's affirmation of a Workers Compensation decision

denying the defendant's claim based on injuries she attributed to her employment with the Burleigh County Sheriff's Department. In concluding that the Bureau had ignored the testimony of three physicians regarding the appellant's injuries, the Court cited an earlier case, Satrom v. N.D. Workers Comp. Bureau, 328 N.W.2d 824 (N.D. 1982), stating: "We believe our case law clearly indicates that in cases. . .where expert medical testimony is desirable, if not essential to a determination of causation, the Bureau may not simply ignore competent medical testimony without expressly setting forth in its Findings of Fact adequate reasons, which are supported by the record, for doing so."

In DeChandt v. N.D. Workers Compensation Bureau, 452 N.W.2d 82 (N.D. 1990), the Supreme Court again reversed a trial court decision affirming the order of the Workers Compensation Bureau denying benefits for DeChandt, who had been injured while employed as a deputy with the Ward County Sheriff's Department. In its opinion the Court stated: "Although it is within the province of the Bureau to weigh and resolve conflicting medical opinions, if there is conflicting medical evidence, the Bureau must adequately explain its reason for disregarding evidence favorable to the claimant," citing Hayden v. N.D. Workers Compensation Bureau, 447 N.W.2d 489 (N.D. 1989).

In Spangler v. N.D. Workers Comp. Bureau, 519 N.W.2d 576 (N.D. 1994), the Supreme Court analyzed the conflicting medical opinions regarding Spangler's back injury. In its admonition to the Bureau for failure to clarify the basis for accepting ceratin evidence over other evidence, the Court stated:

> We are not going to reweigh the medical evidence and conclude Dr. Draper's diagnosis is wrong and Dr. Anthony's is right. However, judges are not medical experts, so the Bureau's selective rejection of medical evidence must be adequately explained for appellate review. See Kopp v. N.D. Workers Compensation Bureau, 462 N.W.2d 135 (N.D. 1990). Like our rules of

procedure, we do not expect our "adequate explanation" requirement to be treated by the Bureau as "empty noise." See Matter of Estate of Raketti, 340 N.W.2d 894, 898 (N.D. 1983). As Justice Frankfurter discussed in Universal Camera Corp. v. Nat'l. Labor Relations Board:

> The Board's findings are entitled to respect; but they must nonetheless be set aside when the record before a court of appeals clearly precludes the Board's decision from being justified by a fair estimate of the worth of the testimony of witnesses, or its informed judgment on matters within its special competence, or both.

340 U.S. 474, 490, 72 S. Ct. 456, 466, 95 L.Ed. 456 (1951)(substantial evidence standard under Administrative Procedure Act). We too have critically examined evidence and concluded that the Bureau's decision was not supported by the greater weight of the evidence.

Referring the Bureau's failure to explain certain evidence in the record contrary to its conclusions, the Court referred to the earlier case of Matuska v. N.D. Workers Comp. Bureau, 482 N.W.2d 856 (N.D. 1992), stating:

> "An adequate explanation for the Bureau's rejection of evidence favorable to the claimant may be provided in the Bureau's analysis of why it accepted contrary evidence." Wherry, 498 N.W.2d at 141. In this case, the reasons given for relying on Dr. Draper's opinion do not adequately explain why the Bureau rejected Dr. Anthony's opinion that the 1990 myelogram showed a small herniation, Dr. Moskowitz's opinion that both myelograms were inaccurate, or Dr. Moskowitz's opinion that the 1992 herniation was a natural result of the 1990 injury.

And further:

> The Bureau is free to prove on remand, if it can, that the reoccurrence of Spangler's back pain is coincidentally located ant not causally related to his 1990 injury. t he Bureau can cross-examine Dr. Anthony about his diagnosis. t he Bureau can also ask Dr. Moskowitz whether the negative 1990 myelogram is supported by the lack of any credible complaints from Spangler until 13 months after the original injury. The Bureau may also be able to prove that the 1990 injury was not the only contributing factor to the herniation. . . .However, without an adequate explanation for disregarding the significant medical evidence supporting Spangler's claim, the Bureau's decision is not supported by a preponderance of the evidence.

In Naumann v. N.D. Workers Comp. Bureau, 545 N.W.2d 184 (N.D. 1996), the Supreme Court remanded the case back to the Workers Compensation Bureau with instructions stating: "The Bureau has not adequately resolved the conflict in the medical evidence, or explained its reason for disregarding Dr. Uthus' evidence." (Evidence which had been favorable to appellant.)

Finally, in Hoffman v. N.D. Workers Compensation Bureau, 651 N.W.2d 601 (N.D. 2002), the Supreme Court again reversed a trial court's affirmation of the Workers Compensation Bureau's denial of benefits to an injured worker. Hoffman had been deemed ineligible for benefits when he failed to comply with a rehabilitation plan established by the Bureau, and the Bureau determined that his noncompliance was without good cause. In concluding that the Bureau had failed to consider significant medical evidence in the record on the question of noncompliance, the Court stated:

> The Bureau in this case ignored evidence favorable to Hoffman. The only medical evidence in the record is from Hoffman's physician, Dr. Krause. She

recommended no more than two classes for Hoffman because he was not tolerating the amount of time it took to sit at the computer and take the courses. Her reports, combined with the testimony of the chairman of the computer office technology department at BSC about the compressed summer school schedule, indicates Hoffman was simply unable, for medical reasons, to successfully complete the summer course. Dr. Krause also said Hoffman was not unwilling, but was "unable" to complete the FCE because of his pain. Because the Bureau failed to give any explanation for its disregard of this evidence, the case must be remanded to the Bureau for reconsideration." (Emphasis added).

This case also addresses the new provision in N.D.C.C.§ 28-32-47 which requires that an agency order be affirmed "unless the Findings of Fact made by the agency do not sufficiently address the evidence presented to the agency by the appellant." While not concluding that the statute was applicable because of the enactment date, the Court made reference to its being consistent with earlier rulings of the Court admonishing administrative agencies that evidence favorable to an appellant cannot be disregarded in making findings of fact.

While involving another agency, this Court concludes that the above cases are relevant to the current case because of the principles enunciated by the Supreme Court. It is unclear from the record why the PSC disregarded the substantial record of evidence presented by the appellant, to the effect that accepting the recommendation of staff for the three year historical average of wholesale prices would not result in realistic numbers for the 2002 test year.

This series of Workers Compensation decisions stand for the principle that evidence

favorable to the appellant cannot be disregarded, or findings contrary to the evidence must be adequately explained.

As indicated earlier in this opinion, the Court is required to pay deference to the PSC, given its expertise and experience. It is not possible to say that the decision arrived at is an incorrect one, but it this Court's opinion, the decision is not adequately explained in the Findings which provided a basis for the order.

The decision of the PSC is reversed. The case is remanded back to the PSC with an order that it adequately explain the basis for its decision in its Findings, or in the alternative, adopt the $6.43 million calculation proposed by the appellant based on anticipated sales and future pricing as a reasonable 2002 test year level.

If the Commission elects to appeal, this Court will respond with appropriate orders designating this decision as a final trial court judgment in the matter.

Dated this 22nd day of November, 2002.

BY THE COURT:

Burt L. Riskedahl

Burt L. Riskedahl, District Judge
South Central Judicial District

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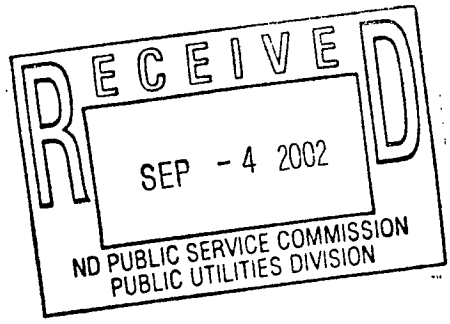
September 3, 2002



Ms. Debra Simenson, Clerk
Burleigh County District Court
514 East Thayer Avenue
Bismarck, ND 58501

Re: Montana-Dakota Utilities Co. v. North Dakota Public Service Commission
Case No. 08-02-C-01719

Dear Ms. Simenson:

Enclosed for filing in the above-referenced case is Appellant's Reply Brief and Notice of Oral Argument.

Sincerely,

Daniel S. Kuntz

Enclosure

c: Douglas Bahr
Illona Jeffcoat-Sacco

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Copy of Letter to District Court re Reply Brief and Notice of Oral Argument by Montana-Dakota Utilities Co., a Division of MDU Re

09/04/2002C: Comm Legal PUD (3) Mike AG's Office .

STATE OF NORTH DAKOTA

COUNTYOF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,	)
	) **APPELLANT'S REPLY BRIEF**
Appellant,	) **AND NOTICE OF ORAL ARGUMENT**
	)
-vs-	)
	)
North Dakota Public Service Commission,	)
	)
Appellee.	)

NOTICE

The Appellant Montana-Dakota Utilities Co. ("MDU") submits the following brief in reply to the Appellee's Brief dated August 19, 2002. Pursuant to the Court's Amended Scheduling Order, MDU requests oral argument on its appeal and has arranged for such argument to be held before the Court at 10:30 a.m. CDT on October 8, 2002 at the Burleigh County Courthouse.

ARGUMENT

The Commission has failed to show that its finding of fact that it was "most appropriate" to project wholesale margins for the 2002 test year based on a three year historical average is supported by a preponderance of the evidence.

The Public Service Commission acknowledges that it is necessary to project revenues and expenses for the test year. Application of Montana-Dakota Utilities Co., 102 N.W.2d 329, 341-342 (N.D. 1960). North Dakota law specifically allows a public utility to use a "historic," "current," or "future" test year in a proceeding to set the utility's rates. N.D.C.C. § 49-05-04.1. The statutory allowance for test year projections recognizes that historical results are inappropriate to set utility rates for the future when

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Appellant's Reply Brief and Notice of Oral Argument
by Montana-Dakota Utilities Co., a Division of MDU R
09/04/2002C: Comm Legal PUD (3) Mike AG's Office

changes have occurred to make historical results unrepresentative or unreliable. Although historical results are a starting point for all test year projections, when evidence is introduced showing that historical results are not reasonably indicative of current or expected future results, the projection of revenues and expenses for the test year must be based upon a preponderance of all the evidence. Hoffman v. North Dakota Workers Compensation Bureau, 2002 ND 138. The Public Service Commission cannot simply disregard the evidence of changed conditions. Id. Otherwise, as demonstrated in this proceeding, the utility is effectively denied the benefit of test year projections to reflect changed conditions as provided for under N.D.C.C. § 49-05-04.1.

As discussed in its appellant's brief, MDU presented extensive and uncontroverted testimony that conditions had drastically changed in the wholesale electric power market after the three year period used by Mr. Diller to calculate a historical average. While the Commission cavalierly argues that MDU speculated regarding its projected wholesale electric margins for the test year, MDU's projections were based upon recent actual results as well as known changes in the wholesale power market as testified to by experts and witnesses experienced in the sale of wholesale power. In contrast, the Commission's finding that MDU would experience wholesale electric margins during the test year equal to the three year historical average was total speculation, unsupported by any testimony, that the future would mirror the past. Indeed, the three year historical average was acknowledged as arbitrary by the Commission's only witness on the issue.

A projection based upon a historical average doesn't assure the projection is reasonable or accurate. For example, projecting the price of Enron stock based upon

its historical average price from 1999 to 2001 would be indeed foolish in light of known changed conditions. A reasoning mind does not project future revenues or expenses based upon historical levels in the face of uncontroverted evidence that the factors that influenced those revenues and expenses have drastically changed.

Although the Commission argues that Mr. Diller identified a number of factors that can influence wholesale electric margins, there was no testimony that any of those factors were expected to offset the effect of the known changed factors that led to recent drastic declines in wholesale electric margins. The Commission's use of historical averages assumes, notwithstanding recent changes in the factors, that the factors would nonetheless influence the margins in 2002 in the same way they influenced the margins in 1999-2001. In this case there is no evidence to support that assumption. Merely because MDU and the Commission have no control over the factors doesn't mean the factors didn't change from the 1999-2001 period. Blindly following historical results without recognizing known changes in the factors was a recipe for error.

At page 7 of its brief, the Commission states: "Based on the evidence, a reasoning mind could reasonably conclude it is better to rely on known and measurable historical information, rather than subjective, unmeasureable forecasts." The forecasts offered by MDU were neither subjective nor unmeasurable. The primary difference between the MDU forecast and the historical average was the wholesale price of electricity. As discussed and cited in its Appellant's brief, MDU's witnesses used published futures prices of wholesale electricity for their projection. These are known and measurable prices used by current buyers and sellers of wholesale electricity based

upon existing and expected market conditions. In contrast, the projection of wholesale prices based upon a three year historical price was not only subjective but whimsical in the face of current market conditions.

At page 8 of its brief, the Commission continues: "It was reasonable for the Commission to use a three-year average because the wholesale margins that occurred in the most recent three years are more likely to be representative of margins to be incurred in the test year." The Commission cites no evidence from the record to support its statement – NONE. In stark contrast to the pages of uncontroverted testimony offered by several witnesses sponsored by MDU that it was unreasonable to rely upon the 1999-2001 historical results to project future wholesale electric margins, the Commission cannot point to any evidence in the record that the three year historical average of wholesale margins would more likely represent the margins that would occur in the 2002 test year. In fact, such evidence would have been contrary to the actual margins during the first quarter of 2002 as acknowledged at paragraph 38 of the Commission's Findings of Fact. The standard for reviewing a finding of fact of an administrative agency is whether a reasoning mind reasonably could have determined the agency's finding is supported by the weight of the evidence based on the entire record. Opp v. Ward County Social Services Bd., 2002 ND 45, ¶8, 640 N.W.2d 704, 708. No reasonable person could reasonably conclude, based upon the evidence of the entire record, that MDU could hope to achieve wholesale margins during the test year equal to the three year historical average used by the Commission.

In a telling admission of the lack of evidence to support its findings, the Commission relies not upon testimony or exhibits from the record to support its position

but rather upon testimony and decisions from other cases – most from other state commissions. The use of testimony, such as Attachment 1 to the Commission's brief, from another proceeding that was not introduced as evidence in this proceeding is inappropriate to support the order on appeal. N.D.C.C. §§ 28-32-44(5) and 28-32-46. Sprunk v. North Dakota Workers Compensation Bureau, 1998 ND 83, ¶7, 578 N.W.2d 861, 864 (1998). Similarly, decisions of the North Dakota Public Service Commission in prior cases, or decisions from other state commissions, cannot be used as evidence to support a finding of fact in this case. The issue before the Court is whether the Commission's finding of fact is supported by the preponderance of the evidence entered into the record of this case and not by evidence or decisions from other cases. Administrative precedent cannot be used as a substitute for evidence to support a finding of fact.

MDU does not dispute that historical averages may have been appropriate to project revenues or expenses based upon the evidence that was entered into the records of the cases cited by the Commission. That evidence, however, was not the evidence introduced into this proceeding. Understandably, the Commission did not introduce those decisions into evidence as they are irrelevant and inadmissible to the question of projecting MDU's wholesale margins for the 2002 test year.

As noted by the Commission, MDU has not challenged the three year historical average used by the Commission to project bonuses or office supply expenses for the test year. Regarding bonuses, evidence supported the use of a historical average as a reasonable projection for the 2002 test year. Although MDU believes the preponderance of evidence did not support a finding of fact to project office supply

expenses based upon a historical average, MDU chose to limit the issue in this appeal to the Commission's most egregious error – the projection of wholesale electric margins.

In an attempt to flavor its brief, the Commission states at footnote 4 that while the costs of MDU's off system sales were borne entirely by ratepayers, MDU (and its shareholders) enjoyed all the benefits of the increased revenue from off system sales. A utility's costs are not "borne" by customers. Customers pay a price approved by the Commission for electric service. The utility bears, in their entirety, the costs of providing that service. While one may argue whether a price charged by a utility is reasonable or unreasonable, the costs of providing the service are always the responsibility of the utility. Moreover, retail customers benefited greatly by MDU's off system electric sales. The Commission acknowledges that MDU has not raised its retail electric rates since 1986. Despite inflationary pressures over the last 16 years, MDU has been able to maintain stable electric rates in part because it was able to offset cost increases through the sale of off system electricity. For example, evidence presented by Mr. Diller showed that in 1997 MDU earned approximately a 12% rate of return on its equity investment notwithstanding it had nearly $2.5 million of wholesale margins. In other words, in the absence of wholesale electric sales, MDU would have had to increase its retail electric rates by $2.5 million to realize the return on equity that the Commission had previously found reasonable.

The Commission's statement in its footnote, and others throughout its brief, suggest the real but unspoken rationale for its use of a historical average was not that it was a reasonable projection of wholesale electric margins for the 2002 test year, but

rather it was a means of extracting from MDU what the Commission viewed as excessive profits during the historical period. The Commission has no authority to engage in such retroactive ratemaking. Montana-Dakota Utilities Co. v. Public Service Commission, 431 N.W.2d 276, 280-281 (N.D. 1988). Retroactive ratemaking is a method of balancing earnings from a prior period by adjusting future rates to compensate for prior rates. Id. The prohibition against retroactive ratemaking not only prevents a utility from increasing future rates to recoup past deficiencies in revenues, it also prohibits a commission's use of past profits to justify confiscatory future rates. In re: Intrastate Industrial Sand Rates, 66 N.J. 12, 327 A.2d 427 (1974).

In Elizabethtown Water Company v. New Jersey Board of Public Utilities, 205 N.J.Super. 528, 501 A.2d 567 (1985) [case attached], the Court reviewed an agency decision that was similar in effect to the Commission's order in this case. In Elizabethtown, the agency delayed the effective date of a needed rate increase to offset what the Board deemed as an overearnings situation in prior successful years. On appeal, the reviewing Court held this was impermissible retroactive ratemaking stating "the Legislature has not vested general authority in the Board to direct refunds or defer increases otherwise appropriate simply because the utility has without fault achieved overearnings." 501 A.2d at 540. Similarly, the Commission in this case had no authority to engage in retroactive ratemaking by ordering a rate reduction to compensate for perceived overearnings in prior years.

Finally, the Commission's brief points to the general principles of appellate review that decisions of an administrative agency are presumptively correct and the expertise of the agency is entitled to appreciable deference on technical matters.

Triangle Oilfield Service, Inc. v. Hagen, 373 N.W.2d 413 (N.D. 1985). In this case, however, the Commission enjoyed and demonstrated no particular expertise in projecting wholesale electric margins. The Court is equally capable of evaluating the testimony of the witnesses on this issue. Moreover, the general presumption of correctness applies only in the absence of evidence to the contrary. In re Superior Service Company, 94 N.W.2d 84, 88-89 (N.D. 1958). The presumption cannot substitute for evidence to support a finding of fact. When a finding is not supported by a preponderance of the evidence, the decision must be reversed. Triangle Oilfield Service, Inc. v. Hagen, 373 N.W.2d 413 (N.D. 1985). The general presumption is also inconsistent with the principle, acknowledged by the Commission, that when a party seeks to change a utility's rates, the burden is on that party to show the existing level of rates is unfair and unreasonable. Application of Montana-Dakota Utilities Co., 111 N.W.2d 705, 708 (N.D. 1961). Although the Complaint in this case was brought in the name of the Public Service Commission "Staff," the Staff is not a separate constitutionally or statutorily recognized entity. The "Staff" is part of the Commission. The Commission cannot overcome its burden of producing evidence based upon a general presumption that its resulting order is correct.

CONCLUSION

The parties recognize that the key question before the Court is whether, based upon the evidence, a reasoning mind could find that a three year historical average of wholesale electric margins was an accurate projection of wholesale margins for the 2002 test year. Based upon a preponderance of the evidence – indeed the only

evidence on the subject – a reasoning mind could only find that market conditions had changed drastically from 1999-2001 such that a three year historical average was not a reasonable projection of wholesale electric margins for the 2002 test year.

In a footnote, the Commission seeks to limit the Court's authority to remand this matter by stating it is not the Court's responsibility to determine the best formula to project wholesale margins. While that may be correct, it is the responsibility of the Court to remand this matter to the Commission and direct the Commission to make a finding of fact based upon a preponderance of the evidence. In this case, the evidence established that a reasonable level of wholesale margins for the 2002 test year is $6.430 million. MDU requests that the case be remanded to the Commission with specific direction to enter Findings of Fact, Conclusions of Law and an Order in accordance with that evidence and that the Commission not be given another opportunity to enter an order inconsistent with the evidence.

Dated this 3rd day of September, 2002.

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By: _____
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Superior Court of New Jersey,
Appellate Division.

In the Matter of the Petition of ELIZABETHTOWN WATER COMPANY for an Increase in Rates.
In the Matter of ANALYSIS OF EARNINGS OF ELIZABETHTOWN WATER COMPANY.
ELIZABETHTOWN WATER COMPANY,
Petitioner-Appellant,
v.
NEW JERSEY BOARD OF PUBLIC UTILITIES,
Respondent-Respondent.

Argued Nov. 4, 1985.
Decided Nov. 27, 1985.

*528 SYNOPSIS

Appeal was taken from decision of the Board of Public Utilities, 62 P.U.R. 4 th 613, in a water rate case. The Superior Court, Appellate Division, Morton I. Greenberg, P.J.A.D., held that Board engaged in prohibited retroactive rate making when it held newly approved rate increase in abeyance until deference in revenues between those that otherwise would be allowed under the new rates exceeded the current rates by amount of overearnings for certain prior years.

Reversed and remanded.

J.H. Coleman, J.A.D., filed opinion concurring in part and dissenting in part.

West Headnotes

[1] **Waters and Water Courses** 203(15)
405k203(15) Most Cited Cases

Public utility water company did not consent to determination new rates by virtue of its letter suggesting a method to deal with prior overearnings where in language free of ambiguity utility contended that if prior earnings were to be considered the Board of Public Utilities should take into account unfavorable earnings period prior to period analyzed by the Board, a position consistent with utility's response to staff report concluding that in subject period the utility achieved return in excess of that contemplated by orders in two rate proceedings, and utility never consented to the Board isolating for retroactive consideration a period starting with year of favorable earnings.

[2] **Waters and Water Courses** 203(12)
405k203(12) Most Cited Cases

Courts have authority to review actions of the Board of Public Utilities in water rate cases but do not have power initially to fix rates.

[3] **Waters and Water Courses** 203(12)
405k203(12) Most Cited Cases

In reviewing action of Board of Public Utilities in a water rate case the reviewing court should consider, among other things, whether the Board's action violates legislative policy expressed or implied in the governing act.

[4] **Waters and Water Courses** 203(6)
405k203(6) Most Cited Cases

Because rate making is a legislative function, if the Legislature sets forth adequate standards, the Board of Public Utilities, as the Legislature's agent in a water rate case, has broad discretion in exercising the authority provided it adheres to the standards.

[5] **Waters and Water Courses** 203(15)
405k203(15) Most Cited Cases

Board of Public Utilities engaged in retroactive rate making in public utility water company rate case where it held the new rates in abeyance until difference in revenues between those that would be received under new rates, as against those received under current rates, equaled the amount of prior earnings in excess of rate contemplated by then existing rate orders; in any event, if the Board was to consider past results to deter future earnings, it was arbitrary to use cutoff date reflecting years of excess earnings, without considering prior years of lean earnings. N.J.S.A. 48:2-21(b), par. 1.

[6] **Waters and Water Courses** 203(11)
405k203(11) Most Cited Cases

[6] **Waters and Water Courses** 203(15)
405k203(15) Most Cited Cases

Legislature has not vested general authority in the Board of Public Utilities to direct refunds or defer increases otherwise appropriate simply because a

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water utility has without fault achieved overearnings. N.J.S.A. 48:2-21(b), par. 1, 48:2-21.11 to 48:2-21.13, 48:2-29.3, 48:2-29.4.

****568 *530** Brendan T. Byrne, Roseland, and William R. Holzapfel, New York City, for appellant (Carella, Byrne, Bain & Gilfillan, Roseland, and William R. Holzapfel, New York City, Francis R. Perkins & Thomas C. Kelly, New York City, attorneys; Brendan T. Byrne, Roseland, William R. Holzapfel, Gwenellen P. Janov and Dennis P. Harkawik, New York City, on brief).

Helene S. Wallenstein, Deputy Public Advocate, for respondent Alfred A. Slocum, Acting Public Advocate (***531** Alfred A. Slocum, attorney pro se, Helene S. Wallenstein on brief).

Bertram P. Goltz, Jr., Deputy Atty. Gen., for respondent Board of Public Utilities (Irwin I. Kimmelman, Atty. Gen., attorney; James J. Ciancia, Asst. Atty. Gen., of counsel; Bertram P. Goltz, Jr., on brief).

Stryker, Tams & Dill, Newark, submitted a brief *amicus curiae* for New Jersey Utilities Association, Inc. (Richard B. McGlynn, Newark, of counsel, Mark L. Mucci, Newark, on brief).

***530** Before MORTON I. GREENBERG, J.H. COLEMAN and LONG, JJ.

***531** The opinion of the court was delivered by

MORTON I. GREENBERG, P.J.A.D.

This matter comes on before this court on appeal from a decision and order of respondent Board of Public Utilities, 62 *PUR*4th 613 ("Board") in a rate case.

The case originated on December 2, 1983 when appellant, Elizabethtown Water Company ("Elizabethtown"), a public utility water company subject to the regulatory jurisdiction of the Board, filed a petition with the Board seeking an increase in rates. Elizabethtown's request was contested by the public advocate and the matter was referred by the Board to the Office of Administrative Law for disposition as a contested case. During the ensuing proceedings it was established that although Elizabethtown had not departed from its filed tariff, it nevertheless had earnings in 1982 and 1983 exceeding its return on equity as authorized by the Board in rate determinations governing Elizabethtown effective January 1, 1982 and January 1, 1983. Indeed Elizabethtown admitted that although it was authorized to receive a return on equity of 14.5% during those years, it had earned 15.69% on average equity in 1982 and slightly over 16% on average equity in 1983. It did appear, however, that notwithstanding these favorable results Elizabethtown was suffering a downturn in its earnings. On July 13, 1984 an administrative law judge issued an initial decision ***532** recommending that Elizabethtown be granted relief. This decision was sent to the Board for review and a final decision.

At about the same time the rate case was proceeding, the Board's staff at its direction was examining Elizabethtown's earnings to ascertain whether they were in excess of those produced by just and reasonable rates. The staff in its inquiry concluded that Elizabethtown's achieved return from January 1, 1982 through July 31, 1984 was $2.2 million in excess of the return contemplated by orders in Elizabethtown's two previous rate proceedings effective January 1, 1982 and January 1, 1983.

Elizabethtown filed a response to the staff report with the Board dated June 28, 1984 disputing certain of its calculations, asserting it would be unfair to consider 1982 and 1983 while excluding its less successful year of 1981 and contending that in any event an adjustment for 1982 and 1983 ****569** earnings would be unprecedented retroactive ratemaking. Subsequently Elizabethtown, following discussions with the Board's staff, addressed a letter dated August 28, 1984 to the Board asserting that the staff report substantiated Elizabethtown's contention that the company would have poor earnings in 1984, thus jeopardizing its ability to market new debentures and affecting its fiscal integrity. The company further asserted that the staff and Elizabethtown agreed that its underearnings during 1984 would more than offset its overearnings in 1983. Elizabethtown stated it had agreed with the staff that overearnings of $1,150,000 in 1982 could be offset by applying against them projected 1984 underearnings, to the extent these underearnings were not used to offset 1983 overearnings, and by extending the date new rates approved by the Board would go into effect. However while setting forth a method to treat the overearnings, the company stated that it would be unfair to isolate the 1982 earnings from those of prior years. It contended that its return in 1981 was only 11.15% so when that year was combined with 1982 its return was 13.4%, a rate

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below that allowed by the Board. It further asserted that it should not be required to suffer an adjustment for 1982 without appropriate *533 adjustments being given for that portion of the authorized rate of return not achieved for the nine years prior to 1982.

On September 24, 1984 the Board issued its decision and order reciting it "affirms" the initial decision with certain modifications. The Board acknowledged Elizabethtown's need for a rate increase and ordered higher rates to cover a projected revenue deficiency. But it also took the overearnings issue into account and concluded that while Elizabethtown had not been at fault in achieving them, the ratepayers should receive recognition of them to the extent of $1,150,000, the amount acknowledged by the staff and Elizabethtown. The Board determined that the most appropriate way to make the ratepayers whole for this amount was to set it off against the rate increase awarded by the Board. Thus it ruled the new rates would be held in abeyance until the difference in revenues between those that would otherwise be allowed under the new rates exceeded the current rates by $1,150,000. It contemplated that the effective date of the new rates would be about February 1, 1985, a date subject to refinement by Elizabethtown, the staff and the public advocate.

On October 25, 1984 Elizabethtown appealed to this court from the Board's order. The public advocate subsequently cross-appealed. In addition the New Jersey Utilities Association, Inc. has participated in this appeal by filing, with leave of the court, a brief *amicus curiae.* Immediately after appealing, Elizabethtown sought interim relief. By our order of October 31, 1984, entered after a hearing, we granted Elizabethtown's motion and ordered that the imposition of the new rates would not be deferred by reason of the adjustment for the overearnings. Our order provided, however, that depending upon the outcome of this case Elizabethtown might have to refund payments to its ratepayers. In entering this order we considered the obvious fact that unless immediate relief was granted the case could become moot because the time of deferment of the new rates could expire before this case was decided. In fact a tariff was promptly prepared and approved reflecting the *534 new rates and went into effect on November 9, 1984, subject to the outcome of this appeal.

On this appeal Elizabethtown asserts that the Board's action in deferring the increase is impermissible retroactive ratemaking, depriving it of rates otherwise required to produce a just and reasonable rate of return and thus establishing confiscatory rates. The Utilities Association contends the Board's action is a unilateral assumption of authority to revise retroactively a previously final, approved rate and is thus an illegitimate assumption of authority.

**570 The public advocate contends that Elizabethtown by its letter of August 28, 1984 agreed with the Board's action subsequently taken and thus is bound by it. According to the public advocate had Elizabethtown rejected any consideration being given to the overearnings the Board might have taken action to reduce its rates. It further asserts that in any event the Board has not engaged in retroactive ratemaking but rather its decision and order represents a finding that the rates in effect at the time of its ruling, having been found to be just and reasonable, presumptively continue to be reasonable until the earned return on equity for the current period does not exceed the allowed return on equity. The public advocate further argues that the Board, by reason of the deferment, awarded Elizabethtown a larger increase in the future than would otherwise have been allowed. Overall the public advocate contends the Board acted within its legal authority and pursuant to its equitable duty to protect the ratepayers and to insure that they pay rates that are just and reasonable, but no more.

The Board asserts that by deferring the effective date of the new, higher rates it simply extended the then current rate period to allow earnings above the authorized return to average out in the normal course. It thus claims that it is not engaging in impermissible retroactive ratemaking.

The public advocate's cross-appeal is related to its answer to the appeal. It argues that under the Board's order there is a *535 linkage between the amount of the award and its effective date so that the Board allowed Elizabethtown higher rates than it would have otherwise permitted had it contemplated that the award would be immediately effective. Thus the public advocate asserts that if we adopt Elizabethtown's position, the case should be remanded to the Board for a redetermination of the relief to be granted Elizabethtown. Accordingly the public advocate states that only if Elizabethtown is successful need we address the cross-appeal.

[1] Firstly, we deal with and reject the contention that Elizabethtown consented to the determent of the new rates by its letter of August 28, 1984. While it is true that in the letter Elizabethtown suggested a method to deal with overearnings, in language free of

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ambiguity it contended that if prior earnings were to be considered the Board should take into account unfavorable years before 1982, a position consistent with its June 28, 1984 response. Elizabethtown never consented to the Board isolating for retroactive consideration a period starting January 1, 1982, a time of favorable earnings. Further we see no merit to the public advocate's contention that but for Elizabethtown's alleged agreement to accept the deferment the Board might have taken earlier action to reduce Elizabethtown's rates inasmuch as the staff report was not rendered until 1984. Thus a prospective reduction at that time could have hardly impacted on Elizabethtown's 1982 and 1983 rates or earnings. Accordingly we must address the larger issue on this appeal of retroactive ratemaking raised by Elizabethtown.

In view of the dispute among the parties as to whether the Board engaged in retroactive ratemaking we think it important to quote the germane portion of the September 24, 1984 decision and order at length. The Board there said:

> A review of the Staff exhibits supplied to and discussed with petitioner [Elizabethtown], as well as petitioner's responses thereto, leads the Board to the inescapable conclusion that petitioner achieved a rate of return on average common equity significantly higher than that permitted by the Board during the rate periods in question. According to Staff's calculations, petitioner in the ***536** 1982 rate period achieved excess earnings over the permitted 14.5% rate of return on equity of approximately $2 million in revenues. This analysis also supports the conclusion that a level of overearnings continued through the end of 1983, with a significant downturn in earnings ****571** in the first half of 1984. Taking into account the company's submission with respect to earnings through July, 1984, Staff concludes that there has been to date a level of overearnings of approximately $2.2 million in revenues.
>
> ....
>
> The Board believes that the ratepayer must be made whole in compensation for a level of charges which, in fact, have exceeded the levels prescribed by the Board. Taking all these factors before us into consideration, the majority of the Board concludes that the ratepayers should receive recognition for over- earnings by petitioner in the amount of $1.15 million. This is the amount with which the Staff and the Petitioner basically agreed, for purposes of possible settlement, during the conferences held on the Board's investigation into over-earnings. The Board believes that this conclusion does not undermine our responsibility to set reasonable rates for the future, as we have done by virtue on the rate order included herein.
>
> The Board further concludes that the most appropriate methodology to make the ratepayers whole with respect to this level of overrecovery, is to set off this amount against the level of rate increase awarded herein, which is necessary to give petitioner an opportunity to achieve in future a reasonable rate of return. We will therefore hold the new rates found to be reasonable in this order in abeyance until the difference in revenues between those that would be received under the new rates, as against those received under current rates, equals $1.15 million. It is anticipated that this recovery should be completed on or about February 1, 1985; the date new rates shall be permitted to go into effect shall be subject to an accounting procedure agreed upon by petitioner, Board's Staff and Rate Counsel, which will determine the exact timing of the implementation of this rate order.

[2][3][4] In reviewing the foregoing decision and order it is appropriate for us to restate certain basic propositions. We, of course, are not empowered initially to fix rates but we do have the authority to review the Board's actions. *In re Intrastate Industrial Sand Rates,* 66 *N.J.* 12, 19-20, 327 *A.*2d 427 (1974). In our review we should consider, among other things, whether the action of the Board violates legislative policies expressed or implied in the act governing it. *See Campbell v. Dept. of Civil Service,* 39 *N.J.* 556, 562, 189 *A.*2d 712 (1963). We further recognize, however, that as ratemaking is a legislative function, if the Legislature sets forth adequate standards, the Board, as the Legislature's agent, is vested with broad discretion in exercising the authority ***537** provided it adheres to the standards. *In re Intrastate Industrial Sand Rates, supra,* 66 *N.J.* at 21, 327 *A.*2d 427.

The Legislature has set the standard for the Board in ratemaking in *N.J.S.A.* 48:2-21(b)(1) by providing that the Board shall fix:

> ... just and reasonable individual rates ... which shall be imposed, observed and *followed thereafter* by any public utility, whenever the board shall determine any existing rate ... to be unjust, unreasonable, insufficient or unjustly discriminatory or preferential. (Emphasis added.)

Inasmuch as the establishment of a rate is a legislative act it follows that the Board's ratemaking authority is prospective. *See In re Lambertville Rates v. N.J. Bd. Pub. Util. Comm'rs,* 79 *N.J.* 449,

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457, 401 *A.*2d 211 (1979); *In re Intrastate Industrial Sand Rates, supra,* 66 *N.J.* at 28, 327 *A.*2d 427. Nor surprisingly the principle that ratemaking is a prospective process is applied ordinarily when utilities seek increases in rates. This principle is applied to deny applications for increase which would permit a utility to recoup past deficiencies in revenues. *In re N.J. Power & Light Co.,* 15 *N.J.* 82, 104 *A.*2d 1 (1954); *see also* **572*In re Revision of Rates Toms River Water Company,* 82 *N.J.* 201, 213, 412 *A.*2d 430 (1980). But this rule against retroactive ratemaking may work for as well as against a utility as the Supreme Court explained in *In re Intrastate Industrial Sand Rates:*

> And while it was once thought by our courts to be just and reasonable to permit a utility, by a surcharge on newly established rates, to recoup revenue deficiencies which it had suffered in the recent past ... that philosophy, too, has been specifically overruled. [Citation omitted.]
>
> And of course this rule, of looking to the future and not the past, works both ways. In *Los Angeles Gas & Electric Corp. v. R.R. Comm'n of California,* 289 *U.S.* 287, 313, 53 *S.Ct.* 637, 647, 77 *L.Ed.* 1180, 1197 (1933), the Supreme Court held:
>
> Deficits in the past do not afford a legal basis for invalidating rates, otherwise compensatory, any more than past profits can be used to sustain confiscatory rates for the future. [66 *N.J.* at 23, 327 *A.*2d 427]

See also In re N.J. Power & Light Co., supra, 15 *N.J.* at 89, 104 *A.*2d 1.

[5] We are satisfied from the Board's decision and order that it engaged in retroactive ratemaking. While the Board **538** denied it was doing this what it in fact did is manifest from its language:

> ... that the most appropriate methodology to make the ratepayers whole with respect to this level of overrecovery, is to set off this amount against the level of rate increase awarded herein, which is necessary to give petitioner an opportunity to achieve in future a reasonable rate of return. We will therefore hold the new rates found to be reasonable in this order in abeyance until the difference in revenues between those that would be received under the new rates, as against those received under current rates, equals $1.15 million.

In addition the Board ended its order and decision by stating: "[t]herefore, the rate increase permitted herein, will not be permitted to take effect until on or about February 1, 1985, but in no event until verification of the amount of *refund* has been resolved ...." (Emphasis added). It is true that the Board did not in form order a refund, but to Elizabethtown and the ratepayers that was the effective consequence of the order, a result which the Board well understood as it referred itself to the amount of the "refund." Our point is that in determining what was prospectively a just and reasonable rate the Board adjusted for prior results.

In addition to denying that the Board engaged in retroactive ratemaking, the public advocate and attorney general assert that the courts have always applied the rule against retroactivity for the protection of the ratepayer, not the utility, and thus the Board's decision and order should be sustained. They point out that a utility faced with an earnings shortfall may seek rate relief and thus arguably does not need a retroactive increase in that circumstance. *See In re Lambertville v. N.J. Bd. of Pub. Util. Commr's, supra,* 79 *N.J.* at 457, 401 *A.*2d 211; *In re N.J. Power & Light Co., supra,* 15 *N.J.* at 93, 104 *A.*2d 1; *In re New Jersey Power & Light Co.,* 9 *N.J.* 498, 527, 89 *A.*2d 26 (1952). Respondents distinguish a shortfall situation from a case in which a utility is achieving overearnings as in the latter circumstance its ratepayers do not have options similar to those of the utility in the former to obtain rate relief.

As a policy matter there is some force in these arguments. But they overlook the fact that the Board's powers are limited **539** by *N.J.S.A.* 48:2-21(b)(1) which authorizes it to fix just and reasonable rates which shall be "... followed thereafter by any public utility ...." Thus even though the Board undoubtedly considered its order fair, by effectively applying the decision to a period before its decision and order it departed from the legislative mandate to apply rates after they are fixed.

We also point out that while the Board's order may seem superficially fair, in reality it is not. Elizabethtown in its letter of **573 August 28, 1984 asserted that in the nine years prior to 1982 it did not achieve its authorized rate of return. It is difficult to justify applying the overearnings in 1982 and 1983 to defer the effective date of the 1984 increase while ignoring less favorable results for other years. Further it cannot be urged that the Board simply went back to the effective date of its last rate order as that date was, according to its decision and order, January 1, 1983. In our view if the Board was to consider past results to defer future earnings, it was arbitrary to cut the date off at January 1, 1982. We further point out that to some extent there would not be an identity among the ratepayers who contributed to the overearnings in 1982 and 1983 and those who later

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benefited from the deferment. Thus if the basic premise of the Board's order that past earnings may be used to adjust (albeit only downward) current rates is true, certain of the earlier ratepayers under the Board's order made payments on behalf of their successors. Inasmuch as the Supreme Court in *In re Lambertville Rates v. N.J. Bd. Pub. Util. Commr's, supra,* 79 *N.J.* at 457, 401 *A.*2d 211, indicated that retroactive increases should be avoided so that new consumers are not called upon to pay a present surcharge for service to prior customers, it follows that retroactive decreases should be avoided so that prior ratepayers do not subsidize their successors.

[6] It is also significant that in certain specific but limited circumstances the Legislature has allowed the Board to take action similar to that which it took here. Under *L.* 1983, *c.* 461, *N.J.S.A.* 48:2-21.11 to 21.13, if an electric utility recovers money ***540** for certain costs from any insurance carrier or as a result of a legal action or settlement, the recovery may be used to reduce its rates when the Board next fixes them if the Board determines that the costs recovered are being charged to the ratepayers. Further under *N.J.S.A.* 48:2-29.3 and *N.J.S.A.* 48:2-29.4 when the Board has authorized a utility to collect a surcharge to raise a definite amount of money for a specified purpose, it may order the utility to refund any excess collected. Thus when the Legislature has desired to authorize the Board to order refunds or reduce future rates by reason of past events it has expressly done so. The absence of such provisions in *N.J.S.A.* 48:2-21(b)(1) leads us to conclude the Legislature has not vested general authority in the Board to direct refunds or defer increases otherwise appropriate simply because the utility has without fault achieved overearnings.

The Board in its decision relied on *Plainfield, etc., Water Co. v. Bd. Pub. Utility Commrs.,* 117 *N.J.L.* 18, 186 *A.* 692 (Sup.Ct.1936) and *Re Narragansett Elec. Co.,* 57 *PUR*4th 549 (R.I. PUC 1984) [FN1] but these decisions do not support its action. It is true that in *Plainfield* the court permitted the Board retroactively to order refunds of excess amounts collected under a surcharge but only because it found the refund was specifically authorized by *L.* 1935, *c.* 48, the source of *N.J.S.A.* 48:2-29.3 and *N.J.S.A.* 48:2- 29.4. *Re Narragansett Elec. Co.* was based on Rhode Island law which seems not have language similar to *N.J.S.A.* 48:2-21(b)(1) providing that rates shall be fixed to be charged "thereafter." Further Rhode Island law vests its regulatory agency with broad refund powers and, contrary to the practice in this State, allows a utility to make a retroactive recovery for costs for events such as severe weather which could not be anticipated. In fact *Narragansett* is no help at all to respondents as the commission there clearly stated that the retroactive adjustments would result in refunds. Thus unlike the ***541** Board here it acknowledged the reality of what it was doing. Finally we point out that while we rely on New Jersey law for our decision, in fact foreign law supports our result. *See In re Cent. Vermont Public Service Corp.* 144 *Vt.* 46, 473 *A.*2d 1155 (Sup.Ct.1984); *South Carolina, Etc. v. Public Serv. Com'n,* 275 *S.C.* 487, 272 *S.E.*2d 793 (Sup.Ct.1980). Indeed the Vermont ****574** case clearly demonstrates that deferring an increase is in reality a provision for a refund and is retroactive ratemaking by its statement that "[i]n other words, retroactive ratemaking is a device that enables a utility to balance its accounts for a prior period of time by making a future adjustment in its rates." 144 *Vt.* at 52, 473 *A.*2d at 1158.

> FN1. We are advised that *Narragansett* has been appealed to the Supreme Court of Rhode Island.

In view of our determination on Elizabethtown's appeal we are constrained to consider the cross-appeal. As we have indicated the public advocate contends that there was a linkage between the Board's resolution of the rate issues and the overearnings analysis and in reaching its decision and order the Board took into account the impact that the delay in rate increase would have upon Elizabethtown's financial condition. The public advocate asserts that in doing so the Board took "several tangible steps to mitigate the financial impact on Elizabethtown," resulting in a financial benefit to Elizabethtown. These related to calculation of Elizabethtown's surplus and determination of the test year. Thus the public advocate contends that if we accept Elizabethtown's position that the deferment was unlawful retroactive ratemaking we should remand the matter to the Board for redetermination of the relief to be granted Elizabethtown. We have carefully reviewed this contention and find it difficult to support on the record. We note, however, that the Board in its brief does agree with the public advocate that if we reverse on the appeal we should remand the matter. In the circumstances we have concluded that we should not in the first instance pass on the issues raised in the cross- appeal. Rather the matter should be remanded to ***542** the Board to consider the public advocate's contention. We are confident that the

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proceedings on the remand will not be used to circumvent the result we have reached.

In conclusion insofar as the decision and order of September 24, 1984 required that the ratepayers be given recognition for the overearnings of $1,150,000 it is reversed and the decision and order of September 24, 1984 shall be deemed effective as of November 9, 1984 when our order of October 31, 1984 forinterim relief was implemented. The reversal, however, is subject to the proceedings on the remand which may result in a modification of the decision and order of September 24, 1984. The matter is remanded to the Board for further proceedings not inconsistent with this opinion. We do not retain jurisdiction.

COLEMAN, J.H., J.A.D., concurring in part and dissenting in part.

I agree with the majority that the Board may have engaged in retroactive ratemaking. I dissent from the majority's determination that the retroactive ratemaking in the present case was impermissible. I agree with the contention advanced by the Public Advocate and the Attorney General that the rule against retroactive ratemaking is to be applied only when it protects the ratepayer, not the utility. When a utility discovers that an existing rate is not yielding what has been determined to be a reasonable return, "it can act as speedily as it sees fit to move for a correction of inadequate rates...." *In re N.J. Power & Light Co., supra,* 15 *N.J.* at 93, 104 *A.*2d 1. By acting expeditiously, a utility can prevent an existing rate from becoming confiscatory. My conclusion is consistent with the language quoted from *In re Intrastate Industrial Sand Rates, supra,* 66 *N.J.* at 23, 327 *A.*2d 427 which indicates that past profits cannot be used to sustain confiscatory rates for the future. There has been no showing that continuation of the rate fixed by the Board's ***543** order effective January 1, 1983 until February 1, 1985, would be confiscatory. On the other hand, unless the Board's decision is affirmed, the ratepayers would have no recourse for paying utility bills that were unnecessarily high. I find that the Board has followed its broad regulatory function and has exercised its discretion to protect ratepayers; while at the same time, it insured that the rate of return on the utility's equity is not confiscatory. In balancing the interest of the ****575** utility and the ratepayers, the Board exercised its "broad discretion, based on the circumstances, to fix an effective date for such increase." *In re Lambertville, supra,* 79 *N.J.* at 457, 401 *A.*2d 211.

When the Board deferred the effective date of its order from September 24, 1984 to February 1, 1985 so that the $1.15 million could be recovered by ratepayers, the net effect was to continue the prior rate until February 1, 1985. In so doing, the Board made the new rate prospective only. Hence, I find compelling the argument that this is not retroactive ratemaking. Even if it is, I would hold that it is not impermissible. Additionally, continuation of the prior rates does not violate *N.J.S.A.* 48:2-21b(1) which requires a utility to follow a rate once it has been fixed by the Board. I read this statute as requiring the utility to follow the rate from its effective date until altered by the Board. I do not interpret this statute as requiring the effective date to coincide with the date on which the Board's order is issued.

Finally, I perceive no substantial problem related to changes occurring within the class of ratepayers between 1982 and February 1, 1985. On balance, the changes which occurred would probably be insignificant. Moreover, the Legislature did not envision any meaningful problem in the changing class of ratepayers when it provided for credits or refunds under *N.J.S.A.* 48:2-21.11 to 21.13.

I would therefore affirm.

501 A.2d 567, 71 P.U.R.4th 436, 205 N.J.Super. 528

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STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

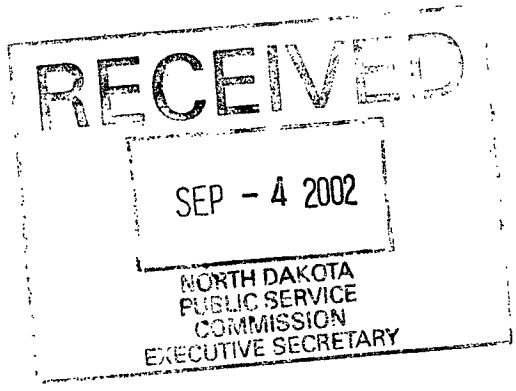
Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

AFFIDAVIT OF MAILING



STATE OF NORTH DAKOTA)
) ss
COUNTY OF BURLEIGH)

The undersigned, being duly sworn, deposes and says that I am a United States citizen, over 18 years of age, and on September 3, 2002, I served a copy of the attached:

APPELLANT'S REPLY BRIEF AND NOTICE OF ORAL ARGUMENT

by placing a true copy in a postage paid envelope addressed to each person named below, at the address stated below, which is the last known address of the addressee, and by depositing said envelope in the United States mail at Bismarck, North Dakota.

Doug Bahr
Assistant Attorney General
Department 125
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Bismarck, ND 58505-0041

Illona Jeffcoat-Sacco
ND Public Service Commission
State Capitol -- 12th Floor
Bismarck, ND 58505-0480

138 PU-399-01-186 Pages: 2
Affidavit of Mailing
by Montana-Dakota Utilities Co., a Division of MDU Re
09/04/2002C: Comm Legal PUD (3) Mike AG's Office

Karol A. Cossette

Subscribed and sworn to before me September 3, 2002, a Notary Public for the County of Burleigh, State of North Dakota. My Commission expires: 1/24/08

KATHI OSTEEN
Notary Public
State of North Dakota
My Commission Expires Jan. 24, 2008

COPY

OFFICE OF ATTORNEY GENERAL
STATE OF NORTH DAKOTA

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NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

August 19, 2002

Wayne Stenehjem
ATTORNEY GENERAL

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Ms. Debra Simenson, Clerk
Burleigh County District Court
P.O. Box 1055
Bismarck, ND 58502-1055

Re: Montana-Dakota Utilities Co. v. North Dakota Public Service Commission; Case No. 08-02-C-01719

Dear Ms. Simenson:

Enclosed are the original Appellee's Brief and an Affidavit of Service by Mail in the above-entitled case. Please file these documents with the court.

Sincerely,

Douglas A. Bahr
Assistant Attorney General
Office of Attorney General
500 North 9th Street
Bismarck, ND 58501-4509
Telephone (701) 328-3640
Facsimile (701) 328-4300

jjt
Enclosures
cc: Daniel S. Kuntz (w/encs.)

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Letter to Clerk of Court re Appellee's Brief

by Public Service Commission by Doug Bahr, AG Attor

08/22/2002C: Comm Legal PUD (3) Mike AG's Office .

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STATE OF NORTH DAKOTA	IN DISTRICT COURT
COUNTY OF BURLEIGH	SOUTH CENTRAL JUDICIAL DISTRICT
Montana-Dakota Utilities Co., Appellant, v. North Dakota Public Service Commission, Appellee.	**APPELLEE'S BRIEF** **Civil No. 08-02-C-01719**

STATEMENT OF THE CASE

On September 7, 2001, Advocacy Staff (Staff) of the North Dakota Public Service Commission (Commission) filed a Complaint against Montana-Dakota Utilities Co. (MDU). (Doc. 16.)[1] The Complaint alleged that MDU's "rates for electric services are unjust and unreasonable in that MDU is recovering more revenue than necessary to earn a reasonable return on its investment in North Dakota." (Doc. 16, ¶ IV.) The Complaint sought a reduction[2] in MDU's retail electric rates, asserting that "MDU's rates for electric service should be decreased by $9.155 million annually . . . ." (Doc. 16, ¶ V.) On September 19, 2001, the Commission found that the Complaint states a prima facie case, and served the Complaint on MDU. (Docs. 19, 20.) MDU subsequently filed an Answer to the Complaint. (Doc. 21.)

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[1] Documents are referenced based upon the document number provided in the Certificate of Record on Appeal.

[2] If the Commission determines an existing rate is unreasonable, the Commission may only fix new rates to be charged in the future. Montana-Dakota Utils. Co. v. Public Serv. Comm'n, 431 N.W.2d 276, 280 (N.D. 1988). The Commission cannot recover and return to the ratepayers any excess revenue obtained by the utility due to the unreasonable rate.

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Appellee's Brief
by Public Service Commission by Doug Bahr, AG Attor
08/22/2002C: Comm Legal PUD (3) Mike AG's Office

A hearing on the Complaint was held February 25 and 26, 2002. (Docs. 84, 85.) On April 24, 2002, the Commission issued its Findings of Fact, Conclusions of Law and Order. (Doc. 101.) Based upon its findings and conclusions, the Commission ordered MDU to "implement an across the board rate reduction sufficient to produce a total annual rate revenue decrease of $4.273 million." (Doc. 101, p. 15.) The rate reduction was to be effective for electric service on and after May 8, 2002. (Doc. 101, p. 15.) On April 25, 2002, MDU appealed the Commission's April 24, 2002, Order. (Doc. 107.)

NATURE OF THE CASE AND ISSUE

"An investor-owned public utility, such as MDU, is entitled to earn revenue that will allow it to meet its expenses and earn a fair and reasonable rate of return for its investors." Montana-Dakota Utils. Co. v. Public Serv. Comm'n, 413 N.W.2d 308, 310 (N.D. 1987). The primary issue in a rate investigation is to determine if the rates complained of will yield a fair rate of return for a reasonable time in the immediate future. Application of Montana-Dakota Utils. Co., 102 N.W.2d 329, 341 (N.D. 1960). If the public utility's revenues do not meet its expenses, a rate increase is necessary. Montana-Dakota Utils. Co., 413 N.W.2d at 310. Correspondingly, if the revenues generate an excessive rate of return for the public utility's investors, a rate decrease is necessary.[3]

A "test year" is used to determine if a utility's revenue is sufficient to meet operating expenses and a fair return on investment. Montana-Dakota Utils. Co., 413 N.W.2d at 310. It is necessary to project revenues and expenses for the test year. Application of Montana-Dakota Utils. Co., 102 N.W.2d at 341-42. In the present case,

---

[3] When a party seeks a change of rates, the burden is on the party to show the existing level of rates is unfair and unreasonable. Application of Montana-Dakota Utils. Co., 111 N.W.2d 705, 708 (N.D. 1961). In 1987, MDU's last rate adjustment, the Commission determined a return on equity of 12.71% was reasonable based upon the market conditions. (Doc. 15, p. 5.) Based upon current market conditions, the Commission found that a return on equity of 11.8% is a fair and reasonable return on equity to MDU's stockholders. (Doc. 101, p. 7.) MDU has not challenged that finding. And the record establishes that in 2000 MDU reported a return on equity of 17.95%, and in 1999 MDU reported a return on equity of 15.94%. (Doc. 15, p. 4.)

MDU challenges the Commission's method of projecting revenues for the 2002 test year. Specifically, MDU challenges the Commission's use of a three-year historical average to project wholesale margins for the 2002 test year.

STATEMENT OF THE FACTS

MDU has not had its electric rates adjusted since 1987. Based upon the market conditions at that time, the Commission determined a return on equity of 12.71% was reasonable. (Doc. 15, p. 5.)

In 2001, the Commission requested that Staff conduct a financial review of the electric operations of MDU after MDU reported a return on equity of 15.94% and 17.95% for 1999 and 2000, respectively. (Doc. 15, p. 4.) Prior to 1998, MDU's earnings were quite stable at or around 12% return on equity. In 1998, however, earnings began to increase substantially as wholesale sales increased. (Doc. 15, pp. 4-5.) MDU's additional profits from wholesale sales, along with a lower cost of capital and a lower investment base, caused MDU to over-earn in recent years. (Doc. 15, p. 5.)[4]

Since 1996, the margin, or net revenue, from MDU's wholesale electricity sales has consistently increased. The number of resale customers has consistently increased. (Doc. 15, p. 24.) And the growth in wholesale sales has nearly tripled since 1997. (Doc. 15, p. 25; Doc. 84, p. 31.) More importantly, not only has the revenue growth been substantial, so has the net margins (revenue less costs). (Doc. 15, p. 26.) The graph at Document 15, p. 26 illustrates MDU's significant net margin growth for wholesale sales. (See also Doc. 73, p. 14.) The annual margins MDU received from wholesale sales from 1996 to 2001 are as follows:

---

[4] Wholesale sales are often referred to as "sales for resale" or "off-system sales." An off-system sale is a sale of excess electricity into the wholesale market, typically to power brokers or other utilities, so that it can then be resold to other customers. The costs of producing the electricity sold by MDU's off-system sales were borne entirely by the ratepayers, while MDU (and its shareholders) enjoyed all the benefits of the increased revenue.

Year	Wholesale Margins
1996	$1,915,866
1997	$2,491,993
1998	$4,816,728
1999	$8,772,849
2000	$9,918,345
2001	$15,937,892

Based upon MDU's very high level of earnings, and thus unreasonably high rates of return to investors, the Staff initiated its Complaint seeking a decrease in MDU's retail electric rate. MDU responded by speculating, based upon numerous market and other conditions, that its projected net revenue from wholesale sales would be $6.43 million during the 2002 test year. At the hearing, Staff proposed projecting wholesale margins for the 2002 test year using the average of the margins from 1999, 2000, and 2001, adjusted for demand penalties. Under this proposal, the Staff suggested the Commission project wholesale margins of $11.696 million to the test year and reduce retail electric rates by $4.941 million annually. (Doc. 84, pp. 34-35, 48, 64, 76, 83-84; Doc. 73, p. 33.)

In support of its recommendation to use a three-year historical average to project wholesale margins for the test year, Staff explained that the historical average used actual results, rather than attempting to project, based upon numerous unknown variables, what may occur in the future. In fact, Staff identified at least 28 factors that MDU testified affect future wholesale margins. (Doc. 84, p. 33.) These factors can have significant impact on the price of wholesale electricity, and are outside the control of MDU or the Commission. They include national economy, market uncertainty, future contracts, natural gas prices, droughts, manufacturing industry, new generation capacity, natural gas supplies, weather, natural gas transportation rates, incremental operating costs, transactional risks, fuel cost differentials, transmission constraints, generation mix,

transmission access, market power of supplier, institutional inefficiencies, regulation uncertainties, stranded cost exposure, plant outages, incomplete market information, nuclear safety regulations, hedging activities, spark-spreads, conservation programs, gas exploration levels, and gas in storage. (Doc. 84, pp. 33-34; Doc. 73, pp. 16-19.) Because of these numerous uncertainties, Staff recommended actual results as a proxy for speculative future sales. (Doc. 84, p. 34.)

Staff also explained why an average of recent actual results should be used. "Using an average of recent results will smooth out recent market fluctuations and provide a normalized level going forward." (Doc. 84, p. 34.) Staff also explained that it is most appropriate to use the most recent information. (Doc. 84, pp. 51, 55.)

The Commission adopted the staff's proposed three-year historical average and directed MDU to reduce its North Dakota retail rates by $4.273 million.[5] (Doc. 101, p. 15.) In reaching its decision, the Commission made the following findings:

> 31. The staff method of normalizing sales for resale margins is based on actual transactions that have occurred during the past 3 years and then averaged to result in a proxy for expected margins in the future.
>
> . . . .
>
> 33. Diller identified 28 factors affecting future resale margins from the testimony of MDU's ten witnesses. One of the factors listed by Diller includes "new generation capacity." If price is determined by supply and demand principles discussed in this case, new electric supplies to meet new demand are critical to the long-term pricing of electricity. According to MDU's representation, the Mid-American Power Pool (MAPP) forecasts excess capacity in the future. However, Exhibit 11 entered by Commissioner Wefald shows that the North American Electric Reliability Council suggests that the MAPP capacity is inadequate for the time period of 2001-2010. This indicates that the experts can't agree on the critical element of the supply side of the price equation.
>
> . . . .
>
> 39. Staff has shown, based on historical evidence, that MDU has made significant margins in its sales for resale. MDU has attempted to predict reduced sales for resale margins through estimates of future sales and future prices.
>
> 40. The Commission finds a high degree of uncertainty associated with predictions that are affected by one or more of at least 28 factors and the large

[5] The difference between the staff's proposed rate reduction and the reduction ordered by the PSC is attributable to test year adjustments made by the PSC that are not of issue an this appeal.

> number of combinations of those factors that are outside MDU or Commission control. These factors can change dramatically as evidenced by the change in prices of natural gas in recent years. We find that using the average of sales for resale during 1999, 2000, and 2001 is most appropriate decision at this time.

(Doc. 101, pp. 8-9.)

ARGUMENT

I. The Court's Review of the Commission's Order is deferential.

A determination of an administrative agency is presumed to be correct. Triangle Oilfield Servs., Inc. v. Hagen, 373 N.W.2d 413, 415 (N.D. 1985). This Court's review of the Commission's decision is governed by N.D.C.C. ch. 28-32, which generally requires the Commission's decision to be affirmed unless the decision is not in accordance with the law, the findings of fact are not supported by the preponderance of the evidence, or the conclusions of law are not sustained by the findings of fact. Coteau Props. Co. v. Oster, 2000 ND 23, ¶ 5, 606 N.W.2d 876; Montana-Dakota Utils. Co., 413 N.W.2d at 310; Matador Ser., Inc. v. Missouri Basin Well Serv., Inc., 367 N.W.2d 749, 752 (N.D. 1985).

The North Dakota Supreme Court has explained the standard it and the district courts follow when reviewing administrative agency decisions:

> (1) we do not make independent findings of fact or substitute our judgment for that of the agency, but determine only whether a reasoning mind could have reasonably determined that the factual conclusions were supported by the weight of the evidence; (2) we exercise restraint when we review administrative agency findings; (3) it is not the function of the judiciary to act as a super board when reviewing administrative agency determinations; and (4) we will not substitute our judgment for that of qualified experts in the administrative agencies.

Sonterre v. Job Service North Dakota, 379 N.W.2d 281, 283-84 (N.D. 1985) (citations omitted); see also Coteau Props., 2000 ND 23, ¶ 2, 606 N.W.2d 876; Matador Serv., Inc., 367 N.W.2d at 752; Triangle Oilfield Servs., 373 N.W.2d at 415. Furthermore, in technical matters, the expertise of the agency is entitled to appreciable deference. Coteau Props., 2000 ND 23, ¶ 2, 606 N.W.2d 876; Montana-Dakota Utils. Co. v. Public

Serv. Comm'n, 431 N.W.2d 276, 280 (N.D. 1988). Triangle Oilfield Servs., Inc., 373 N.W.2d at 415.

II. A reasoning mind reasonably could have found that it was appropriate to project wholesale margins to the 2002 test year based on a three-year historical average.

The facts in this case are, for the most part, not in dispute. The only finding of fact challenged by MDU is the Commission's finding that it was appropriate to project wholesale margins to the 2002 test year based on a three-year historical average. Because a reasoning mind could have reasonably reached that conclusion, the Commission's finding must be upheld.

A reasoning mind could have reasonably used a three-year historical average to project wholesale margins to the 2002 test year. Using a three-year historical average is objective, measurable and concrete. It takes into account what actually has occurred, not what one speculates, based upon unknown variables, may occur in the future. As found by the Commission, there is "a high degree of uncertainty associated with predictions that are affected" by multiple factors and a combination of those factors. (Doc. 101, p. 9.) The unknown variables significantly impact both the amount and price of future wholesale sales. Based on the evidence, a reasoning mind could reasonably conclude it is better to rely on known and measurable historical information, rather than subjective, unmeasurable forecasts.

A reasoning mind could also have reasonably used a three-year historical average rather than the most recent year. The use of the three-year historical average normalizes sales, automatically making an adjustment for an unusually high or unusually low year and causing it to conform to the standard. "Using an average of recent results will smooth out recent market fluctuations and provide for a normalized level going forward." (Doc. 73, p. 20.)

Arguably, using more than a three-year historical average would cause an even greater normalizing affect. Although this may be true, a reasoning mind could reasonably

conclude that using an average of more than three-years extends the average to a time too remote from the present, thereby reducing the likelihood that the remote years reflect the market conditions of the test year. The three-years closest to the test year are most likely to reflect the conditions of the test year. It was reasonable for the Commission to use a three-year average because the wholesale margins that occurred in the most recent three years are more likely to be representative of margins to be incurred in the test year.

The reasonableness of the Commission's decision to use a three-year historical average to project wholesale margins for the test year is consistent with the Commission's past practice of using historical averages. For example, in MDU's last electric rate increase application before the Commission, MDU argued for a 5-year average related to its energy portion of other production expense. MDU's witness asserted that the use of five years of data "provides for normalization of abnormalities that occur in a single years operation with respect to each of the plants. This method will smooth out costs that are incurred for either significantly higher or significantly lower maintena[n]ce costs in any particular year and smooth[e]s out any effects that forced outages may have had on each of the plants." (Attachment 1, pp. 10-11.) The Commission agreed with MDU:

> Staff recommended using 67.4 percent to classify the energy–related portion of "Other Production Expense". The Commission rejects this recommendation. The Company determined this expense using a regression procedure on five years of costs. The Company's method mitigates the effect of single-year abnormalities and is superior to the staff recommendation.

(Attachment 2, p. 31.)

Although MDU's last electric rate order was over 15 years ago, the Commission continues to use historical averages to decide issues that are not predictable. In 1986 MDU argued for using a 5-year average and prevailed before the Commission. In this

case, the Staff made a similar argument using a 3-year average and prevailed before the Commission. Thus, Staff witnesses as well as MDU witnesses have testified now and in the past to the usefulness of averages to smooth out fluctuations that naturally occur from one year to the next.

In a more recent gas case before the Commission, MDU argued to include certain plant in service additions to its projected investment (rate base) in North Dakota. The Commission decided "to include an average level of historical additions in rate base rather than relying on the company's projections." (Attachment 3, p. 5.)

In the same case, MDU argued to increase its primary liability insurance expense by 112 percent while Staff argued for a four year average. The four year average was to smooth out fluctuations. (Attachment 3, p. 9.) The Commission agreed with Staff and used a four-year historical average. (Attachment 3, p. 8.)

In the above examples historical averages were not used to project wholesale margins. However, the past use of historical averages, as well as the reason for using historical averages, demonstrates the reasonableness of the Commission's decision to use historical averages in this case.

The reasonableness of the Commission's decision to use historical averages is also evidenced by the fact that commissions in other jurisdictions also use historical averages. For example, in 2000, the Pennsylvania Public Utility Commission agreed that a utilities off-system sales credit should be set at the average amount achieved during the last three years. The commission found that using the average of the last three years of off-system sales was a reasonable method to determine the credit. (Attachment 4, p. 8.)

Similarly, just last year the Texas Public Utility Commission found the use of an historical average to be reasonable. It held: "TXU Electric's use of a four-year average (1997-2000) of historical off-system sales upon which to project off-system sales for the Rate Year is reasonable." (Attachment 5, p.4.)

Also during 2001, the Hawaii Public Utilities Commission acknowledged the reasonableness of using a three-year historical average for purposes of projecting future cost recovery. "The use of a three-year period for purposes of projecting future cost recovery is consistent with the commission's past practice, and the use of the latest three-year period, as adjusted by the Consumer Advocate, is reasonable to ascertain a normalized trend." (Attachment 6, p. 128.)

And by way of just one more example, of which there could be many, the Kentucky Public Service Commission has recognized that known and measurable historical data is more reliable then planning studies of forecast. It stated: "While planning studies are a necessity as part of a utility's planning process, the results of such studies do not rise to the level of a known and measurable rate-making adjustment to a historical test period." (Attachment 7, p. 31.) The commission proceeded to make an adjustment based on the actual margin the utility experienced on off-system sales, explaining that such an adjustment "is supported by the evidence of record, does not rely on planning studies or forecast, and can be judged to be known and measurable." (Attachment 7, p. 32.)

The Commission's use of historical averages for other purposes in the present case, the use of which is not challenged by MDU, supports the reasonableness of the Commission's decision to project wholesale margins to the test year by use of the three-year historical average. The Commission used a three-year historical average to determine the appropriate level of bonuses and commissions for the 2002 test year. (Doc. 101, p. 10.) The Commission also used a three-year historical average to determine the fair and reasonable level of office supply expenses for the 2002 test year. (Doc. 101. p. 11.) MDU has not challenged the use of a three-year historical average in either of these contexts.

Finally, common sense and regular practice demonstrate the reasonableness of using historical averages to plan for the future. Both personally and professionally, many individuals use and average historical information (such as revenues, income, sales, etc.)

to project what will occur in the future. It was reasonable for the Commission to do the same.

This Court may not agree that the use of a three-year historical average is the best way to project wholesale margins to the 2002 test year. That is not the standard of review, however. This Court does not act as a super commission and substitute its judgment for that of the Commission. Rather, it exercises restraint and simply asks whether a "reasoning mind" could have reasonably determined that it was appropriate to project wholesale margins to the 2002 test year based on a three-year historical average. Based upon the evidence presented in this case, as well as the regular and accepted practice of using historical averages in utility cases, a reasoning mind could have concluded it was appropriate to use a three-year historical average. Accordingly, the Commission's finding of fact is supported by the preponderance of the evidence and must be upheld.

II. The Commission's Conclusion of Law is supported by its Finding of Fact.

MDU's challenge to the Commission's conclusions of law is inextricably intertwined with its argument that the Commission's use of a three-year historical average is not supported by the preponderance of the evidence. Because the Commission's use of a three-year historical average is supported by the preponderance of the evidence, the Commission's conclusion of law that MDU's existing electric rates yield excess revenues of $4.273 million per year is supported by its findings of fact.

III. The Commission's order is supported by the Conclusions of Law and Findings of Fact.

The Commission's order directing MDU to reduce its electric rate by $4.273 million per year is based upon its conclusion of law, which is supported by its findings of fact, that MDU's existing retail rates yielded excessive revenues of $4.273 million. Because the Commission's findings of fact are supported by the preponderance of the evidence, its conclusions of law are sustained by its findings of fact, and its April 24, 2002, Order is

supported by its conclusions of law, the Public Service Commission's April 24, 2002, Findings of Fact, Conclusions of Law and Order must be affirmed.[6]

CONCLUSION

For the above reasons, the North Dakota Public Service Commission respectfully requests that this Court affirm its April 24, 2002, Order.

Dated this 19th day of August, 2002.

State of North Dakota
Wayne Stenehjem
Attorney General

By: _____
Douglas A. Bahr
Assistant Attorney General
State Bar ID No. 04940
Office of Attorney General
500 North 9th Street
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Facsimile (701) 328-4300

Attorneys for Appellee.

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[6] If the Court concludes that the Commission's finding of fact is not supported by the preponderance of the evidence, the appropriate remedy is to remand this matter to the Commission so it can consider the evidence and make a new finding of fact based upon any guidance provided by this Court. In other words, if the Court determines the Commission erred by using a three-year historical average, it is not the responsibility of this Court to determine the best formula to project the off-system sales margin for the 2002 test year; that responsibility remains with the Commission.

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

Montana-Dakota Utilities Co.,

Appellant,

v.

North Dakota Public Service Commission

Appellee.

AFFIDAVIT OF SERVICE BY MAIL

Civil No. 08-02-C-01719

RECEIVED
AUG 22 2002
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PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

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

Kim R. Grenz being first duly sworn, deposes and says:

1. I swear and affirm upon penalty of perjury that the statements made in this affidavit are true and correct.

2. I am of legal age and on the 19th day of August, 2002, I served the attached **APPELLEE'S BRIEF** upon Montana-Dakota Utilities Co., by and through their attorney Daniel S. Kuntz, by placing true and correct copies thereof in an envelope addressed as follows:

Daniel S. Kuntz
Attorney at Law
P.O. Box 1695
Bismarck, ND 58502-1695

135 PU-399-01-186 Pages: 2
Affidavit of Service
by Public Service Commission by Doug Bahr, AG Attor
08/22/2002 C: Comm Legal PUD (3) Mike AG's Office

and depositing the same, with postage prepaid, in the United States mail at Bismarck, North Dakota.

Kim R. Grenz

Subscribed and sworn to before me
this 19th day of August, 2002.

Notary Public

JOLENE J. THIEL
Notary Public, State of North Dakota
My Commission Expires APRIL 5, 2005
STATE OF NORTH DAKOTA
NOTARY PUBLIC SEAL

e:\dixie\c\ba...

APPROVED
DATE: 8-2-02
KMF

MOTION

August 2, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission close the executive session held under the authority of N.D.C.C. §§ 44-04-19.1(4) and 44-04-19.2 for attorney consultation concerning legal strategies relating to the appeal as well as a settlement proposal by Montana-Dakota Utilities Co., and return to the open public meeting in Montana-Dakota Utilities Co.'s 2000 Electric Operation Annual Report, Case No PU-399-01-186, *Montana-Dakota Utilities Co. v. North Dakota Public Service Commission,* Civil No. 08-02-C-01719.

\\regulator\case mgmt\caselib\010186\motion to reopen meeting.doc

Motion to close executiv session & return
to open public meeting
by Public Service Commission

07/02/2002C: Comm Legal PUD (3) Mike AG's Office .

APPROVED
DATE: 8-2-02
KMF

MOTION

August 2, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission close the public meeting and go into executive session under the authority of N.D.C.C. §§ 44-04-19.1(4) and 44-04-19.2 for attorney consultation concerning legal strategies relating to the appeal as well as a settlement proposal by Montana-Dakota Utilities Co. in Montana-Dakota Utilities Co.'s 2000 Electric Operation Annual Report, Case No PU-399-01-186, *Montana-Dakota Utilities Co. v. North Dakota Public Service Commission,* Civil No. 08-02-C-01719.

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Motion to close public meeting & go into executive session
by Public Service Commission

07/02/2002C: Comm Legal PUD (3) Mike AG's Office .

ZUGER KIRMIS & SMITH

COUNSELORS AND ATTORNEYS AT LAW

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Patrick J. Ward*++^
Rebecca S. Thiem, P.C.**
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JUL - 3 2002
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

July 2, 2002

Ms. Debra Simenson, Clerk
Burleigh County District Court
514 East Thayer Avenue
Bismarck, ND 58501

Re: Montana-Dakota Utilities Co. v. North Dakota Public Service Commission
Case No. 08-02-C-01719

Dear Ms. Simenson:

Enclosed for filing in the above-referenced case are Brief of Appellant Montana-Dakota Utitilties Co. and an Affidavit of Personal Service.

Sincerely,

Karol A. Cossette, PLS

Karol A. Cossette, PLS
Secretary to Daniel S. Kuntz

Enclosures

c: Douglas Bahr
Illona Jeffcoat-Sacco

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Cover letter re Brief & Affidavit of Service
by Montana-Dakota Utilities Co., a Division of MDU Re
07/02/2002C: Comm Legal PUD (3) Mike AG's Office

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

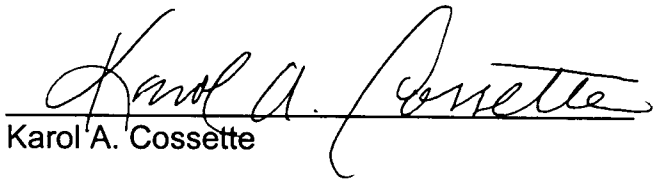
Appellee.

AFFIDAVIT OF PERSONAL SERVICE

The undersigned, being first duly sworn on oath, deposes and says that I am a United States citizen and on July 2, 2002, I hand-carried to the office of Assistant Attorney General Doug Bahr, Civil Litigation Division, 500 North 9th Street, Bismarck, ND, and personally served a copy upon those offices of the following:

Brief of Appellant Montana-Dakota Utilities Co.

Subscribed and sworn to before me, this 2nd day of July, 2002, a Notary Public for the County of Burleigh, State of North Dakota.
My Commission expires: 9/28/05



Karol A. Cossette

STATE OF NORTH DAKOTA — IN DISTRICT COURT

COUNTYOF BURLEIGH — SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,	)	
	)	**BRIEF OF APPELLANT**
Appellant,	)	**MONTANA-DAKOTA UTILITIES CO.**
	)	
-vs-	)	
	)	
North Dakota Public Service Commission,	)	
	)	
Appellee.	)	

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., ("MDU") submits the following brief in support of its appeal from an Order issued April 24, 2002 by the North Dakota Public Service Commission ("PSC" or "Commission") which directed MDU to reduce its North Dakota electric retail rates by an annual revenue amount of $4.273 million effective May 8, 2002.

ISSUES

1. **The Commission's finding of fact that it was "most appropriate" to project wholesale margins to the 2002 test year based on a three year historical average is not supported by the preponderance of the evidence.**

2. **The Commission's conclusion of law that MDU's existing electric rates yield excess annual revenues of $4.273 million is not supported by its findings of facts or a preponderance of the evidence.**

3. **The Commission's order directing MDU to file revised tariff sheets reflecting an across-the-board reduction of rates to produce a total net annual revenue decrease of $4.273 million is not in accordance with the law and is not supported by the findings of fact or by a preponderance of the evidence.**

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Brief of Appellant MDU
by Montana-Dakota Utilities Co., a Division of MDU R
07/02/2002C: Comm Legal PUD (3) Mike AG's Office

STATEMENT OF THE CASE

1. Nature of the Case.

This proceeding was initiated by a complaint filed by the Staff of the Public Service Commission ("Staff") seeking a reduction of MDU's retail electric rates in North Dakota. At the hearing on the complaint, the parties presented evidence based upon a 2002 "test year" regarding the net revenue needed by MDU to realize a reasonable rate of return on its utility investment used to provide electric service to its North Dakota customers. A major issue before the Commission was the level of net revenue that MDU would receive during the test year from wholesale electricity sales. Because of events that occurred in 1999 through early 2001, the margins on wholesale sales of electricity escalated to unprecedented levels during the first part of 2001 and then returned to more normal levels in the latter part of 2001. The Commission ignored unrefuted evidence that the recent high margins were an anomaly and would not reoccur during the test year. Instead, the Commission adopted a level of wholesale margins suggested by the Staff witness equal to the recent three-year average of high margins notwithstanding that the witness acknowledged the proposal was arbitrary and not reflective of current or foreseeable wholesale market conditions. This adjustment accounted for $3.475 million of the total $4.273 million rate reduction ordered by the Commission.

2. Course of Proceedings.

The Staff filed its complaint on September 7, 2001 seeking a reduction in MDU's retail electric rates. COR[1] 16. The hearing on the complaint was held February 25 and 26, 2002 in Bismarck. Following the submission of late-filed exhibits and post-hearing pleadings, the Commission issued its Findings of Fact, Conclusions of Law and Order on April 24, 2002. COR 101. The order directed MDU to implement an across-the-board rate reduction sufficient to produce an annual revenue decrease of $4.273 million. The rate reduction was to be effective for electric service rendered on and after May 8, 2002.

On April 25, 2002, MDU filed a Notice of Appeal and Specifications of Error along with an Undertaking and an Application for a Stay. COR 105-107. MDU's Application for a Stay was heard before the Court on May 2, 2002 and on the same day, the Court issued its Order staying that portion of the Commission's Order directing a reduction in MDU's rates in the amount of $3.475 million pending further order of the Court. MDU was directed to implement the remaining portion of the PSC's order by making an across-the-board reduction of rates to produce an annual revenue decrease of $798,000 effective May 8, 2002. MDU was further ordered to file a suspending bond in the amount of $3.475 million and to establish an interest bearing escrow account for the payment of the revenues collected by MDU in excess of the revenues that would have been collected under the rates ordered by the Commission.

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[1] Certificate of Public Service Commission record on appeal.

3. Utility Ratemaking Principles.

A public utility such as MDU is entitled to earn sufficient revenue that will allow it to meet its expenses and earn a fair and reasonable rate of return on its investment used to provide utility service to its customers. Montana-Dakota Utilities Co. v. Public Service Commission, 413 N.W.2d 308, 310 (N.D. 1987); Northern States Power Co., v. Public Service Commission, 73 N.D. 211, 13 N.W.2d 779 (N.D. 1944). The primary issue in a rate investigation is to determine if the rates complained of will yield a fair rate of return for a reasonable time in the immediate future. Application of Montana-Dakota Utilities Co., 102 N.W.2d 329, 341 (N.D. 1960). To determine if the utility's revenue is sufficient to meet operating expenses and a fair return on investment, a "test year" is used. Montana-Dakota Utilities Co. v. Public Service Commission, 413 N.W.2d at 310. Rates are set based on an estimate of revenues and expenses during the test year as adjusted for predictions of future trends and events that will affect the revenues and expenses. See, Detroit Edison Company v. Michigan Public Service Commission, 331 N.W.2d 159, 164 (Mich. 1982). In that regard, it is necessary to project revenues and expenses for the test year. Those projections, however, must be based upon the evidence. Application of Montana-Dakota Utilities Co., supra at 341-342. If the Commission determines the utility's existing rates are unreasonable based upon its review of the utility's net revenues for the test year, the Commission can establish new rates for the future. See, Montana-Dakota Utilities Co. v. Public Service Commission, 431 N.W.2d 276, 280 (N.D. 1988). The adequacy of the utility's revenues must relate to the period for which the revenues are being tested in order to reach a just result.

See, Application of Montana-Dakota Utilities Co., 102 N.W.2d 329, 335, citing Chicopee Manufacturing Co. v. Public Service Commission, 98 N.H. 5, 93 A.2d 820, 828 (1953).

Obviously, events occur during the period that rates are actually in effect causing revenues and expenses to be different than those projected for the test year. Weather extremes or unexpected economic activity are frequent examples of conditions that cause revenues and expenses to be different than those projected. When the costs are higher or the revenues lower than predicted, the utility earns a rate of return on its investment that is lower than anticipated; when the costs are lower or the revenues higher than predicted, the utility earns a rate of return on its investment that is higher than anticipated. When changed conditions cause inaccurate test year projections of revenues and expenses to continue, the Commission can prospectively revise the rates based upon a new test year in an effort to set more appropriate rates. See, Detroit Edison Company v. Michigan Public Service Commission, supra. The PSC has held that rates previously established by a Commission's order are presumed fair and reasonable until proven to the contrary. See, Application of Montana-Dakota Utilities Co., 111 N.W.2d 705, 708 (N.D. 1961).

When a party seeks a change of rates, the burden is on the party to show the existing level of rates is unfair and unreasonable. The moving party has the burden of going forward as well as the burden of persuasion in an administrative hearing. Bottineau County Resource District v. N.D. Wildlife Society, 424 N.W.2d 894 (N.D. 1988). If the evidence is insufficient to show the existing rates are unfair and unreasonable, the default in proof is attributable to the party that had the burden of proof. Id. at 342.

FACTS

MDU provides retail electric service to customers in North Dakota. Prior to this proceeding, MDU's retail electric rates in North Dakota were last set by the Commission in 1986. Tr. 19. From 1986-1996, MDU's electric earnings fluctuated and in some years its rate of return fell short of the level determined to be reasonable in 1986. Ex. 3 (COR 73); Tr. 19-20, 28, 143-144.

MDU's electric earnings are derived not only from sales of electricity to retail customers at the rates set by the PSC, but also from the sale of excess energy into the wholesale market such as to power brokers and other utilities. Ex. 6 (COR 48, p. 3). Unlike the price for retail electricity, wholesale prices are not regulated. Rather, buyers and sellers negotiate the quantity and price of wholesale sales based on existing market conditions. Accordingly, when MDU has electricity generating capacity available that is not needed by its retail customers, it attempts to sell electricity on the wholesale market if the price exceeds MDU's cost of fuel to produce the electricity. The "margin" between the wholesale price and MDU's fuel cost contributes to MDU's net revenue and reduces the amount of revenue needed from retail sales to provide a reasonable rate of return on MDU's utility investment.

Prior to 1997, the margin, or net revenue, from wholesale electricity sales made by MDU was relatively small at less than $2 million per year. The following are the annual margins MDU received from wholesale sales from 1996-2001:

Year	Sales (kwh)	Wholesale margin
1996	374,534,080	$ 1,915,866
1997	361,953,545	$ 2,491,993
1998	586,539,696	$ 4,816,728
1999	943,520,616	$ 8,772,849
2000	930,318,472	$ 9,918,345
2001	898,178,160	$15,937,892

See Ex. 3; Ex. 2, Schedule MRD-1.

Wholesale margins increased significantly in 1999 because a number of nuclear generating plants were shut down for extended periods for repair and maintenance. This reduced the amount of generating capacity and corresponding electricity supply available in the region. The reduced generating capacity, along with other economic conditions, enabled suppliers such as MDU to increase their level of wholesale sales. Tr. 281-282.

In the winter of 2000/2001, natural gas prices increased sharply to unprecedented levels. Because natural gas is a fuel source for a significant amount of electricity generation, the increase in natural gas prices led to an unprecedented increase in wholesale electricity prices. These increased prices dramatically increased MDU's electric wholesale margins even though the quantity of wholesale sales declined somewhat from 1999 through 2001. Tr. 282-283.

Natural gas prices fell in the second half of 2001 to more historic levels which continued through the hearing date. Correspondingly, the spot price of wholesale electricity retreated to historic levels. Notwithstanding the drop in prices in the second half of 2001, MDU was fortunate enough to have signed a wholesale contract with a buyer in March 2001 which provided for wholesale electricity sales through the summer

at the high prices that existed at the time the contract was signed. As a consequence, and despite the drop in spot wholesale electricity prices, MDU's margin from wholesale sales in 2001 reached $15.9 million, more than triple the level received only three years earlier. Tr. 348-349.

Based on MDU's level of earnings, realized in large part from wholesale electricity margins during 2000 and 2001, the Staff initiated a complaint seeking a decrease in MDU's retail electric rates. In its prefiled rebuttal testimony, the Staff recommended that the Commission project MDU's 2001 level of wholesale net revenue to the 2002 test year for purposes of setting future retail rates. Ex. 2, pp. 11-12 (COR 54). MDU's witnesses provided prefiled testimony stating that based on foreseeable market conditions, including actual sales during the last part of 2001 and the first two months of 2002, MDU's projected net revenues from wholesale sales would be $6.430 million during the 2002 test year. Ex. 7 (COR 59, p. 5).

At the hearing before the PSC, the Staff presented an alternative proposal for projecting wholesale margins for the 2002 test year using the average of the margins from 1999 to 2001 adjusted for demand penalties. Tr. 34-35. Under this proposal, the Staff suggested the Commission project wholesale margins of $11.696 million to the test year and reduce retail electric rates by $4.941 million annually. Ex. 3 (COR 73).

The PSC adopted the Staff's proposed three year historical average and directed MDU to reduce its North Dakota retail rates by $4.273 million.[2] The impact on rates from the projection of wholesale margins based upon the Staff's suggested three year

[2] The difference between the Staff's proposed rate reduction and the reduction ordered by the Commission is attributable to test year adjustments made by the PSC that are not at issue in this appeal.

historical average rather than MDU's estimate of such revenue was $3.475 million of the total $4.273 million reduction.

ARGUMENT

1. Standard of Review.

This is an appeal from an order of an administrative agency. See, N.D.C.C. §§ 28-32-01; 28-32-42; 49-05-12. The review of the factual basis of an administrative decision requires a three step process to determine: (1) if the findings of fact are supported by a preponderance of the evidence; (2) if the conclusions of law are sustained by the findings of fact; and (3) if the agency decision is supported by the conclusions of law. N.D.C.C. § 28-32-46; Griffin v. North Dakota Workers Compensation Bureau, 466 N.W.2d 148, 149 (N.D. 1991). In determining whether an agency's findings of fact are supported by a preponderance of the evidence, the standard of review is whether a reasoning mind could have reasonably determined that the agency's findings were proven by the weight of the evidence from the entire record. Theige v. North Dakota Workers Compensation Bureau, 1997 ND 160, 567 N.W.2d 337 (1997).

2. The Commission's finding of fact that it was "most appropriate" to project wholesale margins to the 2002 test year based on a three year historical average is not supported by the preponderance of the evidence.

The Staff prefiled direct written testimony of Mike Diller in support of its complaint in August 2001. Ex. 1, (COR 15). Mr. Diller is a certified public accountant who professes no expertise in wholesale electricity production, marketing or pricing. Id. at 3. In his testimony, Mr. Diller proposed the test year include net revenue for wholesale margins equal to the margins that MDU received in 2000, plus an adjustment to

represent the increase in the margins that occurred in early 2001. Id. at 27. Mr. Diller, however, provided no analysis of whether this or any other level of wholesale sales could be expected in 2002. Rather, the following is the only testimony he provided on this question:

> First, it is difficult to predict to what extent sales for resale will continue to grow. The historical growth of these sales suggests further adjustments could be made but the Staff has chosen to take a more conservative approach.

Id.

In other words, Mr. Diller simply assumed, based solely on historical trends, that wholesale margins would continue into the future without any underlying analysis to support his assumption.

MDU prefiled its direct written testimony on January 11, 2002. Ex. 6 (COR 45-50). C. Wayne Fox, President of MDU, testified the company's recent margins from wholesale sales were the result of a market anomaly and that the opportunity for such sales peaked in 2001 and would be significantly reduced in 2002 and beyond. Ex. 6 (COR 50, p. 6). Mr. Fox further testified that MDU will no longer be able to sell as much power in the wholesale market and what it does sell will not be at the high prices it saw in the last few years. Id. at 7.

The prefiled testimony of Terry L. Blinsky, who is the electric bulk power marketing coordinator for MDU, discussed current conditions in the wholesale power market and calculated a representative level of wholesale electricity sales given existing market conditions. Mr. Blinsky testified that MDU would not be able to market wholesale electricity at the levels experienced in the last few years. He specifically

discussed the factors that created the market anomaly allowing MDU to achieve the high level of wholesale margins in 2000 and 2001. One factor causing higher prices in the wholesale market was that a robust economy had driven an increased demand for electricity at the same time that construction of new generation facilities had been slowed for a number of years and simply did not keep pace with the increasing demand. Another factor was that natural gas prices were very high, particularly in the winter of 2000/2001 and continuing through the early part of the summer of 2001. High natural gas prices made gas-fired generation more expensive. Because MDU's generation is primarily coal-fired, it was able to enter into a number of transactions at very favorable margins. A third factor was that many wholesale purchasers of electricity were buying in the short-term market which resulted in price volatility. Ex. 6 (COR 48, pp. 1-4).

Mr. Blinsky testified that the wholesale market environment had drastically changed and the opportunity to make the higher wholesale margins no longer existed. First, demand for electricity had slowed in the face of a downturn in the general economy. Also, electricity supply had increased with a number of new generators coming on line. With supply and demand more nearly in balance, prices for sales into the wholesale market had fallen to normal levels and were expected to stay there. Natural gas prices had also dropped. Gas prices had fallen from about $9.00 per decatherm in early 2001 to $2.10 per decatherm. No one expected natural gas prices to return to the higher levels. The New York Mercantile Exchange ("NYMEX") gas futures prices remained under $3.80 per decatherm in every month through December 2007. This drop in natural gas prices made gas-fired generators much more

economical as an electricity supply source which severely cut into MDU's ability to make wholesale sales and particularly at the high prices achieved during recent years. Id. at 4-6.

These changes had a drastic impact on wholesale electric prices. The highest futures prices for electricity dropped from $142.50 per megawatt-hour (Mwh) in December of 2000 to $44.00 per Mwh in January 2002. Given current supply and demand conditions, Mr. Blinsky testified the high prices seen in the recent past were not likely to reoccur. Based upon existing market conditions, Mr. Blinsky projected that MDU would receive a margin of $7.247 million in 2002 assuming it could sell the same quantity of wholesale electricity that it sold in 2001 which Mr. Blinsky considered highly questionable in light of current conditions. Id. at 5-8.

Mr. Diller responded to MDU's testimony with rebuttal testimony filed on February 11, 2002. Ex. 2 (COR 54). Mr. Diller agreed the concerns raised by Mr. Blinsky can and do impact the supply and demand of electricity and therefore affect its price. Mr. Diller, however, found it difficult to determine the degree such concerns would have on future wholesale sales or the price of those sales. Id. at 8. Mr. Diller recognized the general downturn of the economy but didn't know whether to believe "some" who say the recession is over or "others" who say it hasn't occurred yet. Id. at 9. Diller agreed that natural gas prices affect the wholesale price of electricity but was puzzled that while natural gas prices declined steadily throughout 2001, MDU's resale margins did not reflect the price decline and reached new heights in 2001. He also acknowledged there were planned new additions of generation to the Mid-Continent Area Power Pool ("MAPP") that would outstrip projected growth in demand but stated

"some believe" recent events surrounding Enron tainted the energy market which "may very well" impact the number of generation plants built in the future. Id. at 10. Mr. Diller also had difficulty understanding the manner in which Mr. Blinsky calculated the projected margin of wholesale sales for 2002. Id. at 11. Notwithstanding Mr. Diller's acknowledgement of changed market conditions, he suggested that the wholesale margins projected for the test year be increased from his prior suggestion of $13.667 million to the 2001 margins of $15.938 million. Id. at 11-12. In other words, although Mr. Diller acknowledged changed conditions impacted wholesale electricity margins, he nonetheless suggested use of an unprecedented historical level of margins rather than attempt to determine a more appropriate level of margins based on the changed conditions.

MDU prefiled surrebuttal testimony on February 19, 2002 which included testimony addressing margins from wholesale sales of electricity. Ex. 7 (COR 56-63).

J. Steven Gaske, President of Zinder Companies, Inc. and an expert on utility finance and economics, submitted surrebuttal testimony addressing Mr. Diller's proposal to project 2002 test year wholesale margins based on 2001 wholesale margins rather than based on existing futures prices for electricity. Ex. 7 (COR 63). Mr. Gaske testified that the futures prices for electricity provide the best estimate of the prices that can be expected in the future. Id. at 21. Prices in the futures market, such as those used by Mr. Blinsky, " are a reliable, unbiased estimate of the market prices that will be available in the future and should be used for making test-year adjustments to the sales-for-resale price used to set Montana-Dakota's rates." Id. at 22. Mr. Gaske also testified that the factors that converged to create unusually high prices for

wholesale electric power in 2000 and 2001 were not likely to be present in the near future. Id. The U.S. economy which grew rapidly from 1997 to 2000 entered a recession during the second half of 2001 and continues to be shrinking. Id. Manufacturing production increased to very high levels in 2000 and 2001 but is projected to be at significantly lower levels in 2002. Id. at 22-23. The combination of reduced economic activity and new electric generation coming on line contributed to an expectation of greatly reduced energy prices during the next year. Id. at 23. In addition, natural gas prices declined so companies with coal-fired generation, such as MDU, that have been able to achieve exceptionally high margins on their wholesale electricity sales will no longer realize those margins in the future. Id. at 23-24. The average price of natural gas was projected to decrease to approximately $2.25 in 2002 which was lower than the average price of natural gas in any of the years 1998 to 2001. Id. at 24. Lower natural gas prices combined with new efficient gas-fired generation should cause a significant decline in wholesale electric prices in 2002. Id.

MDU also prefiled surrebuttal testimony of Roger Shiffman who is a principal consultant in the energy and water practice of Navigant Consulting, Inc., a national consulting firm specializing in the energy industry. Ex. 7 (COR 61). Mr. Shiffman's consulting group provides wholesale electricity price forecasts derived using detailed computer simulation models for all the regional power markets including the MAPP. Id. at 2. Mr. Shiffman addressed Mr. Diller's proposal that wholesale margins experienced in 2001 be projected to 2002 and beyond stating that "2001 was hardly a 'normal' or 'average' year in any respect, and conditions in both the natural gas and electricity wholesale markets changed in very significant ways throughout the year." Id. at 4. Mr.

Shiffman described the wholesale energy market in recent years. Beginning in the early to mid-1990's, demand growth for electricity outpaced the development of new generation supply. Id. at 8. Beginning in late 1997, several nuclear plants in the upper midwest region faced extended outages to repair cracks that had surfaced in steam generators. This resulted in extended outages of an unprecedented amount of midwest nuclear capacity during the summers of 1998 and 1999. Id. These outages led to significant price volatility during the summer months. Id. At their peak, reported wholesale prices reached $1,250 per Mwh in July, 1998 and $1,426 per Mwh in July, 1999 in the MAPP region. Id. at 9.

With the return to service of the nuclear capacity, and additional generation capacity coming into the market, price volatility returned to more normal levels during 2000. Id. Then, unprecedented increases in natural gas prices during the last quarter of 2000 and the first two quarters of 2001 resulted in significantly increased spot market electricity prices throughout the United States. Id. The correlation between MAPP electricity and natural gas prices has been increasing in recent years due to the increase in gas-fired generating capacity. Id. at 9-10. In addition, the electricity supply crisis in the western U.S. power markets, particularly in California, impacted electricity prices throughout the United States. Id. at 10.

Mr. Shiffman also addressed Mr. Diller's observation that MDU's wholesale margins were not immediately impacted in 2001 by the sharp decline in natural gas prices. Because MDU entered into a sales agreement in March 2001 which locked in summer electricity prices based upon futures prices in place in March, MDU enjoyed a higher margin from its contracting position than it would have earned selling power on

the spot market when natural gas and electricity prices declined during the last half of 2001. Id. at 11-12.

Mr. Shiffman described the price spikes that occurred in the winter of 2000/2001 as clearly an anomaly. Id. at 12. The price for off-peak electricity, which normally runs between $10 and $15 per Mwh reached slightly more than $47 per Mwh for the first time in recent history during the winter of 2000/2001. Id.

Market fundamentals for 2002 and subsequent near-term years suggest a period of improved stability in wholesale power markets. Id. at 15. Those market fundamentals included the return of natural gas prices to more normal levels, new electricity generating supply coming on line, reduced demand resulting from targeted conservation programs, and institutional electricity market reforms. Id. Mr. Shiffman testified that with more stable natural gas and electricity prices, profit margins on MDU's wholesale sales will be correspondingly lower. Id. at 16. Market conditions towards the end of 2001 were significantly more representative of what can be expected in 2002 and the foreseeable future. Id. at 17. Mr. Shiffman testified that the approach used by Mr. Blinsky for forecasting MDU's margins on wholesale sales using currently traded futures contracts was a reasonable approach to assess current market expectations during the relevant months of 2002. Id. at 17.

MDU also prefiled the surrebuttal testimony of Paul Wilkinson who is Vice President of Policy Analysis at the American Gas Association. Ex. 7 (COR 60). Mr. Wilkinson's responsibilities include analytical activities involving energy markets in general and natural gas markets in particular. Id. at 1. Mr. Wilkinson reviewed natural gas market conditions during the `90s, with prices of approximately $2.00 per mmbtu

during most of that period, in comparison to the extremely tight gas market during the winter of 2000/2001 which led to prices as high as $10.00 per mmbtu – by far the highest price level in a decade. Mr. Wilkinson described in detail the market conditions that resulted in the high prices as well as the subsequent dramatic retreat in gas prices following the 2000/2001 winter such that prices returned to the low $2.00 range. The natural gas market moved from a situation of high demand and low supply to one of low demand and high supply and the latter situation was expected to continue in 2002. Id. at 9. The U.S. Energy Information Administration projects that wellhead gas prices will be less than $2.00 per thousand cubic feet in 2002 and will range from $2.24 to $2.76 for 2003. Id. This was consistent with the futures gas prices on the NYMEX which were in the range of $2.00 to the low $3.00 range for all of 2002 and 2003. Id. These prices are in sharp contrast to the prices experienced in the 2000/2001 winter. Id. Between 2004 and 2010, Mr. Wilkinson expected natural gas prices to move within a band of $2.00 to $4.00 per mcf which is consistent with the long-term outlook of the Energy Information Administration and the NYMEX prices. Id. at 10. A reoccurrence of prices experienced during the 2000/2001 winter is unlikely. Id. Those market conditions were certainly not normal or representative of likely future market conditions. Id.

Terry L. Blinsky also submitted prefiled surrebuttal testimony on behalf of MDU that addressed Mr. Diller's observation that although natural gas prices declined in 2001, MDU's wholesale margins did not decline with the natural gas price decline. Ex. 7 (COR 59). Mr. Blinsky explained that because MDU was successful in entering into a contract with a buyer in March 2001 that covered the summer season of 2001 at prices

that existed when the contract was executed, MDU did not immediately realize the impact of the decline in spot market wholesale electricity prices until after the contract expired. Id. at 2-3. Absent this contractual arrangement, MDU would not have been able to maintain the margins it did in 2001. Id. at 2. For example, in June 2001, MDU sold electricity under the contract at $142.00 per Mwh in comparison to the price of $46.75 per Mwh MDU would have realized without the contract. Id. at 3. MDU did not have any contracts for wholesale electricity sales for the 2002 summer season. Id.

Mr. Blinsky testified that the wholesale market environment had drastically changed and MDU's opportunities to make higher wholesale margins no longer existed. Id. at 4. Reliance on historic results would significantly overstate the margins that MDU could expect in the future. Id. For example, MDU's January 2002 wholesale sales were 92,964 Mwh with a total margin of $622,000. Id. In comparison, MDU's January 2001 wholesale sales were 83,940 Mwh with a total margin of $1,316,000. Id. Even though more megawatt hours were sold in January 2002, the margin was lower by over 50%. Similar results could be expected in February. Id. at 4-5.

Mr. Blinsky updated his previous estimate of MDU's projected wholesale margins based upon current market conditions. Because prices had fallen even further since the initial preparation of Mr. Blinsky's estimate, his new projection of MDU's wholesale margins was $6,429,778. Id. at 5.

At the hearing before the Commission on February 25 and 26, 2002, each of the witnesses that had prefiled written testimony provided an oral summary of their testimony to the Commission. Mr. Diller's testimony included a Power Point presentation that was marked as Exhibit 3. Although he recognized the various factors

affecting the price of electricity, Mr. Diller made no attempt to analyze the impact of those factors on electricity prices during the 2002 test year. Instead, he made the curious statement that "I think the uncertainties of the future warrants the consideration of actual results as a proxy for future rates." Tr. 34. The suggestion to use historical results as a proxy for the future assumes, of course, that the conditions that led to the historical results are reasonably expected to reoccur in the future. Mr. Diller made no analysis of this assumption. In light of the uncontroverted testimony from MDU's witnesses that those conditions no longer existed and could not be expected to exist in the foreseeable future, there was no testimony or any other rational basis to support the use of recent historic results as a proxy for future prices.

Mr. Diller then suggested an alternative to his prior recommendation to project the 2001 wholesale margins to the 2002 test year. His alternative suggestion was that the Commission use an average of the wholesale margins for the past three years (1999-2001) for purposes of projecting wholesale margins to the 2002 test year. Tr. 34-35. Mr. Diller rationalized this suggestion by stating the rates established by the Commission "may be in effect for 15 years" and that "Using an average of recent results will smooth out recent market fluctuations and provide for a normalized level going forward." Tr. 34. Under this proposal, projected wholesale margins would be reduced from Mr. Diller's prior proposal of $15,937,892 to $11,695,641.

Mr. Diller's rationalization that rates might be in effect for 15 years was invalid because the Commission was required to determine net revenues for a 2002 test year and not attempt to determine whether those projections would still be valid 15 years into the future. Mr. Diller's rationalization was also contradictory because he was effectively

suggesting the Commission project a normalized level of margins going forward based upon an average of three years of abnormally high wholesale margins reflecting anything but normal market conditions. Mr. Diller's proposed three year average hardly represented a normalized level of wholesale margins even on a historic basis because the resulting average exceeded the annual level of wholesale margins that MDU had ever realized in any year with the exception of 2001.

Mr. Diller candidly acknowledged that his suggested use of a three year average was arbitrary:

> Q. [By Mr. Pearce]: What was the purpose for three? I mean, why not five to get a longer range analysis?
>
> A. I guess you could – you could go back ten years when there wasn't any resale margins, I guess, ten years ago, or none to speak of. To answer your question directly, it's just arbitrary. I don't think it would have made any difference to add another year because, let's see, 1998 resale margins were still high, but if you went back five years, it would change it a little bit.

Tr. 52.

Mr. Diller agreed the Commission should base its projections on the most recent information and trends available; however, he again stated his hope that the Commission could develop rates that will be in effect for the next fifteen years and that "I would not conclude that this is just for 2002." Tr. 55-56. Mr. Diller acknowledged that futures prices are "pretty accurate" as an indicator of price expectations a few months out, although they become a less accurate indicator the further out you get. Tr. 65.

MDU's witnesses summarized their prefiled direct and surrebuttal testimony that the margins realized in 2000/2001 were the result of a market anomaly that would not be repeated during the 2002 test year and beyond. Mr. Fox testified that MDU will no

longer be able to sell power in the wholesale market at the higher prices it saw in the last few years. Tr. 145. Mr. Gaske testified that recent economic information showed that industrial production, which was a major source of demand for electricity, had declined. Tr. 187. The forecast for manufacturing production is quite a bit lower than the average for the 2000 to 2001 time period and the country has been in a recession since the middle of 2001. Tr. 189.

Mr. Gaske also testified that the use of futures prices to forecast margins for the upcoming year is not a guess. Tr. 190. These are prices that electricity is actually selling for and will sell for during the future. Id. Futures prices are real market prices at which electricity can actually be sold and it's not the same thing as sitting down and trying to come up with a model to forecast. Id. Futures prices represent an unbiased estimate of what the market will be by both buyers and sellers in the market. Tr. 198. The futures prices at any given point in time reflect the best estimate of the market as to what it will do in the future. Tr. 226. For purposes of figuring out prices over the next year, the futures price is the best unbiased available evidence. Tr. 228, 235. Mr. Gaske analogized the forecasting of prices as similar to attempting to determine the price of MDU Resources stock. On one hand, you could use an econometric model and determine a valuation and predict the stock price, or on the other hand, you could look at the Wall Street Journal and see what the stock is actually trading at right now. Tr. 190. The use of futures prices by Mr. Blinsky should not be confused with the uncertainties and vagaries of forecasting because futures prices are real prices. Tr. 191.

Mr. Gaske also testified that gas prices were well below the unusual prices they reached during the 2000/2001 winter and were likely to continue at the lower levels. Tr. 193. Mr. Gaske summarized his testimony as follows:

> Various factors that contributed to the high margins in 2000 and 2001 are not likely and not forecast to continue in the upcoming year. In particular the ones that I was addressing had to do with the manufacturing production, which has an impact, the general overall economy, which is in recession, and natural gas prices, which are down, and in particular down relative to coal prices and in addition, I discussed the fact that futures prices are real prices in the sense that you could do a transaction right now with those prices to sell your power over the course of the next year at those prices.

Tr. 195-196.

Mr. Wilkinson testified that natural gas prices were in the low $2.00 range for several months prior to the hearing and that situation was expected to continue throughout 2002. Tr. 252. Given the state of the economy, weather conditions and gas supply, the surplus of natural gas was expected to carry into the 2002/2003 winter season, thus continuing downward pressure on gas prices. Tr. 253. Mr. Wilkinson testified that the price of natural gas is a very important factor affecting the amount of electricity that can sold into the wholesale market. Tr. 262.

Mr. Shiffman testified that the correlation between electricity in the MAPP region and natural gas prices has increased in recent years due to the fact that gas-fired generators in the MAPP region now occupy an expanding segment of the supply curve. Tr. 283. All the new electric generation that's coming into the market is gas-fired. Tr. 303. The contracting opportunities that were available to MDU in early 2001 are no longer available. Tr. 286. Current natural gas and electricity market fundamentals would not result in an expectation of repeated electricity price spikes and continued

abnormally high electricity wholesale margins. Tr. 289-290. A combination of factors point to lower and more stable wholesale electricity prices in the MAPP region for 2002 compared to the price volatility levels seen over the last four years particularly during the first half of 2001. Tr. 290-291. MDU will also face greater competition for wholesale sales. Tr. 291. The market conditions that existed toward the end of 2001 were significantly more representative of what could be expected in 2002 and the foreseeable future. Tr. 292. Mr. Shiffman testified that the Staff's proposal to use the average of the margins from 1999 to 2001 to project 2002 margins would overstate MDU's wholesale margins because the average would include the price volatility in 2000-2001 as well as the nuclear capacity outages that occurred earlier. Tr. 313-314.

Mr. Blinsky also testified that reliance on the historical averages would significantly overstate the margins that MDU can expect to make in the future. Tr. 352. Mr. Blinsky testified that if he updated his prior estimate with more recent prices from the Intercontinental Exchange, the estimated margin for MDU wholesale sales in 2002 would be $6,080,199. Tr. 356. The use of a three year sales average as proposed by Mr. Diller would result in the projection of wholesale margins that are "way too high." Tr. 361.

After the hearing MDU submitted an Affidavit of Terry Blinsky on April 16, 2002 that stated the actual quantity and margin of wholesale sales from January 1, 2002 through March 31, 2002. The actual sales during the first quarter of 2002 were 226,353 Mwh compared with 260,830 Mwh sold in the first quarter of 2002. The wholesale margins for the first quarter of 2001 were $1,618,840 compared to $4,126,072 for the first quarter of 2001. COR 95.

On April 24, 2002, the PSC issued its Findings of Fact, Conclusions of Law and Order. COR 101. Although the Commission labeled paragraphs 29-40 as findings of fact related to wholesale margins, paragraphs 29-39 are simply recitations of evidence and not findings of fact. The Commission's only findings of fact on this issue are contained at paragraph 40:

> 40. The Commission finds a high degree of uncertainty associated with predictions that are affected by one or more of at least 28 factors and the large number of combinations of those factors that are outside MDU or Commission control. These factors can change dramatically as evidenced by the change in prices of natural gas in recent years. We find that using the average of sales for resale during 1999, 2000, and 2001 is the most appropriate decision at this time.

There is no evidence to support a determination that the average of the resale margins from 1999 to 2001 is an appropriate indicator of the wholesale margins to be realized during the 2002 test year. Not only was the weight of the evidence overwhelming, it was unrefuted that:

1. The wholesale electricity market conditions of 2000-2001 were an anomaly with no expectation of reoccurrence in the foreseeable future. Although market conditions returned to more normal levels in the second half of 2001, MDU's 2001 wholesale earnings benefited from a contract it had entered into in March 2001 that extended through the summer of 2001 and allowed it to realize unprecedented wholesale margins in 2001.

2. Wholesale electricity prices are heavily influenced by the price of natural gas which spiked during the winter of 2000/2001. Natural gas prices have declined sharply and are not expected to increase in the foreseeable future. Natural gas has become a major fuel supply source for new electricity generation.

3. Economic conditions are in a downturn which results in reduced demand for electricity. This reduced demand is expected to continue through 2002.

4. Futures prices used by MDU to project its wholesale electricity margins for 2002 are the best unbiased estimate of what buyers and sellers expect prices to be.

5. MDU's margin from the sale of wholesale electricity during the first quarter of 2002 of $1,618,840 was less than 40% of its margin of $4,126,072 during the comparable period in 2001.

6. There was no evidence that any factor that might affect wholesale electricity margins as referenced in the PSC's finding of fact was expected to operate in a manner that would increase wholesale margins during the test year.

The Commission's finding of fact that the use of the average of MDU's 1999 to 2001 wholesale electricity margins was an appropriate projection of margins for the 2002 test year, rather than being supported by the preponderance of the evidence, was actually directly contrary to the preponderance of the evidence. Although Mr. Diller suggested such an average to project wholesale margins for the 2002 test year, he did not provide any opinion or other evidence, or even an expectation that this level of margins could be realized during the 2002 test year. Indeed, he acknowledged that the three year average was arbitrary and could just as well have been a five year or ten year average. The Commission's reliance upon a methodology that its own sponsor admits is arbitrary cannot be determined to be supported by the preponderance of the evidence.

The use of historical average to project margins in the future is only appropriate if the conditions that led to those historical margins are expected to reoccur. The evidence clearly established that the prices of 2000 and 2001 were the result of a market anomaly that would likely not occur in the foreseeable future and certainly not in the 2002 test year. Although simplistic in its approach, Mr. Diller's suggestion of using

a three year average to project future margins was flawed because it included the results from this unprecedented period that were not expected to occur in the test year. By including the extraordinary margins from the 2000/2001 time period in the historical average, Mr. Diller's proposal skewed the results so they were not even representative of historical market conditions and certainly not representative of market expectations during the 2002 test year. The flaw was further magnified by the arbitrary suggestion to use a three year average that incorporated this two year period of unprecedented high margins. Use of a longer period or even removal of the unrepresentative returns of 2001 would have yielded a result more consistent with normal conditions as well as more consistent with MDU's forecast. For example, if the Commission had averaged six years of margins from 1996 through 2001, a time period in which wholesale electricity sales had grown substantially, the result would have been $7.309 million in comparison to the three year average of $11.543 million. See, Attachment MRD-1 to Ex. 2 (COR 54). If the Commission had used the three year average of margins from 1997 through 1999 and thereby excluded the anomalous market conditions of 2000/2001, the average would have been $5,360,523, a number below MDU's projection. Id. No objective reasoning mind could have reasonably determined based upon the evidence that MDU would realize wholesale electricity margins during the 2002 test year of $11.5 million, particularly, when its actual margins through the first quarter of 2002 were $1.6 million.

Mr. Diller's support for the use of a three year average was apparently based on a belief that the resulting retail rates set by the Commission could remain in effect well beyond the test year. MDU, however, is not required to wait 15 years in the hope that

the stars will once again align for a repeat of the abnormal market conditions of 1999-2001 and provide MDU with the opportunity to earn a reasonable return on its utility investment. Utilities are entitled to have their rates set based upon known and measurable conditions as they exist or are expected to exist during the test year. North Dakota law specifically prohibits consideration of test year information or conditions more than 24 months after the date the new rate schedules are filed. N.D.C.C. § 49-05-04.1. Although conditions may occur that make the rates resulting from a rate proceeding reasonable for a period of time after the test year, it is not appropriate to speculate on events that may occur well beyond the test year for purposes of setting rates during the test year. In this case, the use of a three year average to project test year wholesale margins based upon a rationalization that unspecified events might occur 10-15 years into the future to make the margins reasonable is absolute speculation. Indeed, the three year average of wholesale margins has never been realized by MDU in any year other than 2001 which no one suggests represented normal or expected market conditions. The three year average bears no relation to any reasonable expectation of the future and is unsupported by any evidence that this level of sales could be realized during the test year. Similarly, the Commission's implied finding that some unspecified factor might operate at some unspecified time in the future to increase wholesale margins and thereby offset the impact of the known factors that were causing decreased margins, goes beyond speculation to imagination.

MDU recognizes that in dealing with issues of a highly technical nature, an administrative agency's expertise in the area is entitled to appreciable deference and that courts on appeal are reluctant to substitute their judgment for that of the

administrative agency on such matters. Montana-Dakota Utilities Co. v. Public Service Commission, 431 N.W.2d 276, 280 (N.D. 1988). In this case, however, the Commission exhibited no expertise in its finding of fact but, rather, simply accepted an admittedly arbitrary proposal submitted by its Staff. The Commission made no attempt to explain why a three year historical average was representative of expected electricity margins during the test year. Nor, could it make such an explanation since the evidence provided no basis for such an expectation. Nor did the Commission's speculation demonstrate any exercise of expertise.

It was the duty of the Commission to exercise its judgment to determine a reasonable wholesale electricity margin for the test year. In the exercise of that judgment, however, it could not disregard the evidence and substitute speculation and an arbitrary determination. Northern States Power Company v. Board of Railroad Commissioners, 298 N.W. 423, 434 (N.D. 1941). In the words of the North Dakota Supreme Court on a similar determination made by the PSC in a rate proceeding: "The variance between the unchallenged proof and the finding is too great to be accounted for as a reasonable exercise of the Commission's judgment." Id. Moreover, an agency's findings of fact must be adequate so the reviewing court can understand the basis for the agency's decision. Plenis v. North Dakota Workers Compensation Bureau, 472 N.W.2d 459 (N.D. 1991). The PSC finding of fact does not meet that adequacy requirement.

The PSC Staff had the burden or proof in this proceeding. There is no evidence supporting a finding that a three year historical average of wholesale electricity margins could reasonably be expected to be realized during the test year. A reasoning mind

could not reasonably determine that the weight of the evidence supported the Commission's finding that a three year historical average was appropriate for projecting wholesale electricity margins for the test year that would provide MDU with a reasonable opportunity to earn a reasonable rate of return on its utility investment. Transystems Services v. North Dakota Workers Compensation Bureau, 550 N.W.2d 66 (N.D. 1966).

3. The Commission's conclusion of law that MDU's existing electric rates yield excess revenues of $4.273 million per year is not supported by its findings of fact or a preponderance of the evidence.

Because the Commission improperly projected wholesale electricity margins based upon a three year historical average which was not supported by a preponderance of the evidence, its resulting conclusion of law that MDU's existing retail rates yield excessive revenues of $4.273 million is likewise not supported. All but $798,000 of the $4.273 million is attributable to the Commission's use of the three year historical average rather than the amount forecast by MDU based upon current futures prices.

4. The Commission's order directing MDU to file revised tariff sheets reflecting an across-the-board reduction to produce an annual revenue rate decrease of $4.273 million is not in accordance with the law and is not supported by the findings of fact or a preponderance of the evidence.

Because the Commission's order directing MDU to reduce its electric rates by $4.273 million is based upon the unsupported finding of fact to project wholesale electricity margins of $11.696 million to the test year, the order is not in accordance with the law. The order should be reversed and remanded with direction to the Commission to enter an order in accordance with the preponderance of the evidence.

CONCLUSION

The preponderance of the evidence does not support a projection of wholesale electricity margins for the test year of more than $6.430 million. MDU requests the Court to reverse the order of the Commission and remand the case to the Commission directing it to enter Findings of Fact, Conclusions of Law and an Order based upon a projection of wholesale electric margins in the test year of not more than $6.430 million.

Dated this 2nd day of July, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ID #03490)

Public Service Commission
State of North Dakota

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May 9, 2002

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dear Mr. Ball:

On May 8, 2002, the Commission approved Montana-Dakota Utilities Co.'s propane purchased gas adjustment for May 2002, Case No. PU-399-02-199, and the electric fuel cost adjustment for May 2002, Case No. PU-399-02-210.

The Commission also approved Montana-Dakota Utilities Co.s electric rates filed in compliance with the Commission's order in Case No. PU-399-01-186.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

Enclosure

130 **PU-399-01-186** Pages: 1

Letter to MDU re approval of compliance tariff
by Public Service Commission

05/09/2002C: Comm Legal PUD (3) Mike AG's Office .

APPROVED
DATE: 5-8-02
KMF

MOTION

May 8, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission approve, for service rendered on or after May 8, 2002, the electric rates filed in compliance with the Commission's Order in Montana-Dakota Utilities Co.'s 2000 Electric Operation Annual Report, Case No PU-399-01-186, and the Order of the District Court in *Montana-Dakota Utilities Co. v. North Dakota Public Service Commission,* Civil No. 08-02-C-01719.

JRL/sdh

129 **PU-399-01-186** Pages: 1
Motion approving compliance tariff
by Public Service Commission
05/08/2002C: Comm Legal PUD (3) Mike AG's Office .

ZUGER KIRMIS & SMITH

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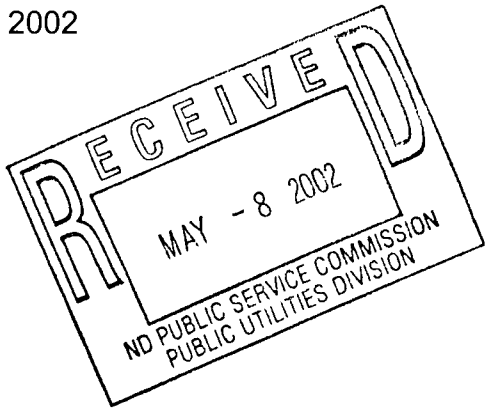
May 7, 2002



Ms. Illona Jeffcoat-Sacco
ND Public Service Commission
State Capitol -- 12th Floor
Bismarck, ND 58505-0480

Re: Supersedeas Bond for MDU Appeal

Dear Ms. Jeffcoat-Sacco:

This will confirm my telephone conversation with you and Mr. Bahr regarding the dollar limit on the supersedeas bond filed by MDU in support of its stay of the Commission's rate order issued on April 24, 2002 in case No. PU-399-01-186. MDU agrees that if the stay is still in effect when the escrowed funds collected by Montana-Dakota Utilities Co., plus interest, approach the dollar limit of the supersedeas bond, Montana-Dakota Utilities Co. will seek an increase in the limit of the supersedeas bond or the Public Service Commission may seek revocation of the stay, unless the parties reach an agreement otherwise. As indicated in the order granting the stay, Montana-Dakota Utilities Co. will be filing monthly reports showing the amounts collected pursuant to the stay and deposited in the escrow account.

Please contact me if you have any questions or need additional clarifications.

Sincerely,

Daniel S. Kuntz

c: Douglas Bahr
Don Ball
Doug Schulz

128 **PU-399-01-186** Pages: 1

Cover letter re filing

by Montana-Dakota Utilities Co., a Division of MDU Re

05/08/2002: Comm Legal PUD (3) Mike AG's Office

STATE OF NORTH DAKOTA

IN DISTRICT COURT

COUNTY OF BURLEIGH

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,	)	
	)	**ORDER APPROVING**
Appellant,	)	**SUPERSEDEAS BOND AND**
	)	**SCHEDULING ORDER**
-vs-	)	
	)	
North Dakota Public Service Commission,	)	
	)	
Appellee.	)	

Pursuant to the Court's Order for Stay dated May 2, 2002, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. ("MDU"), has submitted a Supersedeas Bond in the amount of $3,475,000 conditioned upon MDU's fulfillment of its obligation to refund all revenues which it collects in excess of the revenues it would have collected under the rates ordered by the North Dakota Public Service Commission if the Commission's Order had not been stayed by the Order of the Court dated May 2, 2002, and the Commission's Order is affirmed on appeal or the appeal dismissed on its merits or for lack of prosecution. The Court has reviewed the Supersedeas Bond and determines that it meets the requirements of North Dakota Century Code § 49-05-14.

NOW THEREFORE, the Supersedeas Bond submitted by MDU is approved and shall be filed with the Court.

At the hearing on MDU's Application for a Stay of the Commission's Order held on May 2, 2002, the parties agreed to the following scheduling order:

1. MDU shall file its brief on appeal within 40 days after the record of the North Dakota Public Service Commission is filed with the Court.

RECEIVED & FILED
MAY 07 2002
Clk. of Crt. Burleigh Co.

2. The North Dakota Public Service Commission shall file its Appellee's Brief within 30 days after service of MDU's brief.

3. MDU may file a Reply Brief within 15 days after service of the North Dakota Public Service Commission's Brief.

This appeal will be decided on the briefs unless the Court or either party request oral argument. A party requesting oral argument shall arrange for a time for the argument.

Dated this 7TH day of May, 2002.

BURT L. RISSELL

Judge of the District Court

Bond # 905–038–650

STATE OF NORTH DAKOTA

COUNTYOF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

SUPERSEDEAS BOND

1. An order was issued by the North Dakota Public Service Commission ("NDPSC") dated April 24, 2002 in NDPSC Case No. PU-399-01-186 ("Order"). The Order directs Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., ("MDU") to reduce its North Dakota electric retail rates by an annual revenue amount of $4,273,000 effective May 8, 2002.

2. MDU filed a timely notice of appeal of the Order to the District Court for the South Central Judicial District, Burleigh County, and seeks to stay that portion of the ordered reduction relating to the NDPSC's determination of the projected level of wholesale revenues. This portion of the reduction is $3,475,000.

3. MDU, and Liberty Mutual Insurance Company, as Surety, which has an office and place of business at Boston, Massachusetts, undertake and promise to pay up to $3,475,000 to the State of North Dakota for all damages caused by the delay in the enforcement of the Order and of all monies which any person, corporation, or limited liability company may be compelled to pay pending the appeal for retail electric

service in excess of the amount that would have been paid if the Order had not been stayed, and if:

a. The Order is affirmed or the appeal is dismissed on its merits or for lack of prosecution, and

b. MDU fails to refund all revenues which it collects in excess of the revenues that it would have collected under the rates ordered by the NDPSC if the Order had not been stayed.

If MDU fulfills the obligations on appeal set forth above, then this obligation shall be void. Otherwise, the obligations shall remain in full force and effect.

4. In no event, however, shall the Surety's maximum limit of liability exceed the penal sum of $3,475,000.

Dated this 7th day of May, 2002.

For the principal:

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.

Attest: Douglas W. Schulz
Douglas W. Schulz, Assistant Secretary

By C. Wayne Fox
C. Wayne Fox, President

DWS

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

On this 7 day of May, 2002, before me personally appeared C. Wayne Fox, known to me to be the ~~C. Wayne Fox President~~ of the corporation described in and which executed the within and foregoing instrument, and acknowledged to me that said corporation executed the same.

Subscribed and sworn to before me this 7 day of May, 2002, a Notary Public for the County of Burleigh, State of North Dakota. My Commission expires: March 9, 2005

Mary Brandt

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

For the surety: Liberty Mutual Insurance Company

Jacqueline L. Walls, Attorney-in-Fact

By: Jacqueline L Walls

Attest: Judi Dahl

COUNTY OF Burleigh)
)ss.
STATE OF North Dakota)

On this 6th day of May, 2002, before me personally appeared Jacqueline L. Walls, known to me to be the Attorney-in-Fact of the corporation described in and which executed the within and foregoing instrument, and acknowledged to me that said corporation executed the same.

Subscribed and sworn to before me this 6th day of May, 2002, a Notary Public for the County of Burleigh, State of North Dakota. My Commission expires: My commission expires March 30, 2006

Judi Dahl

Judi Dahl

THIS POWER OF ATTORNEY IS NOT VALID UNLESS IT IS PRINTED ON RED BACKGROUND. 919779

This Power of Attorney limits the acts of those named herein, and they have no authority to bind the Company except in the manner and to the extent herein stated.

LIBERTY MUTUAL INSURANCE COMPANY
BOSTON, MASSACHUSETTS

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS:

That Liberty Mutual Insurance Company (the "Company"), a Massachusetts mutual insurance company, pursuant to and by authority of the By-law and Authorization hereinafter set forth, does hereby name, constitute and appoint **ROLLIN C. MEHLHOFF, JACQUELINE L. WALLS, ALL OF THE CITY OF BISMARCK, STATE OF NORTH DAKOTA**.....

.....

.....

, each individually if there be more than one named, its true and lawful attorney-in-fact to make, execute, seal, acknowledge and deliver, for and on its behalf as surety and as its act and deed, any and all undertakings, bonds, recognizances and other surety obligations in the penal sum not exceeding _____ **FIFTY MILLION AND 00/100**********DOLLARS ($ **50,000,000.00**********) each, and the execution of such undertakings, bonds, recognizances and other surety obligations, in pursuance of these presents, shall be as binding upon the Company as if they had been duly signed by the president and attested by the secretary of the Company in their own proper persons.

That this power is made and executed pursuant to and by authority of the following By-law and Authorization:

ARTICLE XVI - Execution of Contracts: Section 5. Surety Bonds and Undertakings.
Any officer or other official of the company authorized for that purpose in writing by the chairman or the president, and subject to such limitations as the chairman or the president may prescribe, shall appoint such attorneys-in-fact, as may be necessary to act in behalf of the company to make, execute, seal, acknowledge and deliver as surety any and all undertakings, bonds, recognizances and other surety obligations. Such attorneys-in-fact, subject to the limitations set forth in their respective powers of attorney, shall have full power to bind the company by their signature and execution of any such instruments and to attach thereto the seal of the company. When so executed such instruments shall be as binding as if signed by the president and attested by the secretary.

By the following instrument the chairman or the president has authorized the officer or other official named therein to appoint attorneys-in-fact:

Pursuant to Article XVI, Section 5 of the By-laws, Timothy C. Mulloy, an official of Liberty Mutual Insurance Company, is hereby authorized to appoint such attorneys-in-fact as may be necessary to act in behalf of the company to make, execute, seal, acknowledge and deliver as surety any and all undertakings, bonds, recognizances and other surety obligations. All Powers of Attorney attested to or executed by Timothy C. Mulloy in his capacity as an officer or official of Liberty Mutual Insurance Company, whether before, on or after the date of this Authorization, including without limitation Powers of Attorney attested to or executed as Assistant Secretary of Liberty Mutual Insurance Company, are hereby ratified and approved.

That the By-law and the Authorization set forth above are true copies thereof and are now in full force and effect.

IN WITNESS WHEREOF, this Power of Attorney has been subscribed by an authorized officer or official of the Company and the corporate seal of Liberty Mutual Insurance Company has been affixed thereto in Plymouth Meeting, Pennsylvania this 26th day of December, 2001.

LIBERTY MUTUAL INSURANCE COMPANY

By _____
Timothy C. Mulloy, Assistant Secretary

COMMONWEALTH OF PENNSYLVANIA ss
COUNTY OF MONTGOMERY

On this 26th day of December, 2001, before me, a Notary Public, personally came Timothy C. Mulloy, to me known, and acknowledged that he is an official of Liberty Mutual Insurance Company; that he knows the seal of said corporation; and that he executed the above Power of Attorney and affixed the corporate seal of Liberty Mutual Insurance Company thereto with the authority and at the direction of said corporation.

IN TESTIMONY WHEREOF, I have hereunto subscribed my name and affixed my notarial seal at Plymouth Meeting, Pennsylvania, on the day and year first above written.

TERESA PASTELLA NOTARY PUBLIC COMMONWEALTH OF PENNSYLVANIA

_____
Notary Public

CERTIFICATE

I, the undersigned, Assistant Secretary of Liberty Mutual Insurance Company, do hereby certify that the original power of attorney of which the foregoing is a full, true and correct copy, is in full force and effect on the date of this certificate; and I do further certify that the officer or official who executed the said power of attorney was one of the officers or officials specially authorized by the chairman or the president to appoint attorneys-in-fact as provided in Article XVI, Section 5 of the By-laws of Liberty Mutual Insurance Company.

This certificate and the above power of attorney may be signed by facsimile or mechanically reproduced signatures under and by authority of the following vote of the board of directors of Liberty Mutual Insurance Company at a meeting duly called and held on the 12th day of March, 1980.

VOTED that the facsimile or mechanically reproduced signature of any assistant secretary of the company, wherever appearing upon a certified copy of any power of attorney issued by the company in connection with surety bonds, shall be valid and binding upon the company with the same force and effect as though manually affixed.

IN TESTIMONY WHEREOF, I have hereunto subscribed my name and affixed the corporate seal of the said company, this 6th day of May, 2002.

_____
John F. X. Hee, Assistant Secretary

Not valid for mortgage, note, loan, letter of credit, bank deposit, currency rate, interest rate or residual value guarantees.

To confirm the validity of this Power of Attorney call 1-610-832-8240 between 9:00 am and 4:30 pm EST on any business day.

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

AFFIDAVIT OF MAILING

STATE OF NORTH DAKOTA)
) ss
COUNTY OF BURLEIGH)

The undersigned, being duly sworn, deposes and says that I am a United States citizen, over 18 years of age, and on May 7, 2002, I served a copy of the attached:

ORDER APPROVING SUPERSEDEAS BOND; SUPERSEDEAS BOND

by placing a true copy in a postage paid envelope addressed to each person named below, at the address stated below, which is the last known address of the addressee, and by depositing said envelope in the United States mail at Bismarck, North Dakota.

Doug Bahr
Assistant Attorney General
Department 125
900 East Boulevard
Bismarck, ND 58505-0041

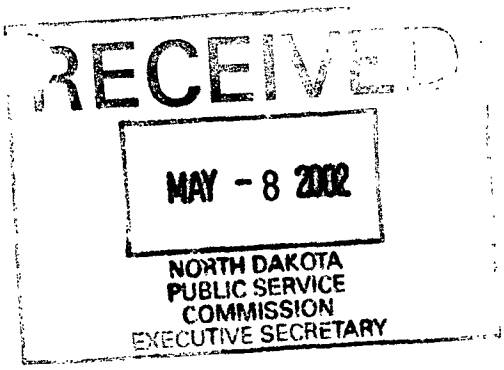
125 PU-399-01-186 Pages: 2
Affidavit of Mailing
by Montana-Dakota Utilities Co., a Division of MDU R
05/08/2002C: Comm Legal PUD (3) Mike AG's Office

Karol A. Cossette

Karol A. Cossette

Subscribed and sworn to before me May 7, 2002, a Notary Public for the County of Burleigh, State of North Dakota. My Commission expires: 9-5-04

Valerie A. Leopold



ACKNOWLEDGMENT OF FILING

Receipt of the foregoing described copies of documents on file in the Public Service Commission in **PSC Case No. PU-399-01-186 (Civil Case No. 08-02-C-01719)** is hereby acknowledged at Bismarck, North Dakota this 6th, day of May, 2002.

Sharalynn Mills, deputy
Clerk of District Court
Burleigh County

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Acknowledgment of filing

by Burleigh County District Court

05/08/2002C: Comm Legal PUD (3) Mike AG's Office

STATE OF NORTH DAKOTA

COUNTYOF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

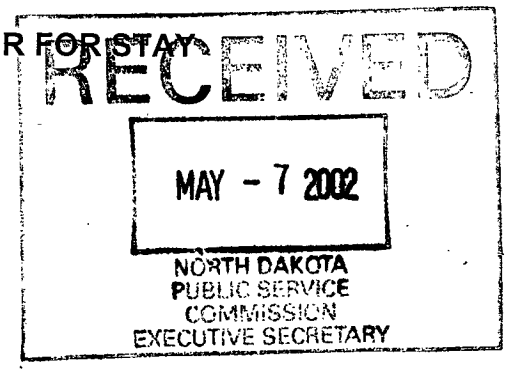
Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

ORDER FOR STAY



This matter comes before the Court on the application of Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., ("MDU") for a stay of an order issued by the North Dakota Public Service Commission ("NDPSC") dated April 24, 2002 in NDPSC Case No. PU-399-01-186. The order directs MDU to reduce its North Dakota electric retail rates by an annual revenue amount of $4.273 million effective May 8, 2002.

By its application, MDU requests the Court to stay the operation of the NDPSC's order pending a final order of the Court on MDU's appeal. Alternatively, MDU requests a stay of that portion of the ordered reduction relating to the NDPSC's determination of the projected level of wholesale revenues which is the subject of MDU's appeal. The portion of the reduction relating to the issue on appeal is $3.475 million.

The application was heard before the Court on May 2, 2002. MDU and the NDPSC were represented by their respective counsel. The NDPSC does not object to MDU's alternative request to stay only the portion of the NDPSC's order relating to the

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Clk. of Crt. Burleigh Co.

issue on appeal subject to MDU's compliance with the requirements of N.D.C.C. § 49-05-14.

IT IS ORDERED,

1. The portion of the order of the NDPSC in Case No. PU-399-01-186 directing a reduction in MDU's North Dakota electric retail rates in the amount of $3.475 million is stayed pending further order of the Court;

2. MDU shall implement the remaining portion of the NDPSC's order by making an across-the-board reduction of its North Dakota electric retail rates sufficient to produce an annual revenue decrease of $798,000 effective May 8, 2002.

3. MDU shall file a suspending bond in the amount of $3.475 million as a condition to the effectiveness of this order.

4. MDU shall establish an interest bearing escrow account at a bank or trust company authorized to do business in North Dakota. MDU shall pay into the escrow account the revenues collected by MDU in excess of the revenues that would have been collected under the rates ordered by the NDPSC in Case No. PU-399-01-186. MDU shall file a report monthly with the NDPSC showing the amounts paid into the escrow account and the manner in which such amounts were determined.

Dated this 2nd day of May, 2002.

Burt L. Riskedahl
Judge of the District Court

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 6, 2002

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MAY - 6 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Ms. Debra Simenson, Clerk
Burleigh County District Court
P. O. Box 1055
Bismarck, ND 58502-1055

Re: Civil No. 08-02-C-01719
Montana-Dakota Utilities Co., Appellant, vs
North Dakota Public Service Commission, Appellee.
PSC Case No. PU-399-01-186

Dear Ms. Simenson:

Enclosed for filing in Civil No. 08-02-C-01719 please find the originals of the **Certificate of Record on Appeal**, **Notice to Appellant of Actual Costs and Affidavit of Mailing.**

I am also enclosing an Acknowledgment of Filing and a stamped self-addressed envelope for your use.

If you have any questions, please call. Thank you.

Sincerely,

William W. Binek
Special Assistant Attorney General

WWBsls
Enclosure

c: Daniel S. Kuntz
Doug Bahr

122 **PU-399-01-186** Pages: 1

Cover letter to Clerk of Court re filings

by Public Service Commission

05/06/2002C: Comm Legal PUD (3) Mike AG's Office .

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

Montana-Dakota Utilities Co.,
Appellant,

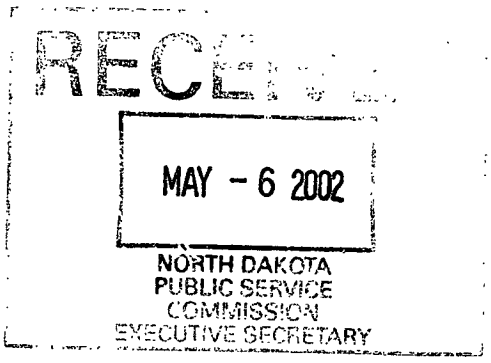
v.

North Dakota Public Service Commission,

Appellee.

PSC Case No. PU-399-01-186

CIVIL NO. 08-02-C-01719
CERTIFICATE OF RECORD
ON APPEAL



TO: **Ms. Debra Simenson**
Clerk of District Court
Burleigh County District Court
P. O. Box 1055
Bismarck, ND 58502-0155

I, Jon H. Mielke, Executive Secretary, of the North Dakota Public Service Commission (Commission), do hereby certify that the papers and documents marked with an asterisk (" * ") on the attached docket card constitute true and correct photocopies of documents contained in the record of the captioned matter on file in the offices of the Public Service Commission in **Case No. PU-399-01-186.**

IN WITNESS WHEREOF I have set my hand and affixed the seal of the Public Service Commission of the State of North Dakota.

Dated at Bismarck, North Dakota, **May 6, 2002.**

Jon H. Mielke
Executive Secretary
Public Service Commission
State of North Dakota
600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
701/328-2400

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Certificate of Record on Appeal

by Public Service Commission

05/06/2002C: Comm Legal PUD (3) Mike AG's Office

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	1	4/16/2001	**Report** By Montana-Dakota Utilities Co., a Division of MDU Re	12
*	2	5/4/2001	**Memo to Commission re Annual Report** By Public Service Commission	2
*	3	5/4/2001	**Letter to MDU re annual report** By Mike Diller Public Service Commission	1
	4	5/4/2001	**Affidavit of Service by Ordinary Mail** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\4.doc	1
	5	5/17/2001	**Contract #PU-425-01 issued to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\5.doc	4
	6	5/17/2001	**Mtn approved to execute an $8000 contract w/Snavely King Majoros O'Connor & L** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\6.doc	1
*	7	5/17/2001	**Motion appointing Diller & Binek as advocacy staff** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\7.doc	1
	8	5/17/2001	**Cover letter re contract for consulting services** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\8.doc	1
*	9	5/23/2001	**Signed Contract No. PU-425-01** By Snavely King Majoros O'Connor & Lee, Inc.	6
	10	7/11/2001	**Contract No. PU-427-01 issued to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission	4
*	11	7/11/2001	**Motion to execute contract to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\11.doc	1
	12	7/11/2001	**Letter to consultant re Contract** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\12.doc	1
*	13	7/20/2001	**Signed Contract No. PU-427-01** By Snavely King Majoros O'Connor & Lee, Inc.	5
*	14	9/7/2001	**Direct Testimony of Charles W King** Exhibit : 4 By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\14.doc	96
*	15	9/7/2001	**Direct Testimony of Mike Diller** Exhibit : 1 By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\15.doc	40
*	16	9/7/2001	**Complaint** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\16.doc	3
*	17	9/7/2001	**Cover letter re Complaint** By Mike Diller, Director of Accounting Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\17.doc	1
*	18	9/19/2001	**Motion appointing Lein as advocacy staff / Illona & Fahn as Commission advisors** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\18.doc	1
*	19	9/19/2001	**Motion - Complaint states a prima facie case & serve complaint on MDU** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\19.doc	1

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	20	9/21/2001	**Affidavit of Service to serve Complaint on MDU**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\20.doc	
*	21	10/9/2001	**Answer**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	4
*	22	10/18/2001	**Errata to Staff's Testimony**	
			By Mike Diller Public Service Commission	4
	23	10/18/2001	**Affidavit of Service**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\23.doc	
*	24	11/5/2001	**Letter re off-system sales**	
			By Comm. Wefald Public Service Commission	6
*	25	11/14/2001	**Letter confirming procedural schedule**	
			By William P. Pearce, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	2
*	26	11/21/2001	**Response To Comm. Wefald's letter**	
			By Mike Diller Public Service Commission	4
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\26.doc	
	27	11/21/2001	**Affidavit of Service**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\27.doc	
*	28	11/21/2001	**Notice of Hearing, Notice of Public Input Sesions & Notice of Intervention**	
			By Public Service Commission	2
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\28.doc	
*	29	11/21/2001	**Motion**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\OrderLib\2001\010186\29.doc	
	30	11/23/2001	**Notice e-mailed to NDNA requesting publication**	
			By Public Service Commission	2
	31	11/23/2001	**Affidavits of Service**	
			By Public Service Commission	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\31.doc	
*	32	11/27/2001	**Request for ALJ for Feb. 25th Hearing**	
			By Public Service Commission	2
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\32.doc	
*	33	11/29/2001	**Allen Hoberg appointed ALJ**	
			By Office of Administrative Hearings	1
	34	12/3/2001	**Videoconference Confirmation**	
			By North Dakota Interactive Video Network	1
*	35	12/4/2001	**Response to Commissioner Wefald's Nov. 5th letter**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2
	36	12/13/2001	**Affidavit of Publication**	
			By Golden Valley News	1
	37	12/9/2001	**Display ad for Public Input Session**	
			By Bismarck Tribune	1
	38	12/20/2001	**Affidavit of Publication**	
			By North Dakota Advertising Service, Inc.	1

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2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
	39	1/3/2001	**Letter to MDU re request for court reporter**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\39.doc	
	40	1/4/2002	**Affidavit of Publication & clippings**	
			By Williston Daily Herald	5
	41	1/8/2002	**Publication billing for display ad**	
			By Dickinson Press & The Advertizer	3
	42	1/9/2002	**Request for a court reporter to be present at hearing**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**43**	1/9/2002	**Court reporter ordered for 2/25/02 hearing**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\43.doc	
	44	1/9/2002	**Affidavit of Publication**	
			By Bismarck Tribune	3
*	**45**	1/11/2002	**Direct Testimony of Rita A Mulkern**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**46**	1/11/2002	**Direct Testimony of Donald R Ball**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	8
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**47**	1/11/2002	**Direct Testimony of Gerald L Gress**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**48**	1/11/2001	**Direct Testimony of Terry L Blinsky**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	11
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**49**	1/11/2002	**Direct Testimony of J Stephen Gaske**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	65
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**50**	1/11/2002	**Direct Testimony of C Wayne Fox**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	9
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	**51**	1/11/2002	**Cover letter re direct testimony**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
	52	1/24/2002	**Affidavit of Publication**	
			By Adams County Record	1
*	**53**	2/11/2002	**Rebuttal Testimony of Charles W King**	
		Exhibit : 5	By Snavely King Majoros O'Connor & Lee, Inc.	19
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\53.doc	
*	**54**	2/11/2002	**Rebuttal Testimony of Mike Diller**	
		Exhibit : 2	By Mike Diller Public Service Commission	23
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\54.doc	
*	**55**	2/11/2002	**Cover letter re Staff's Rebuttal Testimony**	
			By Mike Diller Public Service Commission	1
*	**56**	2/19/2002	**Surrebuttal Testimony of Rita A Mulkern**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	5
*	**57**	2/19/2002	**Surrebuttal Testimony of Donald R Ball**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	9

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	**58**	2/19/2002	**Surrebuttal Testimony of Richard A Espeland**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	7
*	**59**	2/19/2002	**Surrebuttal Testimony of Terry L Blinsky**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	10
*	**60**	2/19/2002	**Surrebuttal Testimony of Paul L. Wilkinson**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	11
*	**61**	2/19/2002	**Surrebuttal Testimony of Roger Joseph Schiffman**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	28
*	**62**	2/19/2002	**Surrebuttal Testimony of Douglass A. Mahowald**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	7
*	**63**	2/19/2002	**Surrebuttal Testimony of J. Stephen Gaske**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	30
*	**64**	2/19/2002	**Cover Letter re Surrebuttal Testimony**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**65**	3/1/2002	**Exhibit List from Feb, 25 & 26, 2002 Hearing**	
			By Office of Administrative Hearings	2
*	**66**	3/1/2002	**Letter closing ALJ's file**	
			By Office of Administrative Hearings	1
*	**67**	3/5/2002	**Details of the change in Account 920/salary changes**	
		xhibit : Late Filed 20	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	**68**	3/5/2002	**Details of fixed costs of aircraft**	
		xhibit : Late Filed 19	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**69**	3/5/2002	**Details on Update Exhibit No. (DRB-2) to include insurance premium expense**	
		xhibit : Late Filed 18	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	**70**	3/5/2002	**Details on changes in Account 921 from 2000 to 2001**	
		xhibit : Late Filed 17	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	**71**	3/5/2002	**Details on monthly on-peak & off-peak prices for MAPP (1998-2001)**	
		xhibit : Late Filed 16	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	**72**	3/5/2002	**Cover letter re Late Filed Exhibits 16 - 20**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**73**	2/25/2002	**PSC Staff Presentation**	
		Exhibit : 3	By Public Service Commission	35
*	**74**	2/25/2002	**Response to Data Request No. 5**	
		Exhibit : 8	By Montana-Dakota Utilities Co., a Division of MDU Re	3
*	**75**	2/25/2002	**Table 1, Prices & Intercontinental Exchange Forward Electricity Prices**	
		Exhibit : 9	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**76**	2/25/2002	**MDU Pool Sales Calculation**	
		Exhibit : 10	By Montana-Dakota Utilities Co., a Division of MDU Re	1

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	77	2/25/2002	**Reliability Assessment, 2001-2010**	
		Exhibit : 11	By Montana-Dakota Utilities Co., a Division of MDU Re	3
*	78	2/25/2002	**Selected gas utilities companies data for most recent calendar year**	
		Exhibit : 12	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	79	2/25/2002	**MAPP 2001 update to the 2000 regional plan**	
		Exhibit : 13	By Montana-Dakota Utilities Co., a Division of MDU Re	41
*	80	2/25/2002	**Public Utilities Reports, Advance Sheets**	
		Exhibit : 14	By Montana-Dakota Utilities Co., a Division of MDU Re	9
*	81	2/26/2002	**Table 1, Completed & Sited New Power Plants in MAPP**	
		Exhibit : 15	By Montana-Dakota Utilities Co., a Division of MDU Re	6
*	82	3/13/2002	**Original - Transcript of Hearing Volume I taken 2/25/02**	
			By Emineth & Associates Court Reporters	0
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\84.doc	
*	83	3/13/2002	**Original - Transcript of Hearing Volume II taken 2/26/02**	
			By Emineth & Associates Court Reporters	0
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\85.doc	
	84	3/13/2002	**Copy - Transcript of Hearing Volume I taken 2/25/02 & diskette**	
			By Emineth & Associates Court Reporters	0
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\84.doc	
	85	3/13/2002	**Copy - Transcript of Hearing Volume II taken 2/26/02**	
			By Emineth & Associates Court Reporters	0
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\85.doc	
	86	3/28/2002	**Letter to consulting service re closing out consulting contract**	
			By Mike Diller Public Service Commission	1
*	87	4/2/2002	**Proposed Findings of Fact, Conclusions of Law and Order**	
			By Public Service Commission	15
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\87.doc	
*	88	4/2/2002	**Cover letter re Proposed Findings**	
			By Public Service Commission	1
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\88.doc	
*	89	4/2/2002	**Brief of Montana-Dakota Utilities Co.**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	14
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\89.doc	
*	90	4/2/2002	**Proposed Finding of Fact, Conclusions of Law and Order**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	11
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\90.doc	
*	91	4/2/2002	**Cover letter re filings**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	1
*	92	4/4/2002	**Staff Response to Brief of MDU**	
			By Public Service Commission	10
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\92.doc	
*	93	4/4/2002	**Cover letter re Staff Response to Brief of MDU**	
			By Wm. Binek Public Service Commission	1
		\\Regulator\Case Mgmt\OrderLib\2001\010186\	\\Regulator\Case Mgmt\Orderlib\2001\010186\93.doc	
*	94	4/10/2002	**Additional information on summary of A&G salaries**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	95	4/16/2002	**Affidavit of Tery L Blinsky**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	96	4/16/2002	**Request for case to be held open for purposes of settlement negotiations** By William P Pearce, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	1
*	97	4/18/2002	**Commission Advocacy Staff's response to Terry L Blinsky's Affidavit** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\97.doc	1
*	98	4/22/2002	**Letter notifying Commission of termination of settlement negotiations** By Wm. Binek Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\98.doc	1
*	99	4/24/2002	**Concurring Opinion by Commissioner Clark** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	2
*	100	4/24/2002	**Concurring Opinion by Commissioner Wefald** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	1
*	101	4/24/2002	**Findings of Fact, Conclusions of Law and Order** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	16
*	102	4/24/2002	**Motion** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\102.doc	1
	103	4/26/2002	**Affidavits of Service** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\103.doc	5
	104	4/25/2002	**Notice of Motion on Application for a Stay** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	1
	105	4/25/2002	**Application for Stay and Brief in Support Thereof** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	29
	106	4/25/2002	**Undertaking on Appeal to District Court** By Montana-Dakota Utilities Co., a Division of MDU Re	1
	107	4/25/2002	**Notice of Appeal and Specifications of Error - Civil No. 08-02-C-01719** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	2
	108	4/29/2002	**Amended Notice of Motion on Application for a Stay** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	3
	109	4/29/2002	**Affidavit of Personal Service** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	1
	110	4/30/2002	**Affidavit of Service** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\111.doc	2
	111	4/30/2002	**Notice to Appellant of Estimated Costs** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\111.doc	8
	112	4/30/2002	**Letter to Clerk of Court re filig of Notice of Estimated Costs** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\111.doc	1
*	113	5/1/2002	**Motion** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\113.doc	1
*	114	5/2/2002	**Compliance Tariffs** By Montana-Dakota Utilities Co., a Division of MDU Re	53

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	**115**	5/3/2002	**Estimated costs of preparing record for court received ($129.83)**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	**116**	5/3/2002	**Affidavit of Service by First Class Mail**	
			By Public Service Commission	1
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\117.doc	
*	**117**	5/3/2002	**Staff Response to Compliance Filing**	
			By Public Service Commission	1
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\117.doc	
*	**118**	5/3/2002	**Cover Letter re filing**	
			By William W. Binek, Chief Counsel Public Service Commission	1
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\117.doc	

Total Pages: 802
Certified Pages: 708

ACKNOWLEDGMENT OF FILING

Receipt of the foregoing described copies of documents on file in the Public Service Commission in **PSC Case No. PU-399-01-186 (Civil Case No. 08-02-C-01719)** is hereby acknowledged at Bismarck, North Dakota this _____, day of May, 2002.

_____

Clerk of District Court
Burleigh County

STATE OF NORTH DAKOTA

IN DISTRICT COURT

COUNTY OF BURLEIGH

SOUTH CENTRAL JUDICIAL DISTRICT

Montana-Dakota Utilities Co.,
Appellant,

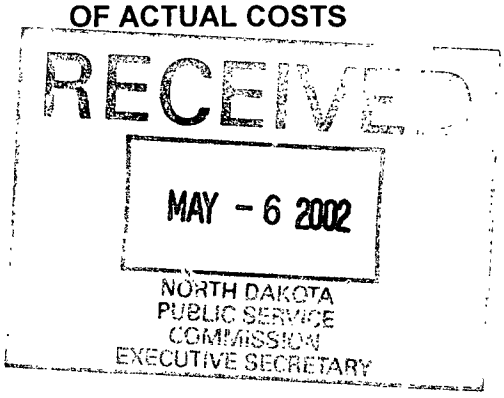
v.

North Dakota Public Service Commission,

Appellee.

PSC Case No. PU-399-01-186

CIVIL NO. 08-02-C-01719
NOTICE TO APPELLANT OF ACTUAL COSTS



TO: Daniel S. Kuntz, Zuger Kirmis & Smith, P. O. Box 1695, Bismarck, ND 58502-1695, **Attorneys for Appellee Montana-Dakota Utilities Co.**

Under N.D.C.C. § 28-32-17 (2) when a Public Service Commission decision is appealed, the Public Service Commission must notify the appellant of the estimated costs of preparing and filing the record. The appellant must then pay the Public Service Commission the amount estimated. If the actual costs are more than the estimated costs, the appellant must pay the difference. If the actual costs are less than the estimated costs, the Public Service Commission will refund the difference.

PLEASE TAKE NOTICE that the total actual costs for preparing and filing the record in the captioned matter are as set forth below:

Copies	$71.15
Compilation Time	$58.68
Total Costs	**$129.83**
Costs Paid by Appellant	$129.83
Total Due from Appellant	**$ 00**

120 PU-399-01-186 Pages: 2
Notice to Appellant of Actual Costs
by Public Service Commission
05/06/2002C: Comm Legal PUD (3) Mike AG's Office .

Dated this **6th** day of **May 2002.**

STATE OF NORTH DAKOTA

BY: _____

William W. Binek (ID #02990)
Special Assistant Attorney General
600 East Boulevard Avenue, Dept. 408
Bismarck, North Dakota 58505-0480
701/328-2400

Attorney for the Public Service Commission

STATE OF NORTH DAKOTA | **IN DISTRICT COURT**

COUNTY OF BURLEIGH | **SOUTH CENTRAL JUDICIAL DISTRICT**

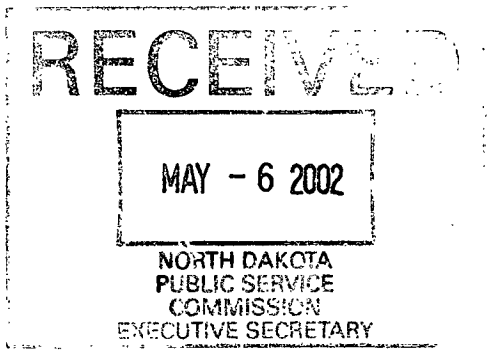
Montana-Dakota Utilities Co.,
Appellant,
v.

North Dakota Public Service Commission,

Appellee.

PSC Case No. PU-399-01-186

CIVIL NO. 08-02-C-01719
AFFIDAVIT OF SERVICE BY REGULAR MAIL



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

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **6th** day of **May 2002,** she deposited in the United States Mail, Bismarck, North Dakota, **1** envelope with first-class postage fully prepaid, securely sealed and each containing a photocopy of:

1. **Certificate of Record on Appeal**
2. **Notice to Appellant of Actual Costs**
3. **Affidavit of Mailing**

The envelope was addressed as follows:

Daniel S. Kuntz
Zuger Kirmis & Smith
P O Box 1695
Bismarck, ND 58502-1695

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L. Scott

Subscribed and sworn to before me this **6th** day of **May 2002.**

Susan K. Richter

Notary Public

SEAL

SUSAN K. RICHTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 15, 2004

Public Service Commission
State of North Dakota

RECEIVED
MAY - 3 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 3, 2002

Mr. Jon H. Mielke
Public Service Commission
600 E Boulevard Ave. Dept. 408
Bismarck, ND 58505-0480

RE: **Montana-Dakota Utilities Co.**
2000 Electric Operations
Annual Report
Case No. PU-399-01-186

Dear Jon:

Enclosed for filing in the above referenced case is the original and seven copies of the **Staff Response to Compliance Filing**.

Thank you.

Sincerely,

William W. Binek
Chief Counsel

WWBsls
Enclosure

C: Dan Kuntz

118 **PU-399-01-186** Pages: 1

Cover Letter re filing

by Public Service Commission by William W. Binek, Cl

05/03/2002C: Comm Legal PUD (3) Mike AG's Office

RECEIVED
MAY - 3 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

STAFF RESPONSE TO COMPLIANCE FILING

On May 2, 2002, Montana-Dakota Utilities Co. (MDU) filed tariff changes to comply with the Order of the Commission dated April 24, 2002 and the District Court's Order for Stay (Civil No. 08-02-C-01719) dated May 2, 2002. The Commission's Order required MDU to implement an across the board rate reduction sufficient to provide a total annual revenue reduction of $4.273 million effective for service rendered on and after May 8, 2002. The District Court's Order for Stay required a May 8, 2002 rate reduction sufficient to reduce annual revenue by $798,000. The Order further required MDU to file a suspending bond in the remaining amount of $3.475 million and establish an interest bearing escrow account at a bank or trust company authorized to do business in North Dakota.

MDU's compliance tariffs spread $798,000 over adjusted kWh sales volumes recorded for calendar year 2001. The adjustment reduces recorded volumes to reflect service contract discounts, thus increasing the net reduction per kWh. Mathematically stated: $798,000 / (1,299,222,818 – 6,135,155) kWh = $.00062 or 0.062 cents per kWh. For a typical residential customer without electric space heating and using approximately 750 kWh per month, the effect would be a billing reduction of about 47 cents per month or $5.58 per year.

Staff believes that MDU's compliance filing satisfies the Commission's Order as modified by the District Court's Order for Stay. Therefore, Staff recommends MDU's compliance tariff be approved.

Dated May 3, 2002.

William W. Binek
Chief Counsel

117 PU-399-01-186 Pages: 1
Staff Response to Compliance Filing
by Public Service Commission
05/03/2002C: Comm Legal PUD (3) Mike AG's Office .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY FIRST CLASS MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with first class postage, fully prepaid, securely sealed, containing a photocopy of:

STAFF RESPONSE TO COMPLIANCE FILING

The envelopes was addressed as follows:

Daniel S. Kuntz
Zuger Kirmis & Smith
P O Box 1695
Bismarck, ND 58502-1695

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L Scott

Subscribed and sworn to before me this **3rd** day of **May 2002.**

Susan K. Richter
Notary Public

SEAL

SUSAN K. RICHTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 15, 2004

116 **PU-399-01-186** Pages: 1

Affidavit of Service by First Class Mail

by Public Service Commission

05/03/2002C: Comm Legal PUD (3) Mike AG's Office

ZUGER KIRMIS & SMITH

COUNSELORS AND ATTORNEYS AT LAW

Lyle W. Kirmis
Lance D. Schreiner, P.C.
James S. Hill, P.C.*^
Patrick J. Ward**^
Rebecca S. Thiem, P.C.*
Daniel S. Kuntz, P.C.
Jerry W. Evenson, P.C.^
Lawrence A. Dopson
Tracy Vigness Kolb, P.C.
Shawnda R. Reid
Constance N. Hofland

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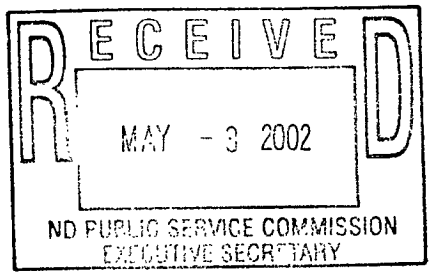
Of Counsel
John A. Zuger

Thomas O. Smith
1944-2001

Also licensed in
Minnesota *
Montana/Illinois **

^Certified Civil Trial Specialist
National Board of Trial Advocacy

May 2, 2002



William W. Binek
Special Assistant Attorney General
Public Service Commission
Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co. v. NDPSC
PSC Case No. PU-399-01-186
Civil No. 08-02-C-01719

Enclosure

115 **PU-399-01-186** Pages: 1

Estimated costs of preparing record for court received ($129.83)
by Montana-Dakota Utilities Co., a Division of MDU R

05/03/2002: Comm Legal PUD (3) Mike AG's Office

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

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

RECEIVED
MAY - 2 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

May 2, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-01-186
Compliance Tariffs

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of electric service tariff sheets revised to reflect the Commission's Order dated April 24, 2002 and the Order for Stay issued in District Court (Civil No. 08-02-C-01719) dated May 2, 2002.

As prescribed in the Order for Stay, the attached tariff sheets reflect an across-the board reduction in Montana-Dakota's North Dakota electric service rates sufficient to produce an annual revenue decrease of $798,000 to be effective with service rendered on and after May 8, 2002.

The workpapers underlying the proposed revised tariffs are also attached and denoted as Attachments A and B. As shown therein, the annual revenue decrease of $798,000 results in a reduction per Kwh of $.00062.

As also required by the Order for Stay, Montana-Dakota will file a suspending bond in the amount of $3.475 million and establish an interest bearing escrow account at a bank or trust company authorized to do business in North Dakota. Montana-Dakota shall, on a monthly basis, pay into the escrow account an amount equal to the energy sold for the prior month and the difference per Kwh between the $798,000 revenue reduction to be implemented on May 8, 2002 and the annual revenue reduction of $4,273,000 that would have been effectuated under the Commission's Order issued April 24, 2002. The difference per Kwh to be applied to monthly sales and deposited in the escrow account is $.00268.

As required by the Order of Stay Montana-Dakota will file a report on a monthly basis, beginning June 15, 2002, showing the amounts paid into the escrow account and the manner in which such amounts were determined.

114 PU-399-01-186 Pages: 53
Compliance Tariffs
by Montana-Dakota Utilities Co , a Division of MDU R
05/02/2002C: Comm Legal PUD (3) Mike AG's Office .

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

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Attachments
c: D. Schulz

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 3
Cancelling 3rd Revised Sheet No. 3

RESIDENTIAL ELECTRIC SERVICE Rate 10

AVAILABILITY:

In all communities served for single-phase residential electric service for domestic purposes only.

RATE:

Base Rate: $3.50

Energy Charge:

First	450 Kwh per month	7.022¢ per Kwh
Next	300 Kwh per month	6.622¢ per Kwh
Over	750 Kwh per month	6.022¢ per Kwh

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

1. Underground Service - Where provided, an additional charge of $1.50 per month for ninety-six monthly periods, totaling $144, will be added to the above rate.

2. Water Heating or Space Heating - Shall be provided where the customer has an approved installation for either water heating or space heating or both.

   a. Specifications for an approved water heating installation under this rate:

      1) The water heating installation shall not be used to supplement any other system of providing hot water service.

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
5th Revised Sheet No. 4
Cancelling 4th Revised Sheet No. 4

SPECIAL RESIDENTIAL ELECTRIC DUAL FUEL SPACE HEATING SERVICE Rate 11
(Formerly Designated Rate 53)

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. The customer's primary source of space heating shall be the electric portion of a dual fuel heating system. The customer shall be responsible for providing a secondary source of space heating. Customers taking dual fuel space heating service under this rate will also be eligible to receive controlled electric water heating service hereunder. Heat pump space heating equipment can only be served under this rate if a Company approved automatic transfer switch is installed to ensure energy used for non-heating (cooling) purposes is provided and metered under the applicable firm service rate and the heat pump is interrupted under the same criteria as defined for space heating equipment. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving space heating and water heating facilities with no provision for connecting other loads thereto. The customer's dual fuel system controls, circulating fans, pumps, heat pumps and any alternate fuel related equipment shall be served as firm load. Heat pump space heating equipment may be served under this rate only if it can be controlled by the Company and a Company approved automatic transfer switch is used to ensure non-heating (cooling) energy is served under the applicable firm service rate. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for customer's other electric service.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

RATE:

Base Rate:	$6.15 per month
Energy Charge:	3.265¢ per Kwh

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

Date Filed: May 2, 2002 **Effective Date:**

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 5
Cancelling 3rd Revised Sheet No. 5

SPECIAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13
(Formerly Designated Rate 55)

AVAILABILITY:

In all communities served for single-phase residential electric service customers who operate Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving only the space conditioning facilities with no provision for connecting other loads thereto. Unless otherwise specified by the Company, the point of delivery and the service voltage for this service shall be the same as for the customer's other electric service.

RATE:

Base Rate:	$5.50
Energy Rate:	2.972¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday. For all Kwh usage outside of the above designated hours, an energy charge of 11.133¢ per Kwh will apply.

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 7
Cancelling 3rd Revised Sheet No. 7

OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

AVAILABILITY:

In all communities served for single-phase residential electric service. The customer's wiring must be so arranged that all service can be measured through one meter.

RATE:

Base Rate: $5.50

On-Peak Energy: 13.034¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy: 2.755¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at the Off-Peak rate.

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

CONTRACT TERMS:

Customer agrees to contract for service under the Optional Time-of-Day Residential Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Residential Electric Service rate or of returning to the regular Residential Electric Service rate.

SPECIAL TERMS AND CONDITIONS:

1. Underground Service - Where provided, an additional charge of $1.50 per month for ninety-six monthly periods, totaling $144, will be added to the above rate.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 10
Cancelling 3rd Revised Sheet No. 10

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 outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be so arranged so 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:

Base Rate: $12.00

Demand Charge:

First	10 Kw or less of billing demand	No Charge
Over	10 Kw per month of billing demand	$5.25 per Kw

Energy Charge:

First	2,000 Kwh per month	7.646¢ per Kwh
Next	8,000 Kwh per month	5.746¢ per Kwh
Over	10,000 Kwh per month	5.246¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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. 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 special rules and regulations.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 0 2002
CASE NO. PU-399-01-186

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

SPECIAL GENERAL ELECTRIC DUAL FUEL SPACE HEATING SERVICE Rate 22
(Formerly Designated Rate 54)

AVAILABILITY:

In all communities served for small and large general electric service customers as defined in the availability section of Small General Electric Service Rate 20 and Large General Electric Service Rate 30 who operate Company approved interruptible electric space heating equipment so arranged to allow remote operation by the Company. The customer's primary source of space heating shall be the electric portion of a dual fuel heating system. The customer shall be responsible for providing a secondary source of space heating. Customers taking dual fuel space heating service under this rate will also be eligible to receive controlled electric water heating service hereunder. Heat pump space heating equipment can only be served under this rate if a Company approved automatic transfer switch is installed to ensure energy used for non-heating (cooling) purposes is provided and metered under the applicable firm service rate and the heat pump is interrupted under the same criteria as defined for space heating equipment. Domestic electric water heating may be served under the provisions of this Rate Schedule. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving space heating and water heating facilities with no provision for connecting other loads thereto. The customer's dual fuel system controls, circulating fans and pumps and all other alternate fuel related equipment shall be served as firm load. Heat pump space heating equipment may be served under this rate only if it can be controlled by the Company and a Company approved automatic transfer switch is used to ensure non-heating (cooling) energy is served under the applicable firm service rate. 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:

Base Rate:

Single Phase	$ 7.65
Three Phase	$12.70

Energy charge for Service at Primary Voltage: 3.112¢ per Kwh
Energy charge for Service at Secondary Voltage: 3.279¢ per Kwh

MINIMUM BILL:

Base rate.

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 12
Cancelling 3rd Revised Sheet No. 12

SPECIAL GENERAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 23
(Formerly Designated Rate 57)

AVAILABILITY:
In all communities served for general electric service customers who operate Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:
Service shall be provided through a separate meter serving only the space conditioning facilities with no provision for connecting other loads thereto. Unless otherwise specified by the Company, the point of delivery and the service voltage for this service shall be the same as for the customer's other electric service.

RATE:
Base Rate:

Single Phase	$ 7.80
Three Phase	$10.50

Energy Charge for Service at Primary Voltage:
3.146¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday.

For all Kwh usage outside of the above designated hours, an energy rate of 9.646¢ per Kwh will apply.

Energy Charge for Service at Secondary Voltage:
3.184¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday.

For all Kwh usage outside of the above designated hours, an energy rate of 10.122¢ per Kwh will apply.

MINIMUM BILL:
Base Rate.

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STATE OF NORTH DAKOTA
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NDPSC Volume 3
5th Revised Sheet No. 14
Cancelling 4th Revised Sheet No. 14

IRRIGATION POWER SERVICE Rate 25

AVAILABILITY:
For irrigation power where facilities therefor are located adjacent to the Company's three-phase lines for power and incidental lighting service provided the Company has sufficient available capacity.

RATE:
Demand Charge:
$2.00 per month per horsepower of connected load.

Energy Charge:
3.011¢ per Kwh.

MINIMUM SEASONAL CHARGE:
$19.03 per horsepower of connected load, based on the maximum horsepower connected during the season, but not less than $190.30. If the total seasonal bill through the month of August is less than $19.03 per horsepower of connected load, one-half of the deficiency will be billed in September and the balance in October.

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 109 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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

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STATE OF NORTH DAKOTA
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NDPSC Volume 3
4th Revised Sheet No. 15
Cancelling 3rd Revised Sheet No. 15

OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 Kilowatts or less except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

RATE:

Base Rate:

Single Phase	$13.50
Three Phase	$14.00

Demand Charge for Service at Primary Voltage:

On-Peak Demand Charge:

First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$5.00 per Kw

Off-Peak Demand Charge:

In excess of the greater of 10 Kw or of the on-peak demand	$1.90 per Kw

Demand Charge for Service at Secondary Voltage:

On-Peak Demand Charge:

First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$5.25 per Kw

Off-Peak Demand Charge:

In excess of the greater of 10 Kw or of the on-peak demand	$2.00 per Kw

Energy Charge for Service at Primary Voltage:

On-Peak Energy Charge:

9.391¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:

2.530¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

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OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

RATE: (Cont.)
Energy Charge for Service at Secondary Voltage:
On-Peak Energy Charge:
9.889¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:
2.666¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

MINIMUM BILL:
Base Rate plus Demand 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

DETERMINATION OF ON-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month. 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 special rules and regulations.

DETERMINATION OF OFF-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the off-peak period in the current month. 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 special rules and regulations.

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FEED GRINDING SERVICE Rate 27
(Closed)

AVAILABILITY:

For customers doing a custom feed grinding business for the operation of feed grinding equipment. No operation will be allowed between the hours of one-half hour before sunset and 10:00 o'clock p.m. under this schedule. No other load shall be included under this schedule.

The rate is restricted to feed grinding customers who were served under this rate prior to January 27, 1987. Any new feed grinding service will be served under the applicable general electric service rate.

RATE:

First	2,000 Kwh per month	7.922¢ per Kwh
Over	2,000 Kwh per month	5.922¢ per Kwh

MINIMUM BILL:

$1.70 per horsepower for first 5 horsepower of connected load; 35¢ per horsepower of connected load in excess of 5 horsepower; but not less than $17.25.

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 109 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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rate 130 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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MONTANA DAKOTA UTILITIES CO.
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STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 18
Cancelling 3rd Revised Sheet No. 18

LARGE GENERAL ELECTRIC SERVICE Rate 30

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so 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:

Base Rate: $15.00

Demand Charge: $5.25 per Kw of billing demand.

Energy Charge:

First	2,000 Kwh per month	6.275¢ per Kwh
Next	8,000 Kwh per month	4.975¢ per Kwh
Over	10,000 Kwh per month	4.375¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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 special rules and regulations.

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STATE OF NORTH DAKOTA
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NDPSC Volume 3
4th Revised Sheet No. 19
Cancelling 3rd Revised Sheet No. 19

OPTIONAL TIME-OF-DAY LARGE GENERAL ELECTRIC SERVICE Rate 31

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

RATE:

Base Rate: $17.00

Demand Charge for Service at Primary Voltage:

On-Peak Demand Charge:
$5.00 per Kw of billing demand

Off-Peak Demand Charge:
$1.90 per Kw in excess of the on-peak billing demand

Demand Charge for Service at Secondary Voltage:

On-Peak Demand Charge:
$5.25 per Kw of billing demand

Off-Peak Demand Charge:
$2.00 per Kw in excess of the on-peak billing demand

Energy Charge for Service at Primary Voltage:

On-Peak Energy Charge:
8.355¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:
2.836¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

Energy Charge for Service at Secondary Voltage:

On-Peak Energy Charge:
8.798¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

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OPTIONAL TIME-OF-DAY LARGE GENERAL ELECTRIC SERVICE Rate 31

RATE: (Cont.)
Off-Peak Energy Charge:
2.989¢ per Kwh for all Kwh's not covered by the On-Peak rating period.
All usage on Saturday and Sunday will be billed at Off-Peak rate.

MINIMUM BILL:
Base Rate plus Demand 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

DETERMINATION OF ON-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month. 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 special rules and regulations.

DETERMINATION OF OFF-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the off-peak period in the current month. 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 special rules and regulations.

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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

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STATE OF NORTH DAKOTA
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NDPSC
2nd Revised Volume 3
Sheet No. 22
Cancelling 1st Revised Sheet No. 22

FIRM SERVICE ECONOMIC DEVELOPMENT - RATE 34

AVAILABILITY:

In all communities served for all types of general electric service which meets one of the following qualifications:

A) New Customers - An applicant with total expected demand of 200 Kw per month and usage of 750,000 Kwh per year is eligible for service under this rate if it can meet any one of the following requirements: (i) its activities are largely or entirely different than that of the previous customer; (ii) that non-seasonal business has not been conducted at the premise for at least three billing periods prior to the application; (iii) that seasonal business has not been conducted at the premise for at least thirteen billing periods prior to the application; or (iv) the facility is newly constructed.

B) Existing Customers and Existing In-state Customers of Competing Suppliers - An existing customer, or an existing in-state customer of a competing supplier with increased demand of 200 Kw per month and increased usage of 750,000 Kwh per year is eligible for service under this rate. Only the expanded portion of the facility will be eligible for the negotiated rate. In addition, the new load must be supplied from a separately metered circuit with separate metering equipment to be installed at the customer's expense. Average usage at the original facility must be at least as great as that which occurred in the previous 12 month period.

RATE:

Base Rate: $15.00 per month

Demand Charge: $5.25 per Kw of billing demand

Energy Charge: Customer shall pay a negotiated rate not more than the ceiling or less than the floor as specified below.

Ceiling	Floor
4.5194.581¢ per Kwh	2.598¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand Charge.

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INTERRUPTIBLE LARGE POWER SERVICE Rate 39

AVAILABILITY:
In all communities served for power to customers having a demand of 200 Kw or more for its interruptible load. Electric energy for the interruptible load shall be supplied through a separately metered circuit at the same voltage and phase utilized to serve the balance of the customer's electrical load so arranged to allow remote operation by the Company.

TYPE OF SERVICE:
Service under this rate shall be taken by the customer at whatever primary voltage is available at the point of delivery but not less than 2,400 volts. In the event that it is necessary to build a substation on the Company's transmission line to serve the customer, the cost of building the substation shall be a matter of negotiation between the Company and the customer.

RATE:

Base Rate:	Specified in the electric service agreement with the Company.
Demand Charge:	$1.70 per Kw of billing demand
Energy Charge:	3.111¢ per Kwh

MINIMUM BILL:
Base Rate plus the Demand Charge (200 Kw minimum).

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 109 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 200 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 special rules and regulations.

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400 North Fourth Street
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STATE OF NORTH DAKOTA
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4th Revised Sheet No. 25
Cancelling 3rd Revised Sheet No. 25
Volume 3

SMALL MUNICIPAL ELECTRIC SERVICE Rate 40
(Closed)

AVAILABILITY:

For all lighting and power requirements with billing demands of 50 kilowatts or less for public buildings or locations supported by public tax levies, and for which the city is liable for payment, in all municipalities served where the Company is operating under a municipal franchise or permit, and the municipality has a standard contract for operation of a street lighting system and/or a municipal pumping system with the Company.

This rate is restricted to small municipal electric service customers who were served under this rate prior to January 27, 1987. Any new small municipal general electric service customer may take service under another applicable rate.

RATE:

Base Rate: $12.00

Demand Charge:

First	10 Kw or less of billing demand	No charge
Over	10 Kw per month of billing demand	$5.25 per Kw

Energy Charge:

First	2,000 Kwh per month	5.314¢ per Kwh
Next	8,000 Kwh per month	3.814¢ per Kwh
Over	10,000 Kwh per month	3.314¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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. 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 special rules and regulations.

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STATE OF NORTH DAKOTA ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 26
Cancelling 3rd Revised Sheet No. 26

STREET LIGHTING SERVICE Rate 41

AVAILABILITY:

For street lighting purposes including streets, alleys and other public grounds to either company-owned or municipally-owned street lighting systems. 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.

RATE:

6.862¢ per Kwh computed according to the total rated capacity of the lamps in use.

Special discount:

For contracts of less than three years	None
For contracts of three years or more	1% times the total number of years of the contract
Maximum discount	10%

MINIMUM BILL:

As provided in contract.

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 109 or any amendments or alterations thereto.

DISCOUNT FOR PRIMARY SERVICE:

A five percent discount shall be allowed if the customer provides his own transformers, related equipment, and distribution facilities down-stream of the meter, satisfactory to the Company, so that he can receive service and be metered at primary voltages of 2,400 volts or greater.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

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STATE OF NORTH DAKOTA
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NDPSC Volume 3
4th Revised Sheet No. 32
Cancelling 3rd Revised Sheet No. 32

MUNICIPAL PUMPING SERVICE Rate 48

AVAILABILITY:
Municipal pumping purposes only and provided the municipality uses electricity exclusively for all its pumping requirements and purchases all such electricity from the Company. The municipality must sign a contract for a minimum period of one year.

RATE:
Base Rate: $13.00

Demand Charge:
On connected loads of 10 Kw or less, a demand charge of $2.25 per Kw of connected load; on connected loads in excess of 10 Kw, demand charge of $2.25 per Kw of demand based upon the highest 15 minute interval demand as registered upon a demand meter during the month covered by the billing period but in no event less than $22.50.

Energy Charge: 4.368¢ per Kwh

Special discount:

For contracts of less than three years	None
For contracts of three years or more	1% times the total number of years of the contract
Maximum Discount	10%

MINIMUM BILL:
Base Rate plus Demand 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 109 or any amendments or alterations thereto.

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STATE OF NORTH DAKOTA
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NDPSC Volume 3
4th Revised Sheet No. 34
Cancelling 3rd Revised Sheet No. 34

GENERAL ELECTRIC WATER HEATING SERVICE Rate 50
(Closed)

AVAILABILITY:
In all communities served. The customer must also receive electric service from the Company under another rate.

This rate is restricted to general electric service customers who were served under this rate prior to July 1, 1977 or under Rate 51 prior to January 27, 1987. Any residential customer or new general service customer may take water heating service under another applicable rate.

RATE:
Base Rate: $2.00

Energy Charge: 5.118¢ per Kwh

MINIMUM BILL:
Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:
1. To qualify for service under this schedule, the installation must consist of a separate circuit of approved conduit or metal armored cable construction so that this service may be separately metered.

2. The foregoing schedule is subject to Rate 130 and any amend-ments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 36
Cancelling 3rd Revised Sheet No. 36

PRIVATE LIGHTING SERVICE Rate 52
(Formerly Designated Rates 24 and 28)

AVAILABILITY:
Company-owned flood light units and metallic vapor yard lights in all communities served.

RATE:
7.752¢ per Kwh computed according to the total rated capacity of the units in use.

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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

1. The Company will install, own and operate the flood light(s), and yard light(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dust to dawn.

2. 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 yard light(s) 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.

3. To the rate stated herein, bulb replacement and ownership costs for the units shall be added. The customer should consult with the Company for such costs.

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 40
Cancelling 3rd Revised Sheet No. 40

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 56
(Closed)

AVAILABILITY:

In all communities served for any general electric service customer for space heating, where the customer also takes service under another rate. Air-conditioning and water heating may also be taken in conjunction with space heating under this rate, but no other load will be allowed on this rate.

This rate is restricted to general electric service customers who were served under this rate prior to January 27, 1987. Any residential customer or new general electric service customer may take space heating service under another applicable rate.

RATE:

Base Rate: $2.00

Energy Charge: 5.850¢ per Kwh

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

1. Electric space heating and air-conditioning 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 primary source of space heating.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

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STATE OF NORTH DAKOTA
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4th Revised Sheet No. 3
Cancelling 3rd Revised Sheet No. 3

RESIDENTIAL ELECTRIC SERVICE Rate 10

AVAILABILITY:

In all communities served for single-phase residential electric service for domestic purposes only.

RATE:

Base Rate: $3.50

Energy Charge:

First	450 Kwh per month	7.022~~7.084~~¢ per Kwh
Next	300 Kwh per month	6.622~~6.684~~¢ per Kwh
Over	750 Kwh per month	6.022~~6.084~~¢ per Kwh

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

1. Underground Service - Where provided, an additional charge of $1.50 per month for ninety-six monthly periods, totaling $144, will be added to the above rate.

2. Water Heating or Space Heating - Shall be provided where the customer has an approved installation for either water heating or space heating or both.

   a. Specifications for an approved water heating installation under this rate:

      1) The water heating installation shall not be used to supplement any other system of providing hot water service.

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SPECIAL RESIDENTIAL ELECTRIC DUAL FUEL SPACE HEATING SERVICE Rate 11
(Formerly Designated Rate 53)

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. The customer's primary source of space heating shall be the electric portion of a dual fuel heating system. The customer shall be responsible for providing a secondary source of space heating. Customers taking dual fuel space heating service under this rate will also be eligible to receive controlled electric water heating service hereunder. Heat pump space heating equipment can only be served under this rate if a Company approved automatic transfer switch is installed to ensure energy used for non-heating (cooling) purposes is provided and metered under the applicable firm service rate and the heat pump is interrupted under the same criteria as defined for space heating equipment. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving space heating and water heating facilities with no provision for connecting other loads thereto. The customer's dual fuel system controls, circulating fans, pumps, heat pumps and any alternate fuel related equipment shall be served as firm load. Heat pump space heating equipment may be served under this rate only if it can be controlled by the Company and a Company approved automatic transfer switch is used to ensure non-heating (cooling) energy is served under the applicable firm service rate. Unless otherwise specified by the Company, the point of delivery and service voltage for this service shall be the same as for customer's other electric service.

RATE:

Base Rate:	$6.15 per month
Energy Charge:	3.265~~3.327~~¢ per Kwh

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

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STATE OF NORTH DAKOTA
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SPECIAL RESIDENTIAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 13
(Formerly Designated Rate 55)

AVAILABILITY:

In all communities served for single-phase residential electric service customers who operate Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving only the space conditioning facilities with no provision for connecting other loads thereto. Unless otherwise specified by the Company, the point of delivery and the service voltage for this service shall be the same as for the customer's other electric service.

RATE:

Base Rate: $5.50

Energy Rate: 2.972~~3.034~~¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday.

For all Kwh usage outside of the above designated hours, an energy charge of 11.133~~11.195~~¢ per Kwh will apply.

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

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4th Revised Sheet No. 7
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OPTIONAL TIME-OF-DAY RESIDENTIAL ELECTRIC SERVICE Rate 16

AVAILABILITY:

In all communities served for single-phase residential electric service. The customer's wiring must be so arranged that all service can be measured through one meter.

RATE:

Base Rate: $5.50

On-Peak Energy: 13.034~~13.096~~¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy: 2.755~~2.817~~¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at the Off-Peak rate.

MINIMUM BILL:

Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

CONTRACT TERMS:

Customer agrees to contract for service under the Optional Time-of-Day Residential Electric Service rate for a minimum period of one year. At the end of a one-year period, customer shall have the option of remaining under the Optional Time-of-Day Residential Electric Service rate or of returning to the regular Residential Electric Service rate.

SPECIAL TERMS AND CONDITIONS:

1. Underground Service - Where provided, an additional charge of $1.50 per month for ninety-six monthly periods, totaling $144, will be added to the above rate.

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NDPSC Volume 3
4th Revised Sheet No. 10
Cancelling 3rd Revised Sheet No. 10

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 outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be so arranged so 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:

Base Rate: $12.00

Demand Charge:

First	10 Kw or less of billing demand	No Charge
Over	10 Kw per month of billing demand	$5.25 per Kw

Energy Charge:

First	2,000 Kwh per month	7.646~~7.708~~¢ per Kwh
Next	8,000 Kwh per month	5.746~~5.808~~¢ per Kwh
Over	10,000 Kwh per month	5.246~~5.308~~¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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. 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 special rules and regulations.

SPECIAL GENERAL ELECTRIC DUAL FUEL SPACE HEATING SERVICE Rate 22
(Formerly Designated Rate 54)

AVAILABILITY:

In all communities served for small and large general electric service customers as defined in the availability section of Small General Electric Service Rate 20 and Large General Electric Service Rate 30 who operate Company approved interruptible electric space heating equipment so arranged to allow remote operation by the Company. The customer's primary source of space heating shall be the electric portion of a dual fuel heating system. The customer shall be responsible for providing a secondary source of space heating. Customers taking dual fuel space heating service under this rate will also be eligible to receive controlled electric water heating service hereunder. Heat pump space heating equipment can only be served under this rate if a Company approved automatic transfer switch is installed to ensure energy used for non-heating (cooling) purposes is provided and metered under the applicable firm service rate and the heat pump is interrupted under the same criteria as defined for space heating equipment. Domestic electric water heating may be served under the provisions of this Rate Schedule. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:

Service shall be provided through a separate meter serving space heating and water heating facilities with no provision for connecting other loads thereto. The customer's dual fuel system controls, circulating fans and pumps and all other alternate fuel related equipment shall be served as firm load. Heat pump space heating equipment may be served under this rate only if it can be controlled by the Company and a Company approved automatic transfer switch is used to ensure non-heating (cooling) energy is served under the applicable firm service rate. 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:

Base Rate:

Single Phase	$ 7.65
Three Phase	$12.70

Energy charge for Service at Primary Voltage: 3.112~~3.174~~¢ per Kwh
Energy charge for Service at Secondary Voltage: 3.279~~3.341~~¢ per Kwh

MINIMUM BILL:

Base rate.

SPECIAL GENERAL ELECTRIC THERMAL ENERGY STORAGE SERVICE Rate 23
(Formerly Designated Rate 57)

AVAILABILITY:
In all communities served for general electric service customers who operate Company approved thermal energy storage facilities for the purpose of utilizing off-peak electric energy for space conditioning. The customer must also receive electric service from the Company under another rate.

TYPE OF SERVICE:
Service shall be provided through a separate meter serving only the space conditioning facilities with no provision for connecting other loads thereto. Unless otherwise specified by the Company, the point of delivery and the service voltage for this service shall be the same as for the customer's other electric service.

RATE:
Base Rate:

Single Phase	$ 7.80
Three Phase	$10.50

Energy Charge for Service at Primary Voltage:
3.146~~3.208~~¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday.

For all Kwh usage outside of the above designated hours, an energy rate of 9.646~~9.708~~¢ per Kwh will apply.

Energy Charge for Service at Secondary Voltage:
3.184~~3.246~~¢ per Kwh for all Kwh's used during hours designated as 9 p.m. to 9 a.m. local time, Monday through Friday. This rate will also apply to all usage on Saturday and Sunday.

For all Kwh usage outside of the above designated hours, an energy rate of 10.122~~10.184~~¢ per Kwh will apply.

MINIMUM BILL:
Base Rate.

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STATE OF NORTH DAKOTA
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IRRIGATION POWER SERVICE Rate 25

AVAILABILITY:

For irrigation power where facilities therefor are located adjacent to the Company's three-phase lines for power and incidental lighting service provided the Company has sufficient available capacity.

RATE:

Demand Charge:

$2.00 per month per horsepower of connected load.

Energy Charge:

3.011~~3.073~~¢ per Kwh.

MINIMUM SEASONAL CHARGE:

$19.03~~$19.22~~ per horsepower of connected load, based on the maximum horsepower connected during the season, but not less than $190.30~~192.20~~. If the total seasonal bill through the month of August is less than $19.03~~19.22~~ per horsepower of connected load, one-half of the deficiency will be billed in September and the balance in October.

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 109 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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

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MONTANA-DAKOTA UTILITIES CO.
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STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

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4th Revised Sheet No. 15
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OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

AVAILABILITY:

In all communities served for all types of general electric service with billing demands of 50 Kilowatts or less except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

RATE:

Base Rate:

Single Phase	$13.50
Three Phase	$14.00

Demand Charge for Service at Primary Voltage:

On-Peak Demand Charge:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$5.00 per Kw
Off-Peak Demand Charge:	
In excess of the greater of 10 Kw or of the on-peak demand	$1.90 per Kw

Demand Charge for Service at Secondary Voltage:

On-Peak Demand Charge:	
First 10 Kw or less of billing demand	No Charge
Over 10 Kw per month of billing demand	$5.25 per Kw
Off-Peak Demand Charge:	
In excess of the greater of 10 Kw or of the on-peak demand	$2.00 per Kw

Energy Charge for Service at Primary Voltage:

On-Peak Energy Charge:

9.391~~9.453~~¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:

2.530~~2.592~~¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

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OPTIONAL TIME-OF-DAY SMALL GENERAL ELECTRIC SERVICE Rate 26

RATE: (Cont.)
Energy Charge for Service at Secondary Voltage:
On-Peak Energy Charge:
9.889~~9.951~~¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:
2.666~~2.728~~¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

MINIMUM BILL:
Base Rate plus Demand 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

DETERMINATION OF ON-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month. 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 special rules and regulations.

DETERMINATION OF OFF-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the off-peak period in the current month. 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 special rules and regulations.

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STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 16
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FEED GRINDING SERVICE Rate 27
(Closed)

AVAILABILITY:

For customers doing a custom feed grinding business for the operation of feed grinding equipment. No operation will be allowed between the hours of one-half hour before sunset and 10:00 o'clock p.m. under this schedule. No other load shall be included under this schedule.

The rate is restricted to feed grinding customers who were served under this rate prior to January 27, 1987. Any new feed grinding service will be served under the applicable general electric service rate.

RATE:

First	2,000 Kwh per month	7.922~~7.984~~¢ per Kwh
Over	2,000 Kwh per month	5.922~~5.984~~¢ per Kwh

MINIMUM BILL:

$1.70 per horsepower for first 5 horsepower of connected load; 35¢ per horsepower of connected load in excess of 5 horsepower; but not less than $17.25.

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 109 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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rate 130 and any amendments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

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STATE OF NORTH DAKOTA
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LARGE GENERAL ELECTRIC SERVICE Rate 30

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand except outside lighting, standby, resale or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so 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:

Base Rate: $15.00

Demand Charge: $5.25 per Kw of billing demand.

Energy Charge:

First	2,000 Kwh per month	6.275~~6.337~~¢ per Kwh
Next	8,000 Kwh per month	4.975~~5.037~~¢ per Kwh
Over	10,000 Kwh per month	4.375~~4.437~~¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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 special rules and regulations.

OPTIONAL TIME-OF-DAY LARGE GENERAL ELECTRIC SERVICE Rate 31

AVAILABILITY:

In all communities served for all types of general electric service exceeding 50 Kilowatts of billing demand except outside lighting, standby, resale, or other customers covered by special contracts or rate schedules applicable to specific services. The customer's wiring must be arranged so that all service can be measured through one meter.

RATE:

Base Rate: $17.00

Demand Charge for Service at Primary Voltage:

On-Peak Demand Charge:
$5.00 per Kw of billing demand

Off-Peak Demand Charge:
$1.90 per Kw in excess of the on-peak billing demand

Demand Charge for Service at Secondary Voltage:

On-Peak Demand Charge:
$5.25 per Kw of billing demand

Off-Peak Demand Charge:
$2.00 per Kw in excess of the on-peak billing demand

Energy Charge for Service at Primary Voltage:

On-Peak Energy Charge:
8.355~~8.417~~¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

Off-Peak Energy Charge:
2.836~~2.898~~¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

Energy Charge for Service at Secondary Voltage:

On-Peak Energy Charge:
8.798~~8.860~~¢ per Kwh for all Kwh's used during peak hours designated as 9 a.m. to 9 p.m. local time, Monday through Friday.

OPTIONAL TIME-OF-DAY LARGE GENERAL ELECTRIC SERVICE Rate 31

RATE: (Cont.)
Off-Peak Energy Charge:
2.989~~3.051~~¢ per Kwh for all Kwh's not covered by the On-Peak rating period. All usage on Saturday and Sunday will be billed at Off-Peak rate.

MINIMUM BILL:
Base Rate plus Demand 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

DETERMINATION OF ON-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the on-peak period in the current month. 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 special rules and regulations.

DETERMINATION OF OFF-PEAK BILLING DEMAND:
The demand in kilowatts for billing purposes shall be the maximum 15 minute measured demand for the off-peak period in the current month. 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 special rules and regulations.

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 90% lagging and 90% leading. If the customer operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $1.75 per Kvar of such excess demand.

FIRM SERVICE ECONOMIC DEVELOPMENT - RATE 34

AVAILABILITY:

In all communities served for all types of general electric service which meets one of the following qualifications:

A) New Customers - An applicant with total expected demand of 200 Kw per month and usage of 750,000 Kwh per year is eligible for service under this rate if it can meet any one of the following requirements: (i) its activities are largely or entirely different than that of the previous customer; (ii) that non-seasonal business has not been conducted at the premise for at least three billing periods prior to the application; (iii) that seasonal business has not been conducted at the premise for at least thirteen billing periods prior to the application; or (iv) the facility is newly constructed.

B) Existing Customers and Existing In-state Customers of Competing Suppliers - An existing customer, or an existing in-state customer of a competing supplier with increased demand of 200 Kw per month and increased usage of 750,000 Kwh per year is eligible for service under this rate. Only the expanded portion of the facility will be eligible for the negotiated rate. In addition, the new load must be supplied from a separately metered circuit with separate metering equipment to be installed at the customer's expense. Average usage at the original facility must be at least as great as that which occurred in the previous 12 month period.

RATE:

Base Rate: $15.00 per month

Demand Charge: $5.25 per Kw of billing demand

Energy Charge: Customer shall pay a negotiated rate not more than the ceiling or less than the floor as specified below.

Ceiling	Floor
4.5194.581¢ per Kwh	2.598¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand Charge.

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INTERRUPTIBLE LARGE POWER SERVICE Rate 39

AVAILABILITY:
In all communities served for power to customers having a demand of 200 Kw or more for its interruptible load. Electric energy for the interruptible load shall be supplied through a separately metered circuit at the same voltage and phase utilized to serve the balance of the customer's electrical load so arranged to allow remote operation by the Company.

TYPE OF SERVICE:
Service under this rate shall be taken by the customer at whatever primary voltage is available at the point of delivery but not less than 2,400 volts. In the event that it is necessary to build a substation on the Company's transmission line to serve the customer, the cost of building the substation shall be a matter of negotiation between the Company and the customer.

RATE:

Base Rate:	Specified in the electric service agreement with the Company.
Demand Charge:	$1.70 per Kw of billing demand
Energy Charge:	3.111~~3.173~~¢ per Kwh

MINIMUM BILL:
Base Rate plus the Demand Charge (200 Kw minimum).

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 109 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 200 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 special rules and regulations.

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SMALL MUNICIPAL ELECTRIC SERVICE Rate 40
(Closed)

AVAILABILITY:

For all lighting and power requirements with billing demands of 50 kilowatts or less for public buildings or locations supported by public tax levies, and for which the city is liable for payment, in all municipalities served where the Company is operating under a municipal franchise or permit, and the municipality has a standard contract for operation of a street lighting system and/or a municipal pumping system with the Company.

This rate is restricted to small municipal electric service customers who were served under this rate prior to January 27, 1987. Any new small municipal general electric service customer may take service under another applicable rate.

RATE:

Base Rate: $12.00

Demand Charge:

First	10 Kw or less of billing demand	No charge
Over	10 Kw per month of billing demand	$5.25 per Kw

Energy Charge:

First	2,000 Kwh per month	5.314~~5.376~~¢ per Kwh
Next	8,000 Kwh per month	3.814~~3.876~~¢ per Kwh
Over	10,000 Kwh per month	3.314~~3.376~~¢ per Kwh

MINIMUM BILL:

Base Rate plus Demand 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 109 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. 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 special rules and regulations.

STREET LIGHTING SERVICE Rate 41

AVAILABILITY:

For street lighting purposes including streets, alleys and other public grounds to either company-owned or municipally-owned street lighting systems. 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.

RATE:

6.862~~6.924~~¢ per Kwh computed according to the total rated capacity of the lamps in use.

Special discount:

For contracts of less than three years	None
For contracts of three years or more	1% times the total number of years of the contract
Maximum discount	10%

MINIMUM BILL:

As provided in contract.

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 109 or any amendments or alterations thereto.

DISCOUNT FOR PRIMARY SERVICE:

A five percent discount shall be allowed if the customer provides his own transformers, related equipment, and distribution facilities down-stream of the meter, satisfactory to the Company, so that he can receive service and be metered at primary voltages of 2,400 volts or greater.

FUEL CLAUSE:

Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

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

MUNICIPAL PUMPING SERVICE Rate 48

AVAILABILITY:

Municipal pumping purposes only and provided the municipality uses electricity exclusively for all its pumping requirements and purchases all such electricity from the Company. The municipality must sign a contract for a minimum period of one year.

RATE:

Base Rate: $13.00

Demand Charge:

On connected loads of 10 Kw or less, a demand charge of $2.25 per Kw of connected load; on connected loads in excess of 10 Kw, demand charge of $2.25 per Kw of demand based upon the highest 15 minute interval demand as registered upon a demand meter during the month covered by the billing period but in no event less than $22.50.

Energy Charge: 4.368~~4.430~~¢ per Kwh

Special discount:

For contracts of less than three years	None
For contracts of three years or more	1% times the total number of years of the contract
Maximum Discount	10%

MINIMUM BILL:

Base Rate plus Demand 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 109 or any amendments or alterations thereto.

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 34
Cancelling 3rd Revised Sheet No. 34

GENERAL ELECTRIC WATER HEATING SERVICE Rate 50
(Closed)

AVAILABILITY:
In all communities served. The customer must also receive electric service from the Company under another rate.

This rate is restricted to general electric service customers who were served under this rate prior to July 1, 1977 or under Rate 51 prior to January 27, 1987. Any residential customer or new general service customer may take water heating service under another applicable rate.

RATE:
Base Rate: $2.00

Energy Charge: 5.118~~5.180~~¢ per Kwh

MINIMUM BILL:
Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:
1. To qualify for service under this schedule, the installation must consist of a separate circuit of approved conduit or metal armored cable construction so that this service may be separately metered.

2. The foregoing schedule is subject to Rate 130 and any amend-ments or alterations thereto or additional rules and regulations promulgated by the Company under the laws of the state.

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

PRIVATE LIGHTING SERVICE Rate 52
(Formerly Designated Rates 24 and 28)

AVAILABILITY:
Company-owned flood light units and metallic vapor yard lights in all communities served.

RATE:
7.752~~7.814~~¢ per Kwh computed according to the total rated capacity of the units in use.

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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:

1. The Company will install, own and operate the flood light(s), and yard light(s) including a suitable reflector, bracket for mounting and automatic device to control operating hours set to operate from dust to dawn.

2. 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 yard light(s) 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.

3. To the rate stated herein, bulb replacement and ownership costs for the units shall be added. The customer should consult with the Company for such costs.

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

STATE OF NORTH DAKOTA
ELECTRIC RATE SCHEDULE

NDPSC Volume 3
4th Revised Sheet No. 40
Cancelling 3rd Revised Sheet No. 40

GENERAL ELECTRIC SPACE HEATING SERVICE Rate 56
(Closed)

AVAILABILITY:
In all communities served for any general electric service customer for space heating, where the customer also takes service under another rate. Air-conditioning and water heating may also be taken in conjunction with space heating under this rate, but no other load will be allowed on this rate.

This rate is restricted to general electric service customers who were served under this rate prior to January 27, 1987. Any residential customer or new general electric service customer may take space heating service under another applicable rate.

RATE:
Base Rate: $2.00

Energy Charge: 5.850~~5.912~~¢ per Kwh

MINIMUM BILL:
Base 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 109 or any amendments or alterations thereto.

FUEL CLAUSE:
Bills are subject to an adjustment for cost of fuel as provided in Rate 58, or any amendments or alterations thereto.

SPECIAL TERMS AND CONDITIONS:
1. Electric space heating and air-conditioning 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 primary source of space heating.

Date Filed: May 2, 2002 Effective Date:

Issued By: Donald R. Ball
Director of Regulatory Affairs

Case No.: PU-399-01-186

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Rates Adjusted to Reflect Revenue Decrease of $798,000
To Be Effective May 8, 2002

Rate		Rates Effective 1/1/89 Case No. 10,799			Rates Effective 5/8/02 Case No. PU-399-01-186 1/		
		Base Rate	Energy	Demand	Base Rate	Energy	Demand
Residential	10	$3.50			$3.50		
First 450 Kwh			$0.07084			$0.07022	
Next 300 Kwh			$0.06684			$0.06622	
Over 750 Kwh			$0.06084			$0.06022	
Resid. Dual Fuel	11	$6.15	$0.03327		$6.15	$0.03265	
Residential Thermal Storage	13	$5.50			$5.50		
Off-Peak			$0.03034			$0.02972	
On-Peak			$0.11195			$0.11133	
Optional Res.TOD	16	$5.50			$5.50		
Off-Peak			$0.13096			$0.13034	
On-Peak			$0.02817			$0.02755	
Small General Service	20	$12.00			$12.00		
Over 10 Kw				$5.25			$5.25
First 2,000 Kwh			$0.07708			$0.07646	
Next 8,000 Kwh			$0.05808			$0.05746	
Over 10,000 Kwh			$0.05308			$0.05246	
General Dual Fuel	22						
Single Phase		$7.65			$7.65		
Three Phase		$12.70			$12.70		
Primary Voltage			$0.03174			$0.03112	
Secondary Voltage			$0.03341			$0.03279	
Gen Serv. Thermal Storage	23						
Single Phase		$7.80			$7.80		
Three Phase		$10.50			$10.50		
Primary Voltage							
Off-Peak			$0.03208			$0.03146	
On-Peak			$0.09708			$0.09646	
Secondary Voltage							
Off-Peak			$0.03246			$0.03184	
On-Peak			$0.10184			$0.10122	
Irrigation	25		$0.03073	$2.00		$0.03011	$2.00
Minimum Seasonal 2/		$19.22			$19.03		

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION

MAY 8 2002

CASE NO. PU-399-01-186

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Rates Adjusted to Reflect Revenue Decrease of $798,000
To Be Effective May 8, 2002

Rate		Rates Effective 1/1/89 Case No. 10,799 Base Rate	Energy	Demand	Rates Effective 5/8/02 Case No. PU-399-01-186 1/ Base Rate	Energy	Demand
TOD Small General	26						
Single Phase		$13.50			$13.50		
Three Phase		$14.00			$14.00		
Primary Voltage:							
On-Peak (Over 10 Kw)				$5.00			$5.00
Off-Peak (Over 10 Kw)				$1.90			$1.90
Secondary Voltage:							
On-Peak (Over 10 Kw)				$5.25			$5.25
Off-Peak (Over 10 Kw)				$2.00			$2.00
Energy Charge:							
Primary Voltage:							
On-Peak			$0.09453			$0.09391	
Off-Peak			$0.02592			$0.02530	
Secondary Voltage:							
On-Peak			$0.09951			$0.09889	
Off-Peak			$0.02728			$0.02666	
Feed Grinding	27						
First 2,000 Kwh			$0.07984			$0.07922	
Over 2,000 Kwh			$0.05984			$0.05922	
Minimum Bill		3/					3/
Large General	30	$15.00			$15.00		
All Kw				$5.25			$5.25
First 2,000 Kwh			$0.06337			$0.06275	
Next 8,000 Kwh			$0.05037			$0.04975	
Over 10,000 Kwh			$0.04437			$0.04375	
Large General Contract	30[c]	$15.00			$15.00		
All Kw				$5.25			$5.25
First 1,000,000 Kwh			$0.04437			$0.04375 4/	
Over 1,000,000 Kwh			$0.02598			$0.02562 4/	
TOD Large General	31	$17.00			$17.00		
Primary Voltage:							
On-Peak				$5.00			$5.00
Off-Peak				$1.90			$1.90
Secondary Voltage:							
On-Peak				$5.25			$5.25
Off-Peak				$2.00			$2.00
Energy Charge:							
Primary Voltage:							
On-Peak			~~$0.08417~~			$0.08355	
Off-Peak			$0.02898			$0.02836	
Secondary Voltage:							
On-Peak			$0.08860			$0.08798	
Off-Peak			$0.03051			$0.02989	

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Rates Adjusted to Reflect Revenue Decrease of $798,000
To Be Effective May 8, 2002

Rate		Rates Effective 1/1/89 Case No. 10,799 Base Rate	Energy	Demand	Rates Effective 5/8/02 Case No. PU-399-01-186 1/ Base Rate	Energy	Demand
Economic Development	34	$15.00		$5.25	$15.00		$5.25
Ceiling Rate			$0.04581			$0.04519	
Floor Rate			$0.02598			$0.02598 5/	
Interruptible Large	39	6/	$0.03173	$1.70		$0.03111	$1.70
Small Municipal	40	$12.00			$12.00		
Over 10 Kw				$5.25			$5.25
First 2,000 Kwh			$0.05376			$0.05314	
Next 8,000 Kwh			$0.03876			$0.03814	
Over 10,000 Kwh			$0.03376			$0.03314	
Lighting	41						
Company Owned			$0.06924			$0.06862	
Municipal Discount			$0.06580			$0.06518	
Municipal Pumping	48	$13.00	$0.04430	$2.25	$13.00	$0.04368	$2.25
Minimum Demand				$22.50			$22.50
General Water Heating	50	$2.00	$0.05180		$2.00	$0.05118	
Private Lighting	52		$0.07814			$0.07752	
Space Heating	56	$2.00	$0.05912		$2.00	$0.05850	

1/ Decrease of $.00062 per Kwh. See Attachment B.
2/ Minimum Seasonal Charge (5 Months x Demand Charge) + (300 Kwh x Rate 25 Energy Charge)
3/ $1.70 per HP for 1st 5 HP; $.35 per HP of connected load in excess of 5 HP but not less than $17.25
4/ Per contract- energy charge changes tied to change in Rate 30 energy charges.
Average Rate applicable to 1st 1,000,000 Kwh under Rate 30 $0.04446
1st Block % change based on decrease of $.00062. -1.395%
2nd Block % change ($.00062/$.04437) -1.397%
5/ Floor rate not adjusted.
6/ Base rate is determined individually and set forth in contract.

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-186

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Revenue Allocation - 12 Months Ended December 31, 2001

Rate	Rate Class	Actual - 12/31/01 Kwh	Total Revenue	Discounted Kwh 1/		% Discount	Kwh Adjustment	Net Kwh
Residential								
10	Residential	476,899,190	$33,004,330					476,899,190
11	Dual Fuel	11,072,961	376,468					11,072,961
13	Thermal Storage	99,129	3,211					99,129
16	T-O-D	240,587	13,494					240,587
50	General Water Heating	2,933	189					2,933
56	General Space Heating	95,084	5,460					95,084
	Total Residential	488,409,884	33,403,152	0			0	488,409,884
Small General Service								
20	Small General Service	208,548,443	16,426,475	198,997		10%	(19,900)	208,528,543
22	Dual Fuel	3,441,240	116,904	-				3,441,240
26	T-O-D	1,278,070	63,625	-				1,278,070
27	Feed Grinding	33,416	4,467	-				33,416
40	Municipal Service	4,497,543	303,592	-				4,497,543
50	General Water Heating	230,139	12,865	-				230,139
56	General Space Heating	11,222,995	628,659	216,800		10%	(21,680)	11,201,315
29/95	Special & Cogeneration	807	75	-				807
	Total Small General Service	229,252,653	17,556,662	415,797			(41,580)	229,211,073
Large General Service								
30	Large General Service	489,646,992	27,225,443	29,641,320		10%	(2,964,132)	486,682,860
30	Contract Rate 30 [a]	30,000,000	1,163,837	-	2/			30,000,000
30	Fixed Contract Rate 30	3,129,280	140,407	3,129,280	3/		(3,129,280)	0
31	T-O-D	249,807	23,647	-				249,807
32	Large Power Service	-	-	-				0
39	Interruptible Large Power	7,258,812	248,568	-				7,258,812
	Total Large General Service	530,284,891	28,801,902	32,770,600			(6,093,412)	524,191,479

CASE NO. PU-359-01-180
MAY 2002
BEFORE THE PUBLIC SERVICE COMMISSION OF NORTH DAKOTA

Attachment B
Page 1 of 2

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Revenue Allocation - 12 Months Ended December 31, 2001

Rate	Rate Class	Actual - 12/31/01 Kwh	Total Revenue	Discounted Kwh 1/	% Discount	Kwh Adjustment	Net Kwh
Irrigation							
25	Irrigation Service	739,892	35,000	-	-		739,892
Municipal Pumping							
48	Municipal Pumping	26,110,532	1,213,484	-	-		26,110,532
Lighting							
41	Street Lighting -Company	10,230,362	602,060	-	-		10,230,362
42	Street Lighting -Municipal	10,478,226	576,855	-	-		10,478,226
52	Private Lighting	3,716,378	282,863	1,632	10%	(163)	3,716,215
	Total Lighting	24,424,966	1,461,778	1,632		(163)	24,424,803
Total North Dakota		1,299,222,818	$82,471,978	33,188,029		(6,135,155)	1,293,087,663
Total Revenue Decrease		($798,000)					
Decrease per Kwh		($0.00062)					

1/ Discounted per contract.
2/ Contract rates based on % change in Rate 30. Rate components adjusted separately.
3/ Fixed contract.

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
MAY 8 2002
CASE NO. PU-399-01-184

Attachment B
Page 2 of 2

APPROVED
DATE: 5-1-02
KMF

MOTION

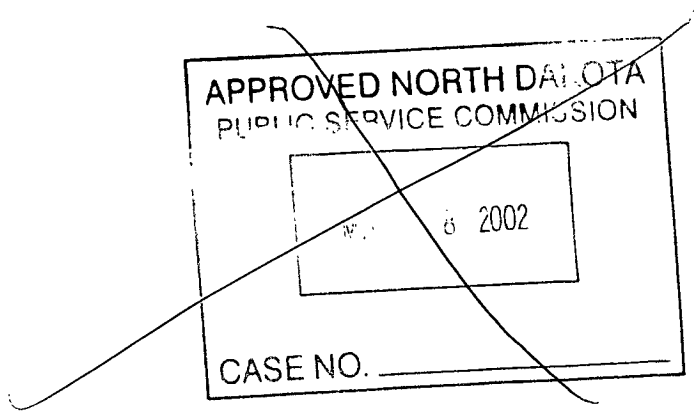
May 1, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission acknowledge its request to the Attorney General's office to provide legal assistance in Montana-Dakota Utilities Co.'s 2000 Electric Operation Annual Report appeal case, and that Doug Bahr, Solicitor General, has been assigned to assist the Commission in this proceeding.

IJS/sdh



113 PU-399-01-186 Pages: 1

Motion

by Public Service Commission

05/01/2002C: Comm Legal PUD (3) Mike AG's Office

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Douglas W Schulz
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 4-29-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 2510 0005 8654 8839

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 4-29-02

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 2510 0005 8654 8853

PS Form 3811, August 2001 Domestic Return Receipt 102595-01-M-2509

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Douglas W Schulz
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 1-17-03

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7001 2510 0001 2975 2815

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1035

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
William P Pearce
PO Box 400
Bismarck ND 58502-0400

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) Roger Kramer C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) [signature] C. Date of Delivery 1-17-03

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise

Bill - $40.56/hr (Salary + Benef.
Sandi - .32¢/min -

Comp. time

Bill ½ hr	$20.28
Sandi 2 hrs.	38.40
	$58.68

Copy -

655 pg - x 5¢ = $32.75

Search time	38.40
2 hrs -	71.15
* 120 min x 32¢ per min	

PL-399-01-186 $129.83
4-3002

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

April 30, 2002

Ms. Debra Simenson, Clerk
Burleigh County District Court
P. O. Box 1055
Bismarck, ND 58502-1055

Re: Civil No. 08-02-C-01719
Montana-Dakota Utilities Co., Appellant, vs
North Dakota Public Service Commission, Appellee.
PSC Case No. PU-399-01-186

Dear Ms. Simenson:

Enclosed for filing in Civil No. 08-02-C-01719 please find the originals of the **Notice to Appellant of Estimated Costs and Affidavit of Mailing.**

If you have any questions, please call. Thank you.

Sincerely,

William W. Binek
Special Assistant Attorney General

WWBsls
Enclosure

c: Daniel S. Kuntz
Doug Bahr

112 **PU-399-01-186** Pages: 1

Letter to Clerk of Court re filig of Notice of Estimated Costs
by Public Service Commission

04/30/2002C: Comm Legal PUD (3) Mike AG's Office

STATE OF NORTH DAKOTA

IN DISTRICT COURT

COUNTY OF BURLEIGH

SOUTH CENTRAL JUDICIAL DISTRICT

Montana-Dakota Utilities Co., Appellant,	
v.	**CIVIL NO. 08-02-C-01719 NOTICE TO APPELLANT OF ESTIMATED COSTS**
North Dakota Public Service Commission,	
Appellee.	
PSC Case No. PU-399-01-183	

TO: **Daniel S. Kuntz, Zuger Kirmis & Smith**, P. O. Box 1695, Bismarck, ND 58502-1695, **Attorney for Appellant Montana-Dakota Utilities Co.**

Under N.D.C.C. § 28-32-17 (2) when a Public Service Commission decision is appealed, the Public Service Commission must notify the appellant of the estimated costs of preparing and filing the record. The appellant must then pay the Public Service Commission the amount estimated. If the actual costs are more than the estimated costs, the appellant must pay the difference. If the actual costs are less than the estimated costs, the Public Service Commission will refund the difference.

PLEASE TAKE NOTICE that the total estimated costs for preparing and filing the record in the captioned matter are as set forth below. The costs are based on certifying the documents identified with an " * " on the docket card listing attached. If

you believe that any other documents should be certified to the Court as part of the record please let the undersigned know within 10 days of the date of this notice.

Copies	$71.15
Compilation Time	$58.68
Total Estimated Costs	**$129.83**

Dated this **30th** day of **April 2002.**

STATE OF NORTH DAKOTA

BY: _____

William W. Binek (~~ID~~ #02990)
Special Assistant Attorney General
600 East Boulevard Avenue, Dept. 408
Bismarck, North Dakota 58505-0480
701/328-2400

Attorney for the Public Service Commission

Public Service Commission

4/30/2002

Case File / Docket Card Report

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report — Catagory Reports
Filed 04/17/2001 Open — Closed 04/16/2001

	Doc#	Filed		Pages
*	1	4/16/2001	**Report** By Montana-Dakota Utilities Co., a Division of MDU R	12
*	2	5/4/2001	**Memo to Commission re Annual Report** By Public Service Commission	2
*	3	5/4/2001	**Letter to MDU re annual report** By Mike Diller Public Service Commission	1
	4	5/4/2001	**Affidavit of Service by Ordinary Mail** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\4.doc	1
	5	5/17/2001	**Contract #PU-425-01 issued to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\5.doc	4
	6	5/17/2001	**Mtn approved to execute an $8000 contract w/Snavely King Majoros O'Connor & L** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\6.doc	1
*	7	5/17/2001	**Motion appointing Diller & Binek as advocacy staff** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\7.doc	1
	8	5/17/2001	**Cover letter re contract for consulting services** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\8.doc	1
*	9	5/23/2001	**Signed Contract No. PU-425-01** By Snavely King Majoros O'Connor & Lee, Inc.	6
	10	7/11/2001	**Contract No. PU-427-01 issued to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission	4
*	11	7/11/2001	**Motion to execute contract to Snavely King Majoros O'Connor & Lee Inc** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\11.doc	1
	12	7/11/2001	**Letter to consultant re Contract** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\12.doc	1
*	13	7/20/2001	**Signed Contract No. PU-427-01** By Snavely King Majoros O'Connor & Lee, Inc.	5
*	14	9/7/2001	**Direct Testimony of Charles W King** Exhibit : 4 By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\14.doc	96
*	15	9/7/2001	**Direct Testimony of Mike Diller** Exhibit : 1 By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\15.doc	40
*	16	9/7/2001	**Complaint** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\16.doc	3
*	17	9/7/2001	**Cover letter re Complaint** By Mike Diller, Director of Accounting Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\17.doc	1
*	18	9/19/2001	**Motion appointing Lein as advocacy staff / Illona & Fahn as Commission advisors** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\18.doc	1
*	19	9/19/2001	**Motion - Complaint states a prima facie case & serve complaint on MDU** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\19.doc	1

* denotes certified to courts

PU 399 01 186 Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc
2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
*	20	9/21/2001	**Affidavit of Service to serve Complaint on MDU**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\20.doc	
*	21	10/9/2001	**Answer**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	4
*	22	10/18/2001	**Errata to Staff's Testimony**	
			By Mike Diller Public Service Commission	4
	23	10/18/2001	**Affidavit of Service**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\23.doc	
*	24	11/5/2001	**Letter re off-system sales**	
			By Comm. Wefald Public Service Commission	6
*	25	11/14/2001	**Letter confirming procedural schedule**	
			By William P. Pearce, Attorney Montana-Dakota Utilities Co., a Division of MDU Re	2
*	26	11/21/2001	**Response To Comm. Wefald's letter**	
			By Mike Diller Public Service Commission	4
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\26.doc	
	27	11/21/2001	**Affidavit of Service**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\27.doc	
*	28	11/21/2001	**Notice of Hearing, Notice of Public Input Sesions & Notice of Intervention**	
			By Public Service Commission	2
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\28.doc	
*	29	11/21/2001	**Motion**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\OrderLib\2001\010186\29.doc	
	30	11/23/2001	**Notice e-mailed to NDNA requesting publication**	
			By Public Service Commission	2
	31	11/23/2001	**Affidavits of Service**	
			By Public Service Commission	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\31.doc	
*	32	11/27/2001	**Request for ALJ for Feb. 25th Hearing**	
			By Public Service Commission	2
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\32.doc	
*	33	11/29/2001	**Allen Hoberg appointed ALJ**	
			By Office of Administrative Hearings	1
	34	12/3/2001	**Videoconference Confirmation**	
			By North Dakota Interactive Video Network	1
*	35	12/4/2001	**Response to Commissioner Wefald's Nov. 5th letter**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2
	36	12/13/2001	**Affidavit of Publication**	
			By Golden Valley News	1
	37	12/9/2001	**Display ad for Public Input Session**	
			By Bismarck Tribune	1
	38	12/20/2001	**Affidavit of Publication**	
			By North Dakota Advertising Service, Inc.	1

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2000 Electric Operations
Annual Report Catagory Reports
Filed 04/17/2001 Open Closed 04/16/2001

	Doc#	Filed		Pages
	39	1/3/2001	**Letter to MDU re request for court reporter**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\39.doc	
*	40	1/4/2002	**Affidavit of Publication & clippings**	
			By Williston Daily Herald	5
	41	1/8/2002	**Publication billing for display ad**	
			By Dickinson Press & The Advertizer	3
	42	1/9/2002	**Request for a court reporter to be present at hearing**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	43	1/9/2002	**Court reporter ordered for 2/25/02 hearing**	
			By Public Service Commission	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\43.doc	
	44	1/9/2002	**Affidavit of Publication**	
			By Bismarck Tribune	3
*	45	1/11/2002	**Direct Testimony of Rita A Mulkern**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	46	1/11/2002	**Direct Testimony of Donald R Ball**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	8
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	47	1/11/2002	**Direct Testimony of Gerald L Gress**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	6
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	48	1/11/2001	**Direct Testimony of Terry L Blinsky**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	11
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	49	1/11/2002	**Direct Testimony of J Stephen Gaske**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	65
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	50	1/11/2002	**Direct Testimony of C Wayne Fox**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	9
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
*	51	1/11/2002	**Cover letter re direct testimony**	
		Exhibit : 6	By Montana-Dakota Utilities Co., a Division of MDU Re	1
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\45.doc	
	52	1/24/2002	**Affidavit of Publication**	
			By Adams County Record	1
*	53	2/11/2002	**Rebuttal Testimony of Charles W King**	
		Exhibit : 5	By Snavely King Majoros O'Connor & Lee, Inc.	19
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\53.doc	
*	54	2/11/2002	**Rebuttal Testimony of Mike Diller**	
		Exhibit : 2	By Mike Diller Public Service Commission	23
\\Regulator\Case Mgmt\OrderLib\2001\010186\			\\Regulator\Case Mgmt\Orderlib\2001\010186\54.doc	
*	55	2/11/2002	**Cover letter re Staff's Rebuttal Testimony**	
			By Mike Diller Public Service Commission	1
*	56	2/19/2002	**Surrebuttal Testimony of Rita A Mulkern**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	5
*	57	2/19/2002	**Surrebuttal Testimony of Donald R Ball**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	9

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*	58	2/19/2002	**Surrebuttal Testimony of Richard A Espeland**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	7
*	59	2/19/2002	**Surrebuttal Testimony of Terry L Blinsky**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	10
*	60	2/19/2002	**Surrebuttal Testimony of Paul L. Wilkinson**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	11
*	61	2/19/2002	**Surrebuttal Testimony of Roger Joseph Schiffman**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	28
*	62	2/19/2002	**Surrebuttal Testimony of Douglass A. Mahowald**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	7
*	63	2/19/2002	**Surrebuttal Testimony of J. Stephen Gaske**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	30
*	64	2/19/2002	**Cover Letter re Surrebuttal Testimony**	
		Exhibit : 7	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	65	3/1/2002	**Exhibit List from Feb, 25 & 26, 2002 Hearing**	
			By Office of Administrative Hearings	2
*	66	3/1/2002	**Letter closing ALJ's file**	
			By Office of Administrative Hearings	1
*	67	3/5/2002	**Details of the change in Account 920/salary changes**	
		xhibit : Late Filed 20	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	68	3/5/2002	**Details of fixed costs of aircraft**	
		xhibit : Late Filed 19	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	69	3/5/2002	**Details on Update Exhibit No. (DRB-2) to include insurance premium expense**	
		xhibit : Late Filed 18	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	70	3/5/2002	**Details on changes in Account 921 from 2000 to 2001**	
		xhibit : Late Filed 17	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	71	3/5/2002	**Details on monthly on-peak & off-peak prices for MAPP (1998-2001)**	
		xhibit : Late Filed 16	By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	72	3/5/2002	**Cover letter re Late Filed Exhibits 16 - 20**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	73	2/25/2002	**PSC Staff Presentation**	
		Exhibit : 3	By Public Service Commission	35
*	74	2/25/2002	**Response to Data Request No. 5**	
		Exhibit : 8	By Montana-Dakota Utilities Co., a Division of MDU Re	3
*	75	2/25/2002	**Table 1, Prices & Intercontinental Exchange Forward Electricity Prices**	
		Exhibit : 9	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	76	2/25/2002	**MDU Pool Sales Calculation**	
		Exhibit : 10	By Montana-Dakota Utilities Co., a Division of MDU Re	1

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	Doc#	Filed		Pages
*	77	2/25/2002	**Reliability Assessment, 2001-2010**	
		Exhibit : 11	By Montana-Dakota Utilities Co., a Division of MDU Re	3
*	78	2/25/2002	**Selected gas utilities companies data for most recent calendar year**	
		Exhibit : 12	By Montana-Dakota Utilities Co., a Division of MDU Re	1
*	79	2/25/2002	**MAPP 2001 update to the 2000 regional plan**	
		Exhibit : 13	By Montana-Dakota Utilities Co., a Division of MDU Re	41
*	80	2/25/2002	**Public Utilities Reports, Advance Sheets**	
		Exhibit : 14	By Montana-Dakota Utilities Co., a Division of MDU Re	9
*	81	2/26/2002	**Table 1, Completed & Sited New Power Plants in MAPP**	
		Exhibit : 15	By Montana-Dakota Utilities Co., a Division of MDU Re	6
*	82	3/13/2002	**Original - Transcript of Hearing Volume I taken 2/25/02**	
			By Emineth & Associates Court Reporters	0
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\84.doc	
*	83	3/13/2002	**Original - Transcript of Hearing Volume II taken 2/26/02**	
			By Emineth & Associates Court Reporters	0
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\85.doc	
	84	3/13/2002	**Copy - Transcript of Hearing Volume I taken 2/25/02 & diskette**	
			By Emineth & Associates Court Reporters	0
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\84.doc	
	85	3/13/2002	**Copy - Transcript of Hearing Volume II taken 2/26/02**	
			By Emineth & Associates Court Reporters	0
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\85.doc	
	86	3/28/2002	**Letter to consulting service re closing out consulting contract**	
			By Mike Diller Public Service Commission	1
*	87	4/2/2002	**Proposed Findings of Fact, Conclusions of Law and Order**	
			By Public Service Commission	15
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\87.doc	
*	88	4/2/2002	**Cover letter re Proposed Findings**	
			By Public Service Commission	1
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\88.doc	
*	89	4/2/2002	**Brief of Montana-Dakota Utilities Co.**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	14
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\89.doc	
*	90	4/2/2002	**Proposed Finding of Fact, Conclusions of Law and Order**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	11
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\90.doc	
*	91	4/2/2002	**Cover letter re filings**	
			By Wm. Pearce, Counsel Montana-Dakota Utilities Co., a Division of MDU Re	1
*	92	4/4/2002	**Staff Response to Brief of MDU**	
			By Public Service Commission	10
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\92.doc	
*	93	4/4/2002	**Cover letter re Staff Response to Brief of MDU**	
			By Wm. Binek Public Service Commission	1
	\\Regulator\Case Mgmt\OrderLib\2001\010186\		\\Regulator\Case Mgmt\Orderlib\2001\010186\93.doc	
*	94	4/10/2002	**Additional information on summary of A&G salaries**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2
*	95	4/16/2002	**Affidavit of Tery L Blinsky**	
			By Montana-Dakota Utilities Co., a Division of MDU Re	2

* denotes certified to courts

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2000 Electric Operations
Annual Report Catagory Reports
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	Doc#	Filed		Pages
*	96	4/16/2002	**Request for case to be held open for purposes of settlement negotiations** By William P Pearce, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	1
*	97	4/18/2002	**Commission Advocacy Staff's response to Terry L Blinsky's Affidavit** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\97.doc	1
*	98	4/22/2002	**Letter notifying Commission of termination of settlement negotiations** By Wm. Binek Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\98.doc	1
*	99	4/24/2002	**Concurring Opinion by Commissioner Clark** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	2
*	100	4/24/2002	**Concurring Opinion by Commissioner Wefald** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	1
*	101	4/24/2002	**Findings of Fact, Conclusions of Law and Order** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\101.doc	16
*	102	4/24/2002	**Motion** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\OrderLib\2001\010186\102.doc	1
	103	4/26/2002	**Affidavits of Service** By Public Service Commission \\Regulator\Case Mgmt\OrderLib\2001\010186\ \\Regulator\Case Mgmt\Orderlib\2001\010186\103.doc	5
	104	4/25/2002	**Notice of Motion on Application for a Stay** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	1
	105	4/25/2002	**Application for Stay and Brief in Support Thereof** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	29
	106	4/25/2002	**Undertaking on Appeal to District Court** By Montana-Dakota Utilities Co., a Division of MDU R€	1
	107	4/25/2002	**Notice of Appeal and Specifications of Error - Civil No. 08-02-C-01719** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	2
	108	4/29/2002	**Amended Notice of Motion on Application for a Stay** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	3
	109	4/29/2002	**Affidavit of Personal Service** By Dan Kuntz, Attorney Montana-Dakota Utilities Co., a Division of MDU R€	1

Total Pages: 733
Certified Pages: 655

STATE OF NORTH DAKOTA

IN DISTRICT COURT

COUNTY OF BURLEIGH

SOUTH CENTRAL JUDICIAL DISTRICT

Montana-Dakota Utilities Co., Appellant,	
v.	**CIVIL NO. 08-02-C-01719 AFFIDAVIT OF SERVICE BY REGULAR MAIL**
North Dakota Public Service Commission,	
Appellee.	
PSC Case No. PU-399-01-186	

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

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **30th** day of **April 2002,** she deposited in the United States Mail, Bismarck, North Dakota, **1** envelopes with first-class postage fully prepaid, securely sealed and each containing a photocopy of:

1. **Notice to Appellant of Estimated Costs**

2. **Affidavit of Mailing**

The envelopes were addressed as follows:

Daniel S. Kuntz
Zuger Kirmis & Smith
P O Box 1695
Bismarck, ND 58502-1695

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Jessica L. Scott

Subscribed and sworn to before me this **30th** day of **April 2002.**

Susan K. Richter

Notary Public

SEAL

SUSAN K. RICHTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 15, 2004

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

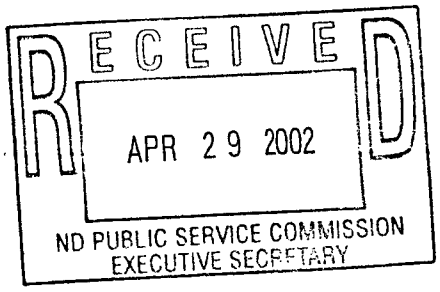
Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

AFFIDAVIT OF PERSONAL SERVICE



The undersigned, being first duly sworn on oath, deposes and says that I am a United States citizen and on April 25, 2002, I hand-carried to the office of Attorney General Wayne Stenehjem, Civil Litigation Division, 500 North 9th Street, Bismarck, ND and office of the North Dakota Public Service Commission, State Capitol, 600 East Boulevard, and personally served a copy upon those offices of the following:

1. **Notice of Appeal and Specifications of Error;**
2. **Undertaking on Appeal;**
3. **Application for Stay and Brief in Support Thereof; and**
4. **Notice of Motion on Application for Stay.**

Betty H. Metz

Subscribed and sworn to before me, this 25th day of April, 2002, a Notary Public for the County of Burleigh, State of North Dakota.
My Commission expires: 9/28/05

Karol A. Cossette

Karol A. Cossette

109 PU-399-01-186 Pages: 1

Affidavit of Personal Service

by Montana-Dakota Utilities Co., a Division of MDU Re

04/29/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

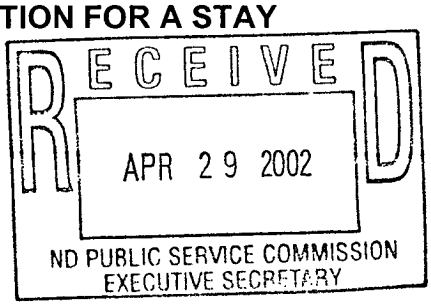
Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

AMENDED NOTICE OF MOTION ON APPLICATION FOR A STAY



TO: THE PUBLIC SERVICE COMMISSION AND ITS ATTORNEYS.

PLEASE TAKE NOTICE that the undersigned will bring the attached motion on for hearing before the Court before the Honorable Burt L. Riskedahl, in the Burleigh County Courthouse in the City of Bismarck, at 1:30 p.m., on May 2, 2002, or as soon thereafter as counsel can be heard.

You are required to serve before the date of the hearing all returns and supporting instruments to be used at the hearing.

Dated this 26th day of April, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ID #03490)

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Amended Notice of Motion on Application for a Stay by Montana-Dakota Utilities Co., a Division of MDU Re

04/29/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

COUNTY OF BURLEIGH

IN DISTRICT COURT

SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

AFFIDAVIT OF MAILING

STATE OF NORTH DAKOTA)
) ss
COUNTY OF BURLEIGH)

The undersigned, being duly sworn, deposes and says that I am a United States citizen, over 18 years of age, and on April 26, 2002, I served a copy of the attached:

AMENDED NOTICE OF MOTION ON APPLICATION FOR A STAY

by placing a true copy in a postage paid envelope addressed to each person named below, at the address stated below, which is the last known address of the addressee, and by depositing said envelope in the United States mail at Bismarck, North Dakota.

Jon Mielke, Executive Secretary
ND Public Service Commission
12th Floor
State Capitol
Bismarck, ND 58505-0480

Doug Bahr
Assistant Attorney General
Department 125
900 East Boulevard
Bismarck, ND 58505-0041

Karol A. Cossette

Subscribed and sworn to before me April 26, 2002, a Notary Public for the County of Burleigh, State of North Dakota. My Commission expires: 9-5-04

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APR 25 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA) IN DISTRICT COURT

COUNTY OF BURLEIGH) SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. _____

Montana-Dakota Utilities Co.,	)	
	)	**NOTICE OF APPEAL**
Appellant,	)	**AND SPECIFICATIONS OF**
	)	**ERROR**
-vs-	)	
	)	
North Dakota Public Service Commission,	)	
	)	
Appellee.	)	

TO: PUBLIC SERVICE COMMISSION AND ITS ATTORNEYS

PLEASE TAKE NOTICE that Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("MDU") appeals to the District Court for Burleigh County, South Central Judicial District, from an Order of the North Dakota Public Service Commission dated April 24, 2002 directing MDU to reduce its retail electric rates in North Dakota by an annual amount of $4.273 million.

MDU specifies the following errors as the grounds upon which the appeal is taken:

1. The Commission's findings of fact imputing wholesale electric sales margins to MDU's net operating revenues for the 2002 test year based on a three year historical average of such margins is not supported by a preponderance of the evidence, is arbitrary, and does not sufficiently address the evidence presented to the Commission by MDU.

2. The Commission's conclusion of law that MDU's existing electric rates yield excess revenues of $4.273 million per year is not supported by its findings of fact or a preponderance of the evidence.

3. The Commission's order directing MDU to file revised tariff sheets reflecting an across-the-board reduction to produce a total annual rate revenue decrease of $4.273 million is not in accordance with the law and is not supported by its findings of fact or a preponderance of the evidence.

Dated this 25th day of April, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ND #03490)

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STATE OF NORTH DAKOTA IN DISTRICT COURT

COUNTY OF BURLEIGH SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. _____

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

UNDERTAKING ON APPEAL TO DISTRICT COURT

The undersigned attorneys for the appellant Montana-Dakota Utilities Co. deposit with the Clerk of the above named Court, pursuant to N.D.C.C. § 28-32-42, a check in the amount of Two-Hundred Fifty Dollars ($250.00) as an undertaking in this proceeding to the State of North Dakota as obligee upon the conditions that Montana-Dakota Utilities Co. will prosecute the appeal herein without delay and pay all costs adjudged against Montana-Dakota Utilities Co. in the District Court.

Dated this 25th day of April, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ID #03490)

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Undertaking on Appeal to District Court

by Montana-Dakota Utilities Co., a Division of MDU R

04/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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STATE OF NORTH DAKOTA IN DISTRICT COURT

COUNTY OF BURLEIGH SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. _____

Montana-Dakota Utilities Co.,	
	APPLICATION FOR STAY AND
Appellant,	**BRIEF IN SUPPORT THEREOF**
-vs-	
North Dakota Public Service Commission,	
Appellee.	

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., ("MDU") applies to the Court, pursuant to N.D.C.C. § 28-32-48, for a stay of an order issued by the North Dakota Public Service Commission ("PSC" or "Commission") dated April 24, 2002 which directs MDU to reduce its North Dakota electric retail rates by an annual revenue amount of $4.273 million effective May 8, 2002. Attachment 1. MDU has appealed from that order and by this Application requests the Court to stay operation of the Commission's order pending a final order of the Court on the appeal.

FACTS

MDU is a utility company providing retail electric service to approximately 70,000 customers in North Dakota. The proceeding before the Commission was initiated by its staff which filed a complaint on September 7, 2001 requesting the Commission to order a reduction of MDU's electric rates. A hearing on the complaint was held February 25 and 26, 2002 in Bismarck. The parties presented evidence based upon a 2002 "test year" which established the required level of total net income necessary for MDU to realize a reasonable rate of return on its utility investment used to provide electric service to its

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Application for Stay and Brief in Support Thereof
by Montana-Dakota Utilities Co., a Division of MDU Re

North Dakota customers. Based upon the evidence, the Commission determined MDU's net electric utility investment in North Dakota for the 2002 test year, a reasonable rate of return on that investment, and the resulting amount of net income needed to realize that rate of return on the investment. Although MDU does not agree with all the Commission's determinations on these issues, it is not challenging those determinations by its appeal. A second aspect of the order was a determination of the projected actual net income that MDU would realize from its current electric rates during the 2002 test year. To reach that number, the Commission made several findings regarding MDU's 2002 test year projected revenues and expenses to arrive at the test year's projected net income. With the exception of the Commission's determination of projected wholesale net revenues, MDU does not challenge these findings by its appeal. MDU does, however, challenge the Commission's determination regarding the level of net revenues to be received by MDU during the test year from wholesale electricity sales to other parties. This was a major issue of disagreement in the proceeding before the Commission and also the subject of considerable expert testimony presented by MDU. The Commission ignored that expert testimony and instead relied upon a projection of wholesale net revenues suggested by the Commission staff witness based upon a three year historical average of such net revenues. The Commission adopted this historical average notwithstanding that the witness acknowledged it was arbitrary and not reflective of current wholesale market conditions. This adjustment was the basis for a reduction of $3.475 million of the total $4.273 million rate reduction ordered by the Commission. The Commission ordered this reduction to become effective for electric service rendered on and after May 8, 2002. MDU requests

a stay of the Commission's order pending MDU's appeal. Alternatively, MDU requests a stay of that portion of the ordered reduction relating to the Commission's determination of the projected level of wholesale net revenues.

APPLICATION FOR STAY

MDU's appeal is governed by the Administrative Agencies Practices Act at N.D.C.C. Chapter 28-32 as well as N.D.C.C. § 49-05-14. Specifically, N.D.C.C. § 28-32-48 provides in pertinent part:

> An appeal from an order or the rulemaking action of an administrative agency does not stay the enforcement of the order or the effect of a published rule unless the court to which the appeal is taken, upon application and after a hearing or the submission of briefs, orders a stay. The court may impose terms and conditions for a stay of the enforcement of the order or for a stay in the effect of a published rule.

With respect to the terms and conditions to be imposed with a stay of an order of the PSC regarding utility rates, N.D.C.C. § 49-05-14, provides:

> In case the order or decision of the commission is stayed or suspended, the order of the court shall not become effective until a suspending bond first shall have been executed and filed with and approved by the district court, payable to the state of North Dakota, and sufficient in amount and security to ensure the prompt payment, by the party appealing, of all damages caused by the delay in the enforcement of the order or decision of the commission and of all monies which any person, corporation, or limited liability company may be compelled to pay, pending the appeal, for transportation, transmission, product, commodity, or service in excess of the charges fixed by the order or decision of the commission, in case said order or decision is sustained. The district court, in case it stays or suspends the order or decision of the commission in any manner affecting rates, also by order shall direct the public utility affected to pay into court, from time-to-time, there to be impounded until the final decision of the case, or into some bank or trust company paying interest on deposits, under such conditions as the court may prescribe, all sums of money which it may collect from any corporation, limited liability company, or person in excess of the sum which such corporation, limited liability company, or person would have been

> compelled to pay if the order of the commission had not been stayed or suspended. Upon a final determination of an appeal, the court shall make an appropriate order disposing of the impounded funds in accordance with such determination. In the event the public utility shall fail to comply with the conditions of the stay bond, the commission may sue thereon for the use and benefit of the patrons or others who have suffered damage by reason of the stay.

MDU is prepared to comply with the conditions of N.D.C.C. § 49-05-14 by executing and filing a suspending bond and paying into escrow at a bank or trust company the revenues collected by MDU in excess of the rates ordered by the Commission.

Unlike N.D.R.Civ.P. Rule 62, governing a stay on appeal from a judgment of the district court, N.D.C.C. § 28-32-48 does not provide any other standards or guidelines for the issuance of a stay of an order of an administrative agency. The Administrative Agencies Practices Act, however, generally relies upon the North Dakota Rules of Civil Procedure to fill in procedural gaps of the Act. See, N.D.C.C. § 28-32-21. The provisions of N.D.C.C. § 28-32-48 are similar to those of Rule 62(d) which allows the appellant from a judgment of the district court to obtain a stay by giving a supersedas bond approved by the court. This provision entitles an appealing party to a stay of enforcement of a judgment as a matter of right if a supersedas bond is filed with the court. 12 Moore's Federal Practice, § 62.03[1] (Matthew Bender 3d Ed.). Only when the posting of the bond will not protect the rights of the nonappealing party, will a stay not be granted. Id. at § 62.03[3][b]. In comparison, when the appellant seeks a stay of an injunction pending an appeal under Rule 62(c), the courts apply a test similar to that used in deciding whether to issue a preliminary injunction. Cass County Electric Cooperative v. Wold Properties, Inc., 253 N.W. 2d 323 (N.D. 1997). That is, a stay of an injunction pending appeal requires a

showing: (1) that the appellant is likely to succeed upon appeal; (2) that unless the stay is granted the appellant will suffer irreparable injury; (3) that no substantial harm will come to any party if the stay is granted; and (4) that no substantial harm to the public interest will result on account of the stay. Id. In this case, MDU does not seek to stay an injunction. Rather, MDU's appeal is in the nature of those described under Rule 62(d) or 62(j) in which the undertaking provides the assurance that the appellant will pay damages which the opposite party may sustain by not having the particular thing or act directed to be done by the judgment from which the appeal is taken. Accordingly, the Court should grant MDU's application for a stay effective with its compliance with N.D.C.C. § 49-05-14.

Even if the Court applies the four-part test applicable to a stay pending an appeal of an injunction, MDU meets the test to obtain a stay from the Commission's order.

1. Likely to succeed upon appeal.

The complaint against MDU's rates was brought by the staff of the PSC. Accordingly, the burden of proof was on the staff. The major dollar issue in contention was the net revenues expected to be received by MDU from wholesale electricity sales. Prior to 1997, the level of net revenues from these sales was relatively small. From 1996 through 1998, the net revenues from these sales increased from $1.916 million in 1996, to $2.492 million in 1997, and $4.817 million in 1998. See Direct Testimony of staff witness Mike Diller. Beginning in 1999 and extending to the first part of 2001, wholesale prices of electricity increased to unprecedented levels due to a supply/demand imbalance, an unprecedented increase in natural gas prices, and a serious shortage of electricity on the West Coast. As a result of reduced demand and increased generating capacity, wholesale

electricity prices dropped dramatically in the first part of 2001. The lower prices continue today and there was no testimony by any witness that the price levels experienced in 1999-2001 could be expected to reoccur in the foreseeable future. To the contrary, MDU presented expert testimony that the prices achieved in 2000-2001 were an anomaly and that the lower prices experienced today would continue for the foreseeable future. Notwithstanding the dramatic drop in prices in the first part of 2001, MDU was fortunate enough to have executed a six month wholesale contract early in 2001 which provided for wholesale electricity sales at the high prices that existed at the time the contract was signed. As a consequence, MDU's net revenues from wholesale sales in 2001 reached $15.938 million – more than triple the level received only three years earlier. Without any evidence or expectation that the 2000-2001 price levels would continue into the future, the Commission staff first recommended that the Commission impute the 2001 level of wholesale net revenue to the test year for purposes of setting future retail rates. MDU provided expert testimony, however, that based upon foreseeable market conditions including actual sales during the last part of 2001 and the first months of 2002, as well as electricity futures prices which everyone acknowledged were reliable indicators of near-term prices, MDU's expected net revenue from wholesale sales would be $6.430 million during the 2002 test year.

In the face of decreased existing prices and no evidence supporting an assumption that the price spike of 2000-2001 would be realized on any sustained basis in the foreseeable future, the staff presented what it viewed as a more reasonable recommendation for imputing wholesale net revenues using an average of the most recent

three years of historical results. The staff recommended that the Commission impute net wholesale revenues of $11.696 million to the test year rather than its previous recommendation of $15.938 million or the company's projection of $6.430 million. Of course, there was no more evidence supporting this recommendation than there was evidence to support continuation of the 2001 net revenue level. Indeed, the staff witness candidly acknowledged that the use of the three year historical average was arbitrary. Attachment 2. By including in its three year historical average those portions of 2000-2001 in which the price anomaly occurred, the staff's average net revenue bears no relation to any reasonable expectation of the future and is unsupported by any evidence of realizable sales. Indeed, the staff's recommended level of imputed net wholesale revenues has never been realized by MDU in any year other than 2001. The staff nevertheless sought to support its recommendation by suggesting the resulting rates from this proceeding might remain in effect for 15 years since that was the period of time since MDU's electric rates were last changed by the PSC. This rationale violates principles of utility ratemaking which require that rates be set based upon known and measurable conditions as they exist or are projected to exist during the test year. More importantly, North Dakota law prohibits consideration of test year information or conditions more than twenty-four months after the date new rate schedules are filed. N.D.C.C. § 49-05-04.1. Rationalizing an imputation of revenues based upon unspecified events that might occur 10-15 years into the future goes beyond even speculation.

Because the Commission staff had the burden of proof in this proceeding and because there is no evidence supporting a finding or conclusion that a three year historical average of wholesale net revenues would be realized during the test year, and because the Commission did not sufficiently address the evidence presented by MDU, the Commission's findings and conclusions are not supported by a preponderance of the evidence. Accordingly, MDU is likely to prevail on the merits of its appeal.

2. Unless the Stay is Granted, MDU Will Suffer Irreparable Injury.

The financial impact on MDU of the imputation of wholesale net revenue based upon the staff's recommended three year historical average rather than MDU's market-based estimate of such revenue is $3.475 million. If a stay is not granted and MDU is required to reduce its rates, it will lose net annual revenues of that amount even if it ultimately prevails on its appeal. Because MDU will have no way of recovering those lost revenues from its customers or the PSC, that revenue will be forever lost to MDU and it will be irreparably harmed.

3. No Substantial Harm Will Come to Any Party if the Stay is Granted.

The only other party to this proceeding is the PSC. Obviously, a stay of its order will have no financial impact or other negative effect on the PSC. As will be discussed in the next section, the interests of MDU's customers will be protected during the appeal by the bond to be filed by MDU and the escrowing of the revenues MDU will receive as a result of the stay.

4. No Substantial Harm to the Public Interest Will Result on Account of the Stay.

Public Interest in this case relates to MDU's customers who will continue to pay the current MDU electric rates during the appeal if the stay is granted rather than the reduced rates ordered by the Commission. N.D.C.C. § 49-05-14, however, fully protects these customers by requiring not only a suspending bond, but also the escrowing of the additional collected revenue. In the event that MDU does not prevail on its appeal, it will refund these escrowed amounts, with the earned interest, to its customers. This refund mechanism is commonly used in situations when it is determined customers are entitled to receive a refund from a public utility. As an alternative, and to further protect the public interest, MDU is willing to limit the stay of the PSC order to only that portion of the rate reduction that relates to the imputed wholesale net revenue. With the concurrence of the PSC and the Court, MDU would implement the balance of the ordered rate reduction of approximately $800,000 effective May 8 as directed by the Commission.

CONCLUSION

By its commitment to submit a suspending bond and escrow additional revenues collected as a result of a stay, MDU is entitled to a stay of the Commission's order pending the appeal. Even if the Court determines that MDU must meet the showing required to stay an injunction pending appeal, MDU has made that showing and is accordingly entitled to a stay of the Commission's order. Upon approval of MDU's application for a stay, it will file a suspending bond and establish an escrow account with a local financial institution. MDU respectfully requests the Court to issue a stay of the Commission's order subject to MDU's compliance with the conditions of N.D.C.C. § 49-05-14.

Dated this 25th day of April, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ID #03490)

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

April 24, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schulz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On September 7, 2001, the North Dakota Public Service Commission advocacy staff (staff) filed a complaint against Montana-Dakota Utilities Co. (MDU), a division of MDU Resources Group, Inc., alleging that MDU's current rates result in excess revenue collections of $9.155 million per year. Also on September 7, 2001, staff filed its testimony in support of its complaint.

On September 19, 2001, the North Dakota Public Service Commission (Commission) found that staff's complaint states a *prima facie* case and served the complaint on MDU.

On November 5, 2001, Commissioner Susan Wefald wrote to the parties regarding the applicability of handling off-system sales revenue through the fuel

adjustment clause and asking whether the Commission should consider incentives to encourage future off-system sales. On November 21, 2001, staff' replied, asserting that no change in existing policy should be made, thereby excluding off-system sales profits from the fuel adjustment clause. Staff also provided information regarding a number of incentive plans used by other state commissions to encourage the selling of off-system sales. On December 3, 2001, MDU replied stating that any discussions of this issue should focus on the need for incentives and a proper balance of the risks and rewards.

On November 13, 2001, MDU filed a letter confirming the procedural schedule agreed to orally by MDU and staff.

On November 21, 2001, the Commission issued a Notice of Hearing and Notice of Public Input Session. The notice set forth the following issues for consideration in the proceeding:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On December 11, 2001, the Commission conducted a Public Input Session via interactive videoconference, with hearing sites in Bismarck, Dickinson and Williston. The public input included concerns about escalating prices requiring the lowering of thermostats, a commendation for reliable service, questions concerning changes in company wide earnings and stock prices, concerns about the workability of investor owned utilities in conjunction with rural electric cooperatives and, general questions about deregulation and alternative forms of regulation. Staff and MDU responded to all questions.

On January 11, 2002, MDU's six witnesses filed direct testimony asserting that rates do not need to be changed.

On February 11, 2002, staff's two witnesses filed its rebuttal testimony reducing its initial complaint of excess earnings from $9.155 million to $7.327 million.

On February 19, 2002, MDU added four new witnesses and filed its surrebuttal testimony arguing that rates do not need to be changed.

On February 25 and 26, 2002, the Commission conducted a formal hearing as scheduled. No motions to intervene were filed. On March 5, 2002, MDU filed late-filed exhibits.

On March 5, 2002, MDU filed Late Filed Exhibit 16 providing monthly on-peak prices for MAPP for the period 1998 through 2001, Late Filed Exhibit 17 providing details of changes in office supply expenses from 2000 to 2001, Late Filed Exhibit 18 an updated summary of insurance expense for 2001 and projected 2002, Late Filed Exhibit 19 providing information on corporate aircraft expense, and Late Filed Exhibit 20 providing details of the change in administrative and general salaries between 2000 and 2001.

On April 10, 2002, MDU filed an update to Late Filed Exhibit 20 to include administrative and general salaries for 1999.

On April 16, 2002, MDU submitted an affidavit of Terry L. Blinsky, Electric Bulk Power Marketing Coordinator for MDU, containing first quarter 2002 wholesale sales and sales for resale margin. MDU requested that this information be made part of the record. MDU also requested that Case No. PU-399-01-186 be held open temporarily for the purposes of settlement negotiations which MDU had initiated with the Commission Staff.

On April 18, 2002, Commission staff filed a response to the affidavit of Terry L. Blinsky stating no objection generally to the filing of the information except to the relevance and subject of paragraph 5 of affidavit.

On April 22, 2002, Commission staff filed a letter stating that it could not reach a settlement agreement with MDU.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company operating as a division of MDU Resources Group, Inc. MDU provides retail electric service to approximately 70,000 customers in North Dakota.

2. Advocacy staff witness Mike Diller, Public Service Commission Director of Accounting, identified the primary components of rate of return regulation as rate base, cost of capital and net regulated income. He explained how the components are used to determine if MDU's rates should be adjusted and provided the Commission with worksheets for use in its deliberations.

3. Except for the specific exceptions noted below, the parties do not dispute the:

- 2002 test year for rate determination
- Jurisdictional cost of service study.
- Test year rate base.
- Capital structure.
- Cost of preferred equity.
- Test year revenues (except for sales for resale margins).
- Test year expenses (except for administrative and general expenses).

Test Year Rate Base

4. Diller presented historical rate base amounts reported by MDU and 2002 test year rate base levels for this proceeding. MDU agreed to Diller's test year value for rate base. The commission finds the following historical rate base levels and 2002 test year rate base:

	(Thousands)			
	Reported by MDU			2002
Description	1999	2000	2001	Test Year
Plant in Service	$366,890	$375,347	$379,126	$381,289
Accum. Res. for Depreciation	193,286	202,071	215,094	215,130
Avg. Net Plant in Service	$173,604	$173,276	$164,032	$166,159
Constr. Work in Progress	2,572	850	518	518
Materials & Supplies	3,252	3,202	2,909	2,909
Fuel Stocks	1,192	1,277	1,255	1,255
Prepayments	265	209	99	107
Net Negative Salvage				
Accum. Def. Income Taxes	(42,124)	(41,564)	(39,774)	(39,807)
Accum. Invest. Tax Credits	(3,583)	(3,074)	(2,229)	(2,229)
Customer Advances	(309)	(509)	(10)	(10)
Average Rate Base	$134,869	$133,667	$126,800	$128,902

5. The parties dispute the following issues:

- The return on common equity.
- The overall cost of long-term debt.
- The appropriate level of sales for resale margins.
- The appropriate level of administrative and general expenses.

Return on Common Equity

6. The parties dispute the return on common equity (ROE) MDU should be allowed an opportunity to earn.

7. MDU's witness, Steven Gaske, asserted that a return on equity of 12.75% is a fair and reasonable return to MDU's stockholders using a Discounted Cash Flow (DCF) calculation.

8. Staff's witness, Charles King, asserted that a return on equity of 11.7% is a fair and reasonable return to MDU's stockholders using a DCF calculation.

9. During cross-examination, Gaske reviewed the annual survey of returns on equity granted by other state commissions as reported in the Public Utilities Reports for the year ended September 30, 2001. After reviewing the reports, Gaske noted that of the 45 companies listed, eleven companies were granted returns on equity higher than 11.7% and only three companies were granted returns on equity that were equal to or higher than 12.75%.

10. Two primary areas of disagreement, resulting in different recommended rates of return on common equity, include:

- Flotation costs.
- Comparable companies.

Flotation Costs

11. Flotation costs are the costs associated with issuing new common equity capital and make up approximately 58 basis points of difference between MDU's and staff's positions. Eliminating the flotation cost from Gaske's calculation reduces his recommended return on equity to 12.17%.

12. Staff's position included a review of floatation costs actually incurred during the past five years. King found that the actual costs were immaterial and lost in the rounding when applied to the return required on common equity. As a result, staff did not include any flotation costs in its return on equity calculation.

13. Rather than using actual expenditures, MDU witness Gaske included a theoretical cost of issuing common equity based on a sampling of electric companies during 1996-2000. Gaske assumed flotation costs of 4.75% for new equity which he incorporated in his proposed return on equity.

14. Under cross-examination, Gaske provided no empirical data to show that disallowing flotation costs would hinder the issuance of stock. On the contrary, Gaske agreed that most regulatory commissions do not allow flotation costs.

15. Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs in the instant case. Therefore, the Commission will not include flotation costs in the determination of return on common equity.

Comparable Companies

16. Staff witness King used a DCF analysis to estimate the cost of common equity. King testified that if the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit (comparable earnings test). For the comparable earnings test, King identified companies that have a bond rating of BBB or better from Standard & Poors and Baa or better from Moody's, companies of broadly comparable size, companies that have $100 million or more in gross revenue, and companies whose market risk is driven by the earnings from providing regulated utility services, including retail electric service. King identified eight combination gas-and-electric companies and four electric-only companies with at least 85 percent of revenue generated by regulated activities. King testified that the comparison companies should be comprised of eight combination gas-and-electric companies since MDU is a combination gas and electric utility company. King used a "interest rate risk premium" check to test his DCF conclusions for reasonableness.

17. MDU witness Gaske used 12 companies including both electric-only and combination (gas and electric) companies for his DCF analysis. The 12 companies used met Gaske's threshold of 75 percent of revenue from regulated retail revenue. Gaske asserts that because this proceeding is about MDU's electric operations, the comparison group should also include electric only companies. Gaske used a risk premium approach known as the Ibbotson & Singfield study and also the "alternative equity investment approach" to test his DCF conclusions for reasonableness.

18. Staff asserts that the comparison companies should be comprised of combination gas and electric companies because MDU is a combination gas and electric utility company. Gaske asserts that because this proceeding is about MDU's electric operations, the comparison group should also include electric only companies.

19. Montana-Dakota Utilities Co. is a division of Montana-Dakota Resources Group, Inc. As such, any common stock issuance or dividend paid is done so by Montana-Dakota Resources Group, Inc., a combination gas and electric company.

20. We find that the list of comparable companies should consist of companies with 85 percent or more of revenue from revenue generated by regulated activities. We find merit in MDU's assertion that electric-only companies should be used to determine the cost of equity capital that is devoted to providing regulated retail electric service in North Dakota. However, we find that MDU compromises this philosophy by including combination gas-and-electric companies in its calculation. We also find merit in staff's assertion that the list of comparable companies must consist of combination gas-and-electric companies since MDU is a combination company, however, the comparable companies should perhaps have the same relative proportions of electric-to-gas business as MDU.

21. We conclude that the list of comparable companies for this proceeding should consist of both electric-only and combination gas-and-electric companies with 85 percent or more of revenue from revenue generated by regulated activities. Accordingly, we find that a return on equity of 11.8% is a fair and reasonable return on equity to MDU's stockholders.

Weighted Cost of Long-Term Debt

22. The parties dispute the overall cost of long-term debt. MDU proposes a weighted cost of 9.22% whereas staff advocates a weighted cost of 8.62%.

23. Diller testified that MDU's reported cost of debt since 1988 remains significantly higher than the cost reported by the other two investor owned electric companies operating in North Dakota.

24. MDU witness Gaske testified that differences in the cost of debt are due to timing of financing needs and therefore are often explained by the vintage of the debt obligations.

25. Staff witness King testified an accounting-based cost of debt calculation. King recommended that debt issuance and redemption costs be amortized over the life of the debt issues, which results in MDU recovering all of its costs. Using an accounting-based cost, staff asserts that MDU's cost of debt is 8.62%.

26. MDU asserts a "yield-to-maturity" cost of debt calculation is more appropriate. Gaske testified that the yield to maturity calculation gives consideration to the time value of money..

27. We find the "yield-to-maturity" cost of debt calculation is more appropriate as it gives consideration to the time value of money.

28. The Commission finds that an overall weighted cost of capital of 10.24% for MDU is just and reasonable as follows:

	Cost of Capital		
Description	Capital Ratio	Cost	Weighted Cost
Long-Term Debt	45.90%	9.22%	4.23%
Preferred Stock	5.23%	4.63%	0.24%
Common Equity	48.87%	11.80%	5.77%
TOTAL	100.00%		10.24%

Sales for Resale Margins

29. The parties dispute the appropriate level of sales for resale margins. MDU proposes using 2001 sales levels combined with futures prices as of January 2002. Staff advocates using a 3-year historical average.

30. Staff testified that using an average of sales for resale margins during the past three years results in a normalized level of $11,695,641 on a total company basis. Diller's resale settlement calculation, offered at the hearing, shows that staff has reduced 2001 sales for resale margins by $2.8 million on a North Dakota basis for the 2002 test year.

31. The staff method of normalizing sales for resale margins is based on actual transactions that have occurred during the past 3 years and then averaged to result in a proxy for expected margins in the future.

32. MDU proposed using 2001 sales volumes and splitting the sales into off-peak and on-peak sales. The margins were then calculated by multiplying the off-peak sales by an estimated price and the on-peak sales by futures prices quoted by the NYMEX Cinergy Hub.

33. Diller identified 28 factors affecting future resale margins from the testimony of MDU's ten witnesses. One of the factors listed by Diller includes "new generation capacity." If price is determined by supply and demand principles discussed in this case, new electric supplies to meet new demand are critical to the long-term pricing of electricity. According to MDU's representation, the Mid-American Power Pool (MAPP) forecasts excess capacity in the future. However, Exhibit 11 entered by Commissioner Wefald shows that the North American Electric Reliability Council suggests that the MAPP capacity is inadequate for the time period of 2001-2010. This indicates that the experts can't agree on the critical element of the supply side of the price equation.

34. With respect to the demand side of the price equation, staff asserts that determining sales for resale margins based primarily on futures prices of the day is unreasonable.

35. MDU splits its margins calculation between off-peak and on-peak sales. Diller questioned the calculation in his rebuttal testimony because the off-peak sales margins portion reflects a net loss contribution to earnings of $144,319. Blinsky testified that it is not MDU's common practice to sell below the incremental cost of fuel. Blinsky further asserted that his calculation uses average fuel costs and that during off-peak periods the off-system sales typically come from a specific unit.

36. Diller stated in his rebuttal testimony that staff requested source data for Blinsky's off-peak prices. According to Diller's testimony, MDU replied that the off-peak prices are estimates based on recent experience. Diller continued in his rebuttal testimony that without the source data and some historical perspective, staff is unable to conclude anything from MDU's sales for resale margins calculation.

37. MDU calculated on-peak margins by multiplying 2001 sales volumes by the futures prices listed by NYMEX on a particular day. Diller testified that futures are going be less likely to predict actual electricity prices the further out you go. Gaske testified that the futures prices are the best estimate of what electricity will cost in the future and that the futures prices consider all the factors that affect the price of electricity.

38. In its April 16, 2002 filing, MDU witness Blinsky states that the level of wholesale sales for the period January 1, 2002 through March 31, 2002 was 226,353 Mwh as compared to 260,830 Mwh sold in the first quarter of 2001. Blinsky further states that the level of sales for resale margins for the period January 1, 2002 through March 31, 2002 was $1,618,840 as compared to the $4,126,072 sales for resale margin for the first quarter of 2001.

39. Staff has shown, based on historical evidence, that MDU has made significant margins in its sales for resale. MDU has attempted to predict reduced sales for resale margins through estimates of future sales and future prices.

40. The Commission finds a high degree of uncertainty associated with predictions that are affected by one or more of at least 28 factors and the large number of combinations of those factors that are outside MDU or Commission control. These factors can change dramatically as evidenced by the change in prices of natural gas in recent years. We find that using the average of sales for resale during 1999, 2000, and 2001 is most appropriate decision at this time.

Administrative and General Expenses

41. The parties dispute the appropriate level of administrative and general expenses. MDU proposes a 12.3% increase compared to 2001 levels. Staff proposes a 4.6% reduction compared to 2001 levels.

42. The administrative and general (A&G) expense category includes a number of accounts including salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, regulatory Commission expenses, general advertising, miscellaneous general, rents and the maintenance of general plant.

43. Staff presented evidence at the hearing that MDU's A&G expenses had been declining since 1996 until the year ended 2000. MDU reported a 12.4% increase in A&G expenses in 2001 and MDU now asserts that a 12.3% increase for 2002 is justified.

44. Staff asserted that MDU's testimony does not provide an analytical approach to quantifying future estimated costs and therefore the A&G expense increase sponsored by MDU should be rejected.

45. Four general areas of concern were identified with respect to A&G expenses including MDU's projection of A&G salaries, office supplies expense, insurance expense and pensions and benefits.

A&G Salaries

46. Staff noted a significant increase in the salaries account of A&G expenses from 2000 to 2001. Staff did not originally take exception to the expense level because staff assumed that the difference was due to different levels of salary capitalization from one year to the next. Under cross-examination, MDU witness Ball was not sure why A&G salaries increased so much but thought it had to do with the capitalization differences as well. Through cross-examination, Ball agreed to research the difference and file Late Filed Exhibit No. 20. Late Filed Exhibit No. 20 discloses that a significant portion of the difference resulted from the payment of higher bonuses and commissions. The bonuses and commissions are $635,765 higher on a total electric company basis, more than double the year 2000 level. At the request of the Commission, MDU updated Late Filed Exhibit 20 to include 1999 data.

47. We find that 2001 A&G salaries expense level is significantly higher than previous years because the bonuses and commissions component of A&G salaries is significantly higher. We find that this level of bonuses and commission is unreasonable and should not be included in the 2002 test year. Therefore we find that an appropriate level of bonuses and commissions for the 2002 test year is an average of that expense for years 1999, 2000, and 2001.

Office Supplies Expense

48. The office supplies expense category includes such expenditures as automobile services, bank charges, books and subscriptions, building service, communications, office equipment, computer infrastructure, membership fees, office supplies, legal department expenses, postage and printing, travel and incidental expenses and corporate aircraft expenses.

49. Diller provided an exhibit showing office supplies expense for the years 1996 through 2001. Diller testified that normal office supplies expense is approximately $1.8 million to $2.1 million annually, but that actual expenditures for 2001 were reported to be $2.9 million. Staff proposed adding 5% to actual 2000 expenses, resulting in a 2002 test year level of $2.228 million.

50. MDU asserted that its reported level of office supplies expense in 2001 is a reasonable expense level for 2002.

51. Staff's position is that the expenditures included in office supplies expense are controllable. Staff testified that it is unreasonable to assume that one extremely high cost year is representative of future expense levels.

52. Staff asserted that MDU did not use an analytical approach to quantifying future estimated costs. Instead, MDU relied on the expenditure level of one high cost year (2001). Staff highlighted its concerns by pointing out that MDU attributes a substantial part of the increase to its new corporate aircraft and that MDU did not quantify the savings attributable to acquiring the aircraft.

53. The Commission agrees that office supply expenses are controllable by MDU. We find that 2001 office supply expense level is significantly higher than previous years and there is no evidence that the significantly higher year is representative of a reasonable test year expense level. The Commission finds that an fair and reasonable level of office supply expenses for the 2002 test year is an average of the office supply expenses for years 1999, 2000, and 2001.

Insurance Expense

54. MDU proposes an increase in North Dakota insurance expense of $155,383 to reflect higher 2002 premiums. MDU testified that the events on September 11, 2001, resulted in increased insurance costs and that the higher costs are reflected in the 2002 premiums.

55. Staff asserts that MDU's testimony did not include a review of all insurance expenditures and that MDU's evidence is inconclusive.

56. MDU Late Filed Exhibit 18 identifies the premiums that are expected to cause year 2002 increases.

57. The Commission finds that MDU's projected insurance expenses are reasonable for the 2002 test year.

Pensions & Benefits

58. Staff identified two areas of concern regarding MDU's proposed cost of pensions and benefits, as follows:

- Pension Expense and Post Retirement Expense (FAS 106)
- Supplemental Income Security Plan (SISP)

Pension and Post Retirement Expense

59. MDU witness Ball proposes an adjustment to pension expense and post retirement expense. Staff testified that it asked for source data related to the adjustments but the actuarial information was not provided. MDU offered to let Diller review the actuarial study on a confidential basis.

60. Diller concluded that both the pension expense and post retirement expense adjustments proposed by MDU do not include a review of all employee pension and benefits expenditures and are therefore inconclusive. Staff proposed using2001 expense levels as a reasonable level for the 2002 test year.

61. Ball testified that MDU has no knowledge of known changes to pension and post retirement expenses other than the 2002 actuarial studies. Ball asserted that the increase is attributable to low investment returns in recent years and the use of a lower discount rate for future years. He further testified that the increases for 2002 are real and currently being booked and that more increases are expected through 2005. MDU's case includes an upward adjustment to 2001 expense of $179,000 for pension expense and $62,000 for post retirement expenses.

62. Staff did not further dispute the increases for 2002 related to pension and post retirement expenses or whether said expenses are real and are currently being booked.

63. The Commission finds that the upward adjustment to 2001 expense of $179,000 for pension expense and $62,000 for post retirement expenses is reasonable for the 2002 test year.

Supplemental Security Income Plan (SISP)

64. MDU proposed to include expenses associated with SISP. MDU witness Richard Espeland testified that SISP is a supplemental pension benefit that is necessary to

attract, retain and provide equitable benefits for key employees. MDU asserts that various changes in federal regulations, Social security benefits, and employment practices have adversely affected MDU key employees. MDU points out that defined benefit pension plans, that in the past could include benefits in consideration of up to $225,000 of salary, have been limited to $200,000. 401(k) plan regulations limit employee contributions limiting the percentage of income a key employee can contribute as compared to a lower salaried employee. MDU also testified that the Social security covered wage base has not kept pace with the general wage inflation and benefits provided at higher income levels are significantly less than at lower income levels. In general, MDU asserts that the more traditional plans benefit the low paid employees more than the high paid employees on a percentage of income basis and SISP enables MDU's key employees to benefit on a more comparable basis when considering benefits as a percentage of income.

65. Diller characterized SISP as a double pension for MDU's few key employees and compared it to the Enron debacle and the payments Enron made to key employees. Diller noted that one of the Congressmen in the recent Enron hearings stated that payments to key employees looked like management taking care of itself. Diller observed that Enron provided a warning to all of us, especially to managers of companies.

66. Staff objects to including SISP in ratemaking expense. Diller testified that while the plan has been in effect since 1982, the company has never sought rate recovery in any subsequent electric or gas rate case. Staff opposes spending a million dollars a year for the benefit of a few employees. In addition to SISP, employees that are allowed to participate in SISP are paid very well (minimum of $75,000 to $80,000 per year) and participate in all the other benefits offered to regular employees such as health insurance, life insurance, 401k participation, profit sharing plans, incentive plans, defined benefit plans, social security and discounted gas and electric service for those living in MDU's service territory.

67. Diller testified that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. For instance, an employee making $50,000 a year would receive a monthly SISP benefit of $1,330 compared to a monthly benefit of $30,000 for the employee making $600,000 a year. In the case of the low-end employee, the monthly benefit calculates to be 2.66% of annual salary compared to the high-end employee who would receive a monthly benefit of 5% of annual salary. Diller noted that only 27 employees of MDU's gas and electric employees are considered to be key employees.

68. The Commission concludes it is inappropriate for ratepayers to bear this expense. The Commission finds that SISP expenses should not be included in ratemaking expense.

Earnings

69. The Commission finds the following historical summary of reported revenue and expenses, and the reasonable test year revenue and expenses, as follows:

	(Thousands)				
	Reported by MDU				
Description	1999	2000	2001	Adjustments	Test Year
Sales for Resale	$13,265	$15,034	$17,687	($2,800)	$14,887
All Other Revenues	80,657	81,929	84,415	0	84,415
Total Revenues	$93,922	$96,963	$102,102	($2,800)	$99,302
Production Expense	$37,160	$38,365	$40,671	($765)	$39,906
Transmission Expense	3,667	3,567	3,915	370	4,285
Distribution Expense	4,586	4,660	5,010	0	5,010
Customer Accounts	2,162	2,113	2,233	0	2,233
Customer Service & Info.	96	105	113	0	113
Sales Expense	258	269	281	0	281
Administration & General	8,303	8,154	8,968	(205)	8,763
Total O & M Expense	$56,232	$57,233	$61,191	($600)	$60,591
Depreciation	$11,436	$11,803	$11,955	$77	$12,032
Taxes Other Than Income	$3,936	$3,811	$4,019	$0	$4,019
Income Tax Expense	$6,319	$6,750	$7,955	($1,075)	$6,879
Net Regulated Income	$15,999	$17,366	$16,982	($1,201)	$15,781
Income Tax Calculation:					
Net Income Before Taxes	$22,318	$24,116	$24,937		$22,660
Less Interest Deduction:					
Rate Base	$134,869	$133,667	$126,800		$128,902
Weighted Cost of Debt	4.93%	4.74%	3.96%		4.23%
Calculated Interest Deduction	$6,644	$6,332	$5,017		$5,456
Other Tax Adjustments	$281	($743)	$163		$163
Taxable Income	$15,955	$17,041	$20,083		$17,368
Combined Tax Rate	39.61%	39.61%	39.61%		39.61%
Income Tax Expense	$6,319	$6,750	$7,955		$6,879

70. The Commission finds MDU's 2002 test year excess revenue of $4,273,000, as follows:

	(Thousands)
Description	Test Year
Average Rate Base	$128,902
ROR Required (11.8% ROE)	10.24%
Return Required	$13,201
Return Earned	$15,781
Return (Excess)	($2,580)
Tax Factor	1.656
Revenue (Excess)	($4,273)

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties in and the subject matter of this proceeding.

2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.

3. MDU's existing electric rates yield excess revenues of $4.273 million per year.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU shall implement an across the board rate reduction sufficient to produce a total annual rate revenue decrease of $4.273 million. MDU shall file revised tariff sheets reflecting the rate reduction to be effective for electric service rendered on and after May 8, 2002.

2. The April 16, 2002, request by MDU that the affidavit of Terry L. Blinsky be made part of the record in this proceeding is granted.

PUBLIC SERVICE COMMISSION

Anthony T. Clark **Commissioner**	**Susan E. Wefald** **President**	**Leo M. Reinbold** **Commissioner**

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.	:	Case No.
2000 Electric Operations	:	PU-399-01-186
Annual Report	:	

TRANSCRIPT OF

HEARING

VOLUME I

Taken At
State Capitol
Public Service Commission
Bismarck, North Dakota
February 25, 2002

BEFORE ALLEN C. HOBERG
-- PROCEDURAL HEARING OFFICER --

Attachment 2

A. That's correct.

Q. 2002 and beyond.

A. That's correct.

Q. Does that reflect your opinion that for rates that are going to be forward going to the future it's most appropriate to use the most recent information available?

A. Yes.

Q. Now in your discussion of sales for resale margin you indicated that there are lots of variables and many factors. In fact, I believe you listed a series of four pages of factors here that you think are pretty good ones, if I may quote you; is that correct?

A. I agree with the company that those factors do in fact affect the price of electricity.

Q. And you're recommending now, as I

understand your testimony, a three-year average of sales for resale margins as the appropriate benchmark?

A. That's true.

Q. What was the purpose for three? I mean, why not five to get a longer range analysis?

A. I guess you could -- you could go back ten years when there wasn't any resale margins, I guess, ten years ago, or none to speak of. To answer your question directly, it's just arbitrary. I don't think it would have made any difference to add another year because -- let's see, 1998 resale margins were still quite high, but if you went back five years, it would change it a little bit.

Q. And again, if I may quote you, I think you referred to 2001 as a hiccup in effect in the national economy, recognizing that the year 2001 is going to have some very unusual features about it.

A. Is that the word I used, hiccup?

Q. You did use hiccup, I think.

A. Okay. Yes, I guess I did.

Q. I'm not sure how to spell it, so I have it in my notes here probably misspelled. And you testified that trying to estimate prices in the future is based on a lot of variables and it's more

of an art than a science, but you would agree, however, would you not, that insofar as there are reasonable techniques to try to project these prices, it would be appropriate to use them?

A. Yes.

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COMMISSION

STATE OF NORTH DAKOTA) IN DISTRICT COURT

COUNTY OF BURLEIGH) SOUTH CENTRAL JUDICIAL DISTRICT

CIVIL NO. 08-02-C-01719

Montana-Dakota Utilities Co.,

Appellant,

-vs-

North Dakota Public Service Commission,

Appellee.

NOTICE OF MOTION ON APPLICATION FOR A STAY

TO: THE PUBLIC SERVICE COMMISSION AND ITS ATTORNEYS.

PLEASE TAKE NOTICE that the undersigned will bring the attached motion on for hearing before the Court before the Honorable Benny Graff, in the Burleigh County Courthouse in the City of Bismarck, at 1:30 p.m., on May 2, 2002, or as soon thereafter as counsel can be heard.

You are required to serve before the date of the hearing all returns and supporting instruments to be used at the hearing.

Dated this 25th day of April, 2002.

ZUGER KIRMIS & SMITH
Attorneys for Appellant
Montana-Dakota Utilities Co.
P.O. Box 1695
Bismarck, ND 58502-1695

By: _____
Daniel S. Kuntz (ID #03490)

104 PU-399-01-186 Pages: 1
Notice of Motion on Application for a Stay
by Montana-Dakota Utilities Co., a Division of MDU Re
04/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000-Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **26th day of April, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed, each containing a photocopy of:

Order

The envelopes were addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0005 8654 8853

William P Pearce
P O Box 400
Bismarck ND 58502-0400
Cert. No. 7001 2510 0005 8654 8846

Douglas W Schulz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7001 2510 0005 8654 8839

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **26th day of April, 2002**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **26th day of April, 2002**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, or sent by electronic mail, each containing a photocopy of:

Order

The envelopes and electronic mail were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon L Helbling

Subscribed and sworn to before me
this **26th day of April, 2002**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

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APPROVED
DATE: 4-24-02
KME

MOTION

April 24, 2002

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission adopt the Order in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

PJF/sdh

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Motion

by Public Service Commission

04/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

April 24, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schulz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On September 7, 2001, the North Dakota Public Service Commission advocacy staff (staff) filed a complaint against Montana-Dakota Utilities Co. (MDU), a division of MDU Resources Group, Inc., alleging that MDU's current rates result in excess revenue collections of $9.155 million per year. Also on September 7, 2001, staff filed its testimony in support of its complaint.

On September 19, 2001, the North Dakota Public Service Commission (Commission) found that staff's complaint states a *prima facie* case and served the complaint on MDU.

On November 5, 2001, Commissioner Susan Wefald wrote to the parties regarding the applicability of handling off-system sales revenue through the fuel

adjustment clause and asking whether the Commission should consider incentives to encourage future off-system sales. On November 21, 2001, staff replied, asserting that no change in existing policy should be made, thereby excluding off-system sales profits from the fuel adjustment clause. Staff also provided information regarding a number of incentive plans used by other state commissions to encourage the selling of off-system sales. On December 3, 2001, MDU replied stating that any discussions of this issue should focus on the need for incentives and a proper balance of the risks and rewards.

On November 13, 2001, MDU filed a letter confirming the procedural schedule agreed to orally by MDU and staff.

On November 21, 2001, the Commission issued a Notice of Hearing and Notice of Public Input Session. The notice set forth the following issues for consideration in the proceeding:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On December 11, 2001, the Commission conducted a Public Input Session via interactive videoconference, with hearing sites in Bismarck, Dickinson and Williston. The public input included concerns about escalating prices requiring the lowering of thermostats, a commendation for reliable service, questions concerning changes in company wide earnings and stock prices, concerns about the workability of investor owned utilities in conjunction with rural electric cooperatives and, general questions about deregulation and alternative forms of regulation. Staff and MDU responded to all questions.

On January 11, 2002, MDU's six witnesses filed direct testimony asserting that rates do not need to be changed.

On February 11, 2002, staff's two witnesses filed its rebuttal testimony reducing its initial complaint of excess earnings from $9.155 million to $7.327 million.

On February 19, 2002, MDU added four new witnesses and filed its surrebuttal testimony arguing that rates do not need to be changed.

On February 25 and 26, 2002, the Commission conducted a formal hearing as scheduled. No motions to intervene were filed. On March 5, 2002, MDU filed late-filed exhibits.

On March 5, 2002, MDU filed Late Filed Exhibit 16 providing monthly on-peak prices for MAPP for the period 1998 through 2001, Late Filed Exhibit 17 providing details of changes in office supply expenses from 2000 to 2001, Late Filed Exhibit 18 an updated summary of insurance expense for 2001 and projected 2002, Late Filed Exhibit 19 providing information on corporate aircraft expense, and Late Filed Exhibit 20 providing details of the change in administrative and general salaries between 2000 and 2001.

On April 10, 2002, MDU filed an update to Late Filed Exhibit 20 to include administrative and general salaries for 1999.

On April 16, 2002, MDU submitted an affidavit of Terry L. Blinsky, Electric Bulk Power Marketing Coordinator for MDU, containing first quarter 2002 wholesale sales and sales for resale margin. MDU requested that this information be made part of the record. MDU also requested that Case No. PU-399-01-186 be held open temporarily for the purposes of settlement negotiations which MDU had initiated with the Commission Staff.

On April 18, 2002, Commission staff filed a response to the affidavit of Terry L. Blinsky stating no objection generally to the filing of the information except to the relevance and subject of paragraph 5 of affidavit.

On April 22, 2002, Commission staff filed a letter stating that it could not reach a settlement agreement with MDU.

The Commission, having reviewed the evidence in the record makes the following:

Findings of Fact

1. MDU is an investor owned utility company operating as a division of MDU Resources Group, Inc. MDU provides retail electric service to approximately 70,000 customers in North Dakota.

2. Advocacy staff witness Mike Diller, Public Service Commission Director of Accounting, identified the primary components of rate of return regulation as rate base, cost of capital and net regulated income. He explained how the components are used to determine if MDU's rates should be adjusted and provided the Commission with worksheets for use in its deliberations.

3. Except for the specific exceptions noted below, the parties do not dispute the:

- 2002 test year for rate determination.
- Jurisdictional cost of service study.
- Test year rate base.
- Capital structure.
- Cost of preferred equity.
- Test year revenues (except for sales for resale margins).
- Test year expenses (except for administrative and general expenses).

Test Year Rate Base

4. Diller presented historical rate base amounts reported by MDU and 2002 test year rate base levels for this proceeding. MDU agreed to Diller's test year value for rate base. The commission finds the following historical rate base levels and 2002 test year rate base:

	(Thousands)			
	Reported by MDU			2002
Description	1999	2000	2001	Test Year
Plant in Service	$366,890	$375,347	$379,126	$381,289
Accum. Res. for Depreciation	193,286	202,071	215,094	215,130
Avg. Net Plant in Service	$173,604	$173,276	$164,032	$166,159
Constr. Work in Progress	2,572	850	518	518
Materials & Supplies	3,252	3,202	2,909	2,909
Fuel Stocks	1,192	1,277	1,255	1,255
Prepayments	265	209	99	107
Net Negative Salvage				
Accum. Def. Income Taxes	(42,124)	(41,564)	(39,774)	(39,807)
Accum. Invest. Tax Credits	(3,583)	(3,074)	(2,229)	(2,229)
Customer Advances	(309)	(509)	(10)	(10)
Average Rate Base	$134,869	$133,667	$126,800	$128,902

5. The parties dispute the following issues:

- The return on common equity.
- The overall cost of long-term debt.
- The appropriate level of sales for resale margins.
- The appropriate level of administrative and general expenses.

Return on Common Equity

6. The parties dispute the return on common equity (ROE) MDU should be allowed an opportunity to earn.

7. MDU's witness, Steven Gaske, asserted that a return on equity of 12.75% is a fair and reasonable return to MDU's stockholders using a Discounted Cash Flow (DCF) calculation.

8. Staff's witness, Charles King, asserted that a return on equity of 11.7% is a fair and reasonable return to MDU's stockholders using a DCF calculation.

9. During cross-examination, Gaske reviewed the annual survey of returns on equity granted by other state commissions as reported in the Public Utilities Reports for the year ended September 30, 2001. After reviewing the reports, Gaske noted that of the 45 companies listed, eleven companies were granted returns on equity higher than 11.7% and only three companies were granted returns on equity that were equal to or higher than 12.75%.

10. Two primary areas of disagreement, resulting in different recommended rates of return on common equity, include:

- Flotation costs.
- Comparable companies.

Flotation Costs

11. Flotation costs are the costs associated with issuing new common equity capital and make up approximately 58 basis points of difference between MDU's and staff's positions. Eliminating the flotation cost from Gaske's calculation reduces his recommended return on equity to 12.17%.

12. Staff's position included a review of floatation costs actually incurred during the past five years. King found that the actual costs were immaterial and lost in the rounding when applied to the return required on common equity. As a result, staff did not include any flotation costs in its return on equity calculation.

13. Rather than using actual expenditures, MDU witness Gaske included a theoretical cost of issuing common equity based on a sampling of electric companies during 1996-2000. Gaske assumed flotation costs of 4.75% for new equity which he incorporated in his proposed return on equity.

14. Under cross-examination, Gaske provided no empirical data to show that disallowing flotation costs would hinder the issuance of stock. On the contrary, Gaske agreed that most regulatory commissions do not allow flotation costs.

15. Given that staff has provided evidence based on historical information, we find no need to rely on the theoretical information provided by MDU. In addition, Gaske admitted that most regulatory commissions do not allow flotation costs. The evidence indicates a negligible amount of flotation costs in the instant case. Therefore, the Commission will not include flotation costs in the determination of return on common equity.

Comparable Companies

16. Staff witness King used a DCF analysis to estimate the cost of common equity. King testified that if the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit (comparable earnings test). For the comparable earnings test, King identified companies that have a bond rating of BBB or better from Standard & Poors and Baa or better from Moody's, companies of broadly comparable size, companies that have $100 million or more in gross revenue, and companies whose market risk is driven by the earnings from providing regulated utility services, including retail electric service. King identified eight combination gas-and-electric companies and four electric-only companies with at least 85 percent of revenue generated by regulated activities. King testified that the comparison companies should be comprised of eight combination gas-and-electric companies since MDU is a combination gas and electric utility company. King used a "interest rate risk premium" check to test his DCF conclusions for reasonableness.

17. MDU witness Gaske used 12 companies including both electric-only and combination (gas and electric) companies for his DCF analysis. The 12 companies used met Gaske's threshold of 75 percent of revenue from regulated retail revenue. Gaske asserts that because this proceeding is about MDU's electric operations, the comparison group should also include electric only companies. Gaske used a risk premium approach known as the Ibbotson & Singfield study and also the "alternative equity investment approach" to test his DCF conclusions for reasonableness.

18. Staff asserts that the comparison companies should be comprised of combination gas and electric companies because MDU is a combination gas and electric utility company. Gaske asserts that because this proceeding is about MDU's electric operations, the comparison group should also include electric only companies.

19. Montana-Dakota Utilities Co. is a division of Montana-Dakota Resources Group, Inc. As such, any common stock issuance or dividend paid is done so by Montana-Dakota Resources Group, Inc., a combination gas and electric company.

20. We find that the list of comparable companies should consist of companies with 85 percent or more of revenue from revenue generated by regulated activities. We find merit in MDU's assertion that electric-only companies should be used to determine the cost of equity capital that is devoted to providing regulated retail electric service in North Dakota. However, we find that MDU compromises this philosophy by including combination gas-and-electric companies in its calculation. We also find merit in staff's assertion that the list of comparable companies must consist of combination gas-and-electric companies since MDU is a combination company, however, the comparable companies should perhaps have the same relative proportions of electric-to-gas business as MDU.

21. We conclude that the list of comparable companies for this proceeding should consist of both electric-only and combination gas-and-electric companies with 85 percent or more of revenue from revenue generated by regulated activities. Accordingly, we find that a return on equity of 11.8% is a fair and reasonable return on equity to MDU's stockholders.

Weighted Cost of Long-Term Debt

22. The parties dispute the overall cost of long-term debt. MDU proposes a weighted cost of 9.22% whereas staff advocates a weighted cost of 8.62%.

23. Diller testified that MDU's reported cost of debt since 1988 remains significantly higher than the cost reported by the other two investor owned electric companies operating in North Dakota.

24. MDU witness Gaske testified that differences in the cost of debt are due to timing of financing needs and therefore are often explained by the vintage of the debt obligations.

25. Staff witness King testified an accounting-based cost of debt calculation. King recommended that debt issuance and redemption costs be amortized over the life of the debt issues, which results in MDU recovering all of its costs. Using an accounting-based cost, staff asserts that MDU's cost of debt is 8.62%.

26. MDU asserts a "yield-to-maturity" cost of debt calculation is more appropriate. Gaske testified that the yield to maturity calculation gives consideration to the time value of money..

27. We find the "yield-to-maturity" cost of debt calculation is more appropriate as it gives consideration to the time value of money.

28. The Commission finds that an overall weighted cost of capital of 10.24% for MDU is just and reasonable as follows:

	Cost of Capital		
Description	Capital Ratio	Cost	Weighted Cost
Long-Term Debt	45.90%	9.22%	4.23%
Preferred Stock	5.23%	4.63%	0.24%
Common Equity	48.87%	11.80%	5.77%
TOTAL	100.00%		10.24%

Sales for Resale Margins

29. The parties dispute the appropriate level of sales for resale margins. MDU proposes using 2001 sales levels combined with futures prices as of January 2002. Staff advocates using a 3-year historical average.

30. Staff testified that using an average of sales for resale margins during the past three years results in a normalized level of $11,695,641 on a total company basis. Diller's resale settlement calculation, offered at the hearing, shows that staff has reduced 2001 sales for resale margins by $2.8 million on a North Dakota basis for the 2002 test year.

31. The staff method of normalizing sales for resale margins is based on actual transactions that have occurred during the past 3 years and then averaged to result in a proxy for expected margins in the future.

32. MDU proposed using 2001 sales volumes and splitting the sales into off-peak and on-peak sales. The margins were then calculated by multiplying the off-peak sales by an estimated price and the on-peak sales by futures prices quoted by the NYMEX Cinergy Hub.

33. Diller identified 28 factors affecting future resale margins from the testimony of MDU's ten witnesses. One of the factors listed by Diller includes "new generation capacity." If price is determined by supply and demand principles discussed in this case, new electric supplies to meet new demand are critical to the long-term pricing of electricity. According to MDU's representation, the Mid-American Power Pool (MAPP) forecasts excess capacity in the future. However, Exhibit 11 entered by Commissioner Wefald shows that the North American Electric Reliability Council suggests that the MAPP capacity is inadequate for the time period of 2001-2010. This indicates that the experts can't agree on the critical element of the supply side of the price equation.

34. With respect to the demand side of the price equation, staff asserts that determining sales for resale margins based primarily on futures prices of the day is unreasonable.

35. MDU splits its margins calculation between off-peak and on-peak sales. Diller questioned the calculation in his rebuttal testimony because the off-peak sales margins portion reflects a net loss contribution to earnings of $144,319. Blinsky testified that it is not MDU's common practice to sell below the incremental cost of fuel. Blinsky further asserted that his calculation uses average fuel costs and that during off-peak periods the off-system sales typically come from a specific unit.

36. Diller stated in his rebuttal testimony that staff requested source data for Blinsky's off-peak prices. According to Diller's testimony, MDU replied that the off-peak prices are estimates based on recent experience. Diller continued in his rebuttal testimony that without the source data and some historical perspective, staff is unable to conclude anything from MDU's sales for resale margins calculation.

37. MDU calculated on-peak margins by multiplying 2001 sales volumes by the futures prices listed by NYMEX on a particular day. Diller testified that futures are going be less likely to predict actual electricity prices the further out you go. Gaske testified that the futures prices are the best estimate of what electricity will cost in the future and that the futures prices consider all the factors that affect the price of electricity.

38. In its April 16, 2002 filing, MDU witness Blinsky states that the level of wholesale sales for the period January 1, 2002 through March 31, 2002 was 226,353 Mwh as compared to 260,830 Mwh sold in the first quarter of 2001. Blinsky further states that the level of sales for resale margins for the period January 1, 2002 through March 31, 2002 was $1,618,840 as compared to the $4,126,072 sales for resale margin for the first quarter of 2001.

39. Staff has shown, based on historical evidence, that MDU has made significant margins in its sales for resale. MDU has attempted to predict reduced sales for resale margins through estimates of future sales and future prices.

40. The Commission finds a high degree of uncertainty associated with predictions that are affected by one or more of at least 28 factors and the large number of combinations of those factors that are outside MDU or Commission control. These factors can change dramatically as evidenced by the change in prices of natural gas in recent years. We find that using the average of sales for resale during 1999, 2000, and 2001 is the most appropriate decision at this time.

Administrative and General Expenses

41. The parties dispute the appropriate level of administrative and general expenses. MDU proposes a 12.3% increase compared to 2001 levels. Staff proposes a 4.6% reduction compared to 2001 levels.

42. The administrative and general (A&G) expense category includes a number of accounts including salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, regulatory Commission expenses, general advertising, miscellaneous general, rents and the maintenance of general plant.

43. Staff presented evidence at the hearing that MDU's A&G expenses had been declining since 1996 until the year ended 2000. MDU reported a 12.4% increase in A&G expenses in 2001 and MDU now asserts that a 12.3% increase for 2002 is justified.

44. Staff asserted that MDU's testimony does not provide an analytical approach to quantifying future estimated costs and therefore the A&G expense increase sponsored by MDU should be rejected.

45. Four general areas of concern were identified with respect to A&G expenses including MDU's projection of A&G salaries, office supplies expense, insurance expense and pensions and benefits.

A&G Salaries

46. Staff noted a significant increase in the salaries account of A&G expenses from 2000 to 2001. Staff did not originally take exception to the expense level because staff assumed that the difference was due to different levels of salary capitalization from one year to the next. Under cross-examination, MDU witness Ball was not sure why A&G salaries increased so much but thought it had to do with the capitalization differences as well. Through cross-examination, Ball agreed to research the difference and file Late Filed Exhibit No. 20. Late Filed Exhibit No. 20 discloses that a significant portion of the difference resulted from the payment of higher bonuses and commissions. The bonuses and commissions are $635,765 higher on a total electric company basis, more than double the year 2000 level. At the request of the Commission, MDU updated Late Filed Exhibit 20 to include 1999 data.

47. We find that 2001 A&G salaries expense level is significantly higher than previous years because the bonuses and commissions component of A&G salaries is significantly higher. We find that this level of bonuses and commission is unreasonable and should not be included in the 2002 test year. Therefore we find that an appropriate level of bonuses and commissions for the 2002 test year is an average of that expense for years 1999, 2000, and 2001.

Office Supplies Expense

48. The office supplies expense category includes such expenditures as automobile services, bank charges, books and subscriptions, building service, communications, office equipment, computer infrastructure, membership fees, office supplies, legal department expenses, postage and printing, travel and incidental expenses and corporate aircraft expenses.

49. Diller provided an exhibit showing office supplies expense for the years 1996 through 2001. Diller testified that normal office supplies expense is approximately $1.8 million to $2.1 million annually, but that actual expenditures for 2001 were reported to be $2.9 million. Staff proposed adding 5% to actual 2000 expenses, resulting in a 2002 test year level of $2.228 million.

50. MDU asserted that its reported level of office supplies expense in 2001 is a reasonable expense level for 2002.

51. Staff's position is that the expenditures included in office supplies expense are controllable. Staff testified that it is unreasonable to assume that one extremely high cost year is representative of future expense levels.

52. Staff asserted that MDU did not use an analytical approach to quantifying future estimated costs. Instead, MDU relied on the expenditure level of one high cost year (2001). Staff highlighted its concerns by pointing out that MDU attributes a substantial part of the increase to its new corporate aircraft and that MDU did not quantify the savings attributable to acquiring the aircraft.

53. The Commission agrees that office supply expenses are controllable by MDU. We find that 2001 office supply expense level is significantly higher than previous years and there is no evidence that the significantly higher year is representative of a reasonable test year expense level. The Commission finds that an fair and reasonable level of office supply expenses for the 2002 test year is an average of the office supply expenses for years 1999, 2000, and 2001.

Insurance Expense

54. MDU proposes an increase in North Dakota insurance expense of $155,383 to reflect higher 2002 premiums. MDU testified that the events on September 11, 2001, resulted in increased insurance costs and that the higher costs are reflected in the 2002 premiums.

55. Staff asserts that MDU's testimony did not include a review of all insurance expenditures and that MDU's evidence is inconclusive.

56. MDU Late Filed Exhibit 18 identifies the premiums that are expected to cause year 2002 increases.

57. The Commission finds that MDU's projected insurance expenses are reasonable for the 2002 test year.

Pensions & Benefits

58. Staff identified two areas of concern regarding MDU's proposed cost of pensions and benefits, as follows:

- Pension Expense and Post Retirement Expense (FAS 106)
- Supplemental Income Security Plan (SISP)

Pension and Post Retirement Expense

59. MDU witness Ball proposes an adjustment to pension expense and post retirement expense. Staff testified that it asked for source data related to the adjustments but the actuarial information was not provided. MDU offered to let Diller review the actuarial study on a confidential basis.

60. Diller concluded that both the pension expense and post retirement expense adjustments proposed by MDU do not include a review of all employee pension and benefits expenditures and are therefore inconclusive. Staff proposed using 2001 expense levels as a reasonable level for the 2002 test year.

61. Ball testified that MDU has no knowledge of known changes to pension and post retirement expenses other than the 2002 actuarial studies. Ball asserted that the increase is attributable to low investment returns in recent years and the use of a lower discount rate for future years. He further testified that the increases for 2002 are real and currently being booked and that more increases are expected through 2005. MDU's case includes an upward adjustment to 2001 expense of $179,000 for pension expense and $62,000 for post retirement expenses.

62. Staff did not further dispute the increases for 2002 related to pension and post retirement expenses or whether said expenses are real and are currently being booked.

63. The Commission finds that the upward adjustment to 2001 expense of $179,000 for pension expense and $62,000 for post retirement expenses is reasonable for the 2002 test year.

Supplemental Security Income Plan (SISP)

64. MDU proposed to include expenses associated with SISP. MDU witness Richard Espeland testified that SISP is a supplemental pension benefit that is necessary to

attract, retain and provide equitable benefits for key employees. MDU asserts that various changes in federal regulations, Social security benefits, and employment practices have adversely affected MDU key employees. MDU points out that defined benefit pension plans, that in the past could include benefits in consideration of up to $225,000 of salary, have been limited to $200,000. 401(k) plan regulations limit employee contributions limiting the percentage of income a key employee can contribute as compared to a lower salaried employee. MDU also testified that the Social security covered wage base has not kept pace with the general wage inflation and benefits provided at higher income levels are significantly less than at lower income levels. In general, MDU asserts that the more traditional plans benefit the low paid employees more than the high paid employees on a percentage of income basis and SISP enables MDU's key employees to benefit on a more comparable basis when considering benefits as a percentage of income.

65. Diller characterized SISP as a double pension for MDU's few key employees and compared it to the Enron debacle and the payments Enron made to key employees. Diller noted that one of the Congressmen in the recent Enron hearings stated that payments to key employees looked like management taking care of itself. Diller observed that Enron provided a warning to all of us, especially to managers of companies.

66. Staff objects to including SISP in ratemaking expense. Diller testified that while the plan has been in effect since 1982, the company has never sought rate recovery in any subsequent electric or gas rate case. Staff opposes spending a million dollars a year for the benefit of a few employees. In addition to SISP, employees that are allowed to participate in SISP are paid very well (minimum of $75,000 to $80,000 per year) and participate in all the other benefits offered to regular employees such as health insurance, life insurance, 401k participation, profit sharing plans, incentive plans, defined benefit plans, social security and discounted gas and electric service for those living in MDU's service territory.

67. Diller testified that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. For instance, an employee making $50,000 a year would receive a monthly SISP benefit of $1,330 compared to a monthly benefit of $30,000 for the employee making $600,000 a year. In the case of the low-end employee, the monthly benefit calculates to be 2.66% of annual salary compared to the high-end employee who would receive a monthly benefit of 5% of annual salary. Diller noted that only 27 employees of MDU's gas and electric employees are considered to be key employees.

68. The Commission concludes it is inappropriate for ratepayers to bear this expense. The Commission finds that SISP expenses should not be included in ratemaking expense.

Earnings

69. The Commission finds the following historical summary of reported revenue and expenses, and the reasonable test year revenue and expenses, as follows:

	(Thousands)				
	Reported by MDU				
Description	1999	2000	2001	Adjustments	Test Year
Sales for Resale	$13,265	$15,034	$17,687	($2,800)	$14,887
All Other Revenues	80,657	81,929	84,415	0	84,415
Total Revenues	$93,922	$96,963	$102,102	($2,800)	$99,302
Production Expense	$37,160	$38,365	$40,671	($765)	$39,906
Transmission Expense	3,667	3,567	3,915	370	4,285
Distribution Expense	4,586	4,660	5,010	0	5,010
Customer Accounts	2,162	2,113	2,233	0	2,233
Customer Service & Info.	96	105	113	0	113
Sales Expense	258	269	281	0	281
Administration & General	8,303	8,154	8,968	(205)	8,763
Total O & M Expense	$56,232	$57,233	$61,191	($600)	$60,591
Depreciation	$11,436	$11,803	$11,955	$77	$12,032
Taxes Other Than Income	$3,936	$3,811	$4,019	$0	$4,019
Income Tax Expense	$6,319	$6,750	$7,955	($1,075)	$6,879
Net Regulated Income	$15,999	$17,366	$16,982	($1,201)	$15,781
Income Tax Calculation:					
Net Income Before Taxes	$22,318	$24,116	$24,937		$22,660
Less Interest Deduction:					
Rate Base	$134,869	$133,667	$126,800		$128,902
Weighted Cost of Debt	4.93%	4.74%	3.96%		4.23%
Calculated Interest Deduction	$6,644	$6,332	$5,017		$5,456
Other Tax Adjustments	$281	($743)	$163		$163
Taxable Income	$15,955	$17,041	$20,083		$17,368
Combined Tax Rate	39.61%	39.61%	39.61%		39.61%
Income Tax Expense	$6,319	$6,750	$7,955		$6,879

70. The Commission finds MDU's 2002 test year excess revenue of $4,273,000, as follows:

Description	(Thousands) Test Year
Average Rate Base	$128,902
ROR Required (11.8% ROE)	10.24%
Return Required	$13,201
Return Earned	$15,781
Return (Excess)	($2,580)
Tax Factor	1.656
Revenue (Excess)	($4,273)

From the foregoing Findings of Fact, the Commission makes its:

Conclusions of Law

1. The Commission has jurisdiction over the parties in and the subject matter of this proceeding.

2. MDU is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.

3. MDU's existing electric rates yield excess revenues of $4.273 million per year.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU shall implement an across the board rate reduction sufficient to produce a total annual rate revenue decrease of $4.273 million. MDU shall file revised tariff sheets reflecting the rate reduction to be effective for electric service rendered on and after May 8, 2002.

2. The April 16, 2002, request by MDU that the affidavit of Terry L. Blinsky be made part of the record in this proceeding is granted.

PUBLIC SERVICE COMMISSION

Anthony T. Clark	**Susan E. Wefald**	**Leo M. Reinbold**
Commissioner	**President**	**Commissioner**

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc 2000 Electric Operations Annual Report

Case No. PU-399-01-186

Concurring Opinion
Commissioner Susan E. Wefald

April 24, 2002

This case is a result of a staff investigation into Montana Dakota Utilities (MDU) electric utility rates due to the high earnings that MDU is experiencing in its electric operations. This order will provide opportunities for MDU to achieve 11.8% return on equity, and the 5.06% rate reduction is fair to customers of MDU.

In this case the Commission examined both the income and expenses of MDU electric operations. The rate reduction in this case is a result of determining a reasonable level of income and expenses.

Over the past several years, MDU has sold large amounts of electricity to other utilities. These sales to other utilities have provided MDU with increased profits in the past few years. MDU argued in this case that in the future they will not have as much income from off system sales as they have had in the past few years. There is a lot of uncertainly with making predictions regarding future revenues and future sales.

The Commission also took a close look at the Administrative and General Expenses of MDU and decreased expenses in that area by $205,000. The Commission allowed increases in some subareas that were justified (such as insurance costs that have risen since September 11, 2001) but did not allow expenses (for example, the Supplemental Security Income Plan) and reduced expenses in other areas (such as Office Supply Expenses).

Susan Wefald

Commissioner Susan E. Wefald

100 PU-399-01-186 Pages: 1

Concurring Opinion by Commissioner Wefald
by Public Service Commission

04/24/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

Concurring Opinion
Commissioner Anthony T. Clark

April 24, 2002

There were a number of issues to decide in this case in order to get to the bottom line, but the biggest ticket item in dispute was how to handle the large profits reaped by MDU from the sale of excess power to other markets. To address this, the two sides presented essentially two different regulatory paradigms.

MDU asks the Commission to keep rates the same, ignoring the historic profit levels they have made for a number of years. Instead, they ask the Commission to base rates on a futures market that their witnesses said indicated lower profits from excess sales.

Staff asked the Commission to base its decision on historic rates and profits. By using the historic numbers, in this case a three-year average of MDU profits from sales, staff justifies a cut in rates.

I find more merit in staff's argument. It relies on the one sure thing we do know, actual profits and experience in the marketplace. Unfortunately, the futures market has proven to be a less than reliable predictor of what actually occurs at any given time. MDU witnesses even testified to this fact.

MDU witnesses were in the difficult position of making two contradictory arguments. They indicated that no one could have predicted the markets that have given MDU the ability to earn excess profits in recent years. At the same time, MDU asks the Commission to predict future markets with absolute clarity. This is an untenable position.

We simply cannot predict with certainty where prices will go in the next few years. What will happen with transmission constraints? Will Congress permit Yucca Mountain to be the nuclear waste repository? Will the weather be cold or warm in the next few years? Will new government policies encourage or discourage the production of energy? What will happen with the economy? Will future environmental regulations

help one particular fuel source over another? To accurately predict the future price of wholesale electricity, we would have to know the answers to all these questions plus many, many more.

Out of the two models advocated and made part of the record, I find the staff approach more reasonable. It depends on the most accurate, current data available. Additionally, staff made the test year even more fair by averaging the past three years profits, so as to mitigate any one year anomalies.

Might excess power pool sales dry up for MDU? Yes, they might. In which case, MDU might return to the Commission and ask for an increase at some future date.

Might MDU make even more excess power pool sales in the next few years? Yes, that might happen too. In that case, staff will likely file for another rate reduction at some point.

Might excess power sales simply be volatile? That's certainly a possibility as well. In which case ratepayers and shareholders may alternately benefit for short periods of time.

Rates are always subject to change. The job of utility commissions is to be fair and reasonable to both consumers and regulated industries. In this case, based on the record, I believe we have clearly done that.

Anthony T. Clark, Commissioner

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

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ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

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TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

April 22, 2002

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co.
Case No. PU-399-01-186

Jon:

I am writing to inform you that the advocacy staff could not reach a settlement agreement with MDU in the above referenced case.

Sincerely,

William W. Binek
Counsel for Advocacy Staff

cc: William Pearce
Don Ball

98 **PU-399-01-186** Pages: 1

Letter notifying Commission of termination of settlement negotiations by Public Service Commission by Wm. Binek

04/22/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

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Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

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April 18, 2002

Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard Avenue, Dept. 408
Bismarck, ND 58505

Re: Montana-Dakota Utilities Co., Electric Rates Investigation, PU-399-01-186

Dear Mr. Mielke:

The Commission Advocacy Staff has reviewed the Affidavit of Terry L. Blinsky dated April 16, 2002, regarding the actual level of wholesale sales for the first quarter of 2002. Staff has no objection generally to the filing of this information, but Staff believes the information adds nothing to the case.

Staff does, however, question the relevance of paragraph 5 where the projected level of sales for resale margins for 2002, based on a simple annualization of actual first quarter results, is compared to MDU's margin estimate testified to at the hearing. The comparison suggested by MDU requires an assumption that the actual results of the first quarter will be replicated in the next three quarters of 2002. There is no basis for such an assumption, and therefore Staff objects to paragraph 5 of the Affidavit.

Sincerely,

William W. Binek
Counsel for Advocacy Staff

cc: William P. Pearce

97 **PU-399-01-186** Pages: 1

Commission Advocacy Staff's response to
Terry L Blinsky's Affidavit
by Public Service Commission

04/18/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

PEARCE & DURICK

WILLIAM R PEARCE 1910-1978
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OF COUNSEL
HARRY J. PEARCE

April 16, 2002

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APR 16 2002
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard Avenue
Bismarck, ND 58505

Re: PU-399-01-186
Montana-Dakota Utilities Co.

Dear Mr. Mielke:

The principal issue in the captioned case is the probable amount of resale sales margins which Montana-Dakota Utilities Co. can reasonably expect to achieve during the year 2002.

At the hearing on February 15-26, 2002, the most recent actual results available on resale margins extended through the first half of February 2002. The Company now has actual data through March 31, 2002, the end of the first quarter. Accordingly, I am submitting on behalf of Montana-Dakota Utilities Co. the enclosed affidavit of Terry L. Blinsky containing this updated information, and request that it be made a part of the record in this matter, pursuant to N.D.C.C. § 28-32-25. Mr. Blinsky can be made available for sworn testimony concerning this matter, should the Commission wish.

I would also request that this matter be held open temporarily for the purposes of settlement negotiations which the Company has initiated with the Commission Staff in this case. We have discussed this with the Commission Staff and are authorized to state that the Staff is willing to discuss settlement of the matter.

Very truly yours,

William P. Pearce

WPP:pr
Enc.

96 PU-399-01-186 Pages: 1

Request for case to be held open for purposes of settlement negotiations by Montana-Dakota Utilities Co., a Division of MDU Re

04/16/2002 CC: Comm Legal Illona, Pat, Jerry Mike

• ALSO LICENSED IN MINNESOTA • ALSO LICENSED IN

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Electric Rates Investigation

Case No. PU-399-01-186

Affidavit of Terry L. Blinsky

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

Terry L. Blinsky, of lawful age, being first duly sworn on his oath, deposes and says:

1. That he is the Electric Bulk Power Marketing Coordinator for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. and in that capacity he is directly involved with and familiar with all aspects of Montana-Dakota's wholesale sales of electric power, including the Mwh levels of all such sales as are made from to time and the revenues received from such sales and the resulting profits attained by Montana-Dakota from such sales ("sales for resale margins").

2. That in the hearing held in this matter on February 25-26, 2002, he testified regarding the projected level of sales for resale margins for 2002 and the actual level of sales for resale margins made by Montana-Dakota during January 2002 and the projected level of such sales for February 2002, based on doubling the actual levels for the first half of February.

95 PU-399-01-186 Pages: 2
Affidavit of Tery L Blinsky
by Montana-Dakota Utilities Co., a Division of MDU Re
04/16/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

3. That the actual level of wholesale sales for the period January 1, 2002 through March 31, 2002 was 226,353 Mwh which compares favorably with the 260,830 Mwh sold in the first quarter of 2001.

4. That the actual level of sales for resale margins for the period January 1, 2002 through March 31, 2002 was $1,618, 840, which is substantially less than the $4,126,072 sales for resale margin achieved in the first quarter of 2001.

5. That, accordingly, the projected level of sales for resale margins for the entire year 2002, based on a simple annualization of the actual first quarter results is $6,475,360 which compares favorably with the 2002 margin estimate of $6,429,778 testified to at the hearing (Exhibit No. ___(TLB-5).

Dated April 16, 2002.

Terry L. Blinsky

Terry L. Blinsky

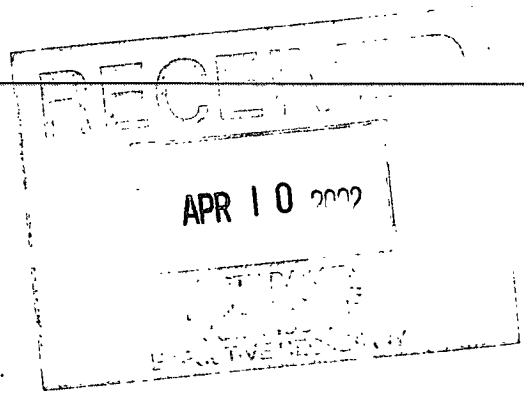
Subscribed and sworn to before me this 16th day of April, 2002.

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

Steve Reed

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

Fahn, Patrick J.



From: Mulkern, Rita [MulkernR@MDU.MDURES.com]
Sent: Wednesday, April 10, 2002 8:42 AM
To: 'Fahn, Patrick J.'
Cc: Ball, Don
Subject: RE: request for additional information

Attached is the information you requested on A&G salaries for 1999.

-----Original Message-----
From: Fahn, Patrick J. [mailto:pjf@oracle.psc.state.nd.us]
Sent: Tuesday, April 09, 2002 11:07 AM
To: MDU-Rita Mulkern (E-mail)
Cc: Comm; Mielke, Jon H.; Legal; PUD
Subject: request for additional information

At it's April 9, 2002, worksession for Case No. PU-399-01-186, the Commission requested that MDU provide additional information concerning Late Filed Exhibit No. 20: "Summary of A&G Salaries". In addition to the Account 920 dollar amounts already provided on that exhibit for years 2000 and 2001, please provide dollar amounts for year 1999.

We understand this information is readily available, therefore, please provide the information by the end Wednesday, April 10, 2002. The next worksession in this proceeding is scheduled for 9am Thursday, April 11, 2002.

Patrick J. Fahn

Chief Engineer, Public Utilities Division

600 East Boulevard

Bismarck ND 58505-0480

701-328-4077

701-328-2410 (fax)

pjf@oracle.psc.state.nd.us

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF A&G SALARIES
ELECTRIC UTILITY

		Account 920		
		2001	2000	1999
5110	Straight Time	$3,411,907	$3,127,054	$3,076,375
5120	Premium	25,743	27,179	27,813
5130	Bonus & commission	1,217,274	581,509	546,840
5140	Moving	5,715	226	4,849
5150	Meals	624	551	567
5193	Vacation	362,936	444,800	461,185
	Total	$5,024,199	$4,181,319	$4,117,629

Public Service Commission
State of North Dakota

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COMMISSIONERS

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April 4, 2002

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505

RE: PU-399-01-186
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Mielke:

Enclosed is the original and seven copies of Staff Response to Brief of Montana-Dakota Utilities Co.

Sincerely,

William W. Binek
Chief Counsel

wwb/sls

Enclosure

c: Don Ball, MDU
William Pearce

93 **PU-399-01-186** Pages: 1

Cover letter re Staff Response to Brief of MDU
by Public Service Commission by Wm. Binek

04/04/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

STAFF RESPONSE TO BRIEF OF MONTANA-DAKOTA UTILITIES CO.

At the conclusion of the hearing in this proceeding, the Public Service Commission (Commission) requested that both Montana-Dakota Utilities Co. (MDU) and the Public Service Commission Advocacy Staff (Staff) submit proposed Findings of Fact, Conclusions of Law and Order for the Commission's consideration. No request was made for the filing of briefs.

On April 2, 2002, both the Staff and MDU filed proposed Findings of Fact, Conclusions of Law and Order, but in addition, MDU filed a brief in support of its position. Consequently, Staff is compelled to file a short response to MDU's brief.

Staff does not disagree with MDU's arguments concerning the law that is applicable in this case. Staff does disagree with MDU's assertions as to the evidence or lack of evidence presented by Staff.

Wholesale Electric Sales Margins

MDU asserts that Staff presented no evidence to support its position concerning wholesale electric sales margins. That assertion by MDU is erroneous. Staff proposed that the Commission use a three-year average of **actual** sales for resale to establish the level of resale margins. Staff's rebuttal Exhibit MRD-1 depicts sales margins that have

been growing for the past six years. MDU, on the other hand, basically argues that the Commission should rely on the futures market to **project** future resale margins.

Staff presented evidence of **actual** sales that have been made over the past several years to support its position. MDU used future estimates and projections to support its position. In addition, Staff identified 28 factors affecting future resale margins from the testimony of MDU's ten witnesses. One of the factors listed by Staff includes "new generation capacity." If price is determined by supply and demand principles discussed in this case, new electric supplies to meet new demand are critical to the long-term pricing of electricity. According to MDU's representation, the Mid-American Power Pool (MAPP) forecasts excess capacity in the future. However, Exhibit 11 entered in the record shows that the North American Electric Reliability Council suggests that the MAPP capacity is inadequate for the time period of 2001-2010. This evidence contradicts the evidence submitted by MDU concerning the opportunities for resale sales in the future.

Both Staff and MDU pointed out numerous factors that may affect the future price of electricity. One of the most important factors is the price of natural gas. A natural gas issue of considerable importance is the effect of decreased drilling activity on the supply and price of natural gas. One or more of MDU's expert witnesses acknowledged that there currently is a decline in drilling activity, that most new electric generating capacity that has come on line or is being constructed is fueled by natural gas, and that the increased demand for natural gas means an upward pressure on natural gas prices.

Staff agrees that futures prices is one of the tools that may be used to estimate the future cost of electricity, but it is only one of several tools that may and should be employed by the Commission in rendering an overall decision in this case.

Cost of Capital

Staff argued that the weighted cost of capital should be 9.92%, and that the return on common equity should be set at 11.7%. Staff also recommends that the overall cost of long-term debt should be 8.62%. MDU argued that the weighted cost of capital should be 10.7%, and that the return on common equity should be set at 12.75%. MDU's proposed overall cost of long-term debt is 9.22%.

MDU acknowledged that in Public Utilities Reports annual survey of returns on equity granted by state agencies over the most recent one year period reported, out of 45 companies listed, only three companies were granted returns on equity that were equal to or higher than MDU's proposed 12.75%, and only 11 out of the 45 companies were granted returns on equity that were higher than the Staff's proposed 11.7%.

Long Term Debt

Staff argued that MDU's reported cost of debt since 1988 remains significantly higher than the cost reported by the other two investor owned electric companies operating in North Dakota, and that little progress has been made by MDU to bring its costs down to a level competitive with the other investor owned electric companies operating in North Dakota. MDU argued that differences in the cost of debt are due to timing of financing needs and therefore are often explained by the vintage of the debt obligations.

Staff argued for an accounting-based cost of debt. Staff recommended that debt issuance and redemption costs be amortized over the life of the debt issues, which results in MDU recovering all of its costs. Staff noted that the Commission utilized an accounting-based cost of debt calculation in Northern States Power Company's last rate case application. Using an accounting-based cost, Staff argued that MDU's cost of debt is 8.62%.

MDU argued for a "yield-to-maturity" cost of debt calculation. MDU's position is that the yield to maturity calculation gives consideration to the time value of money. Accordingly, the yield to maturity calculation results in a higher cost of debt or 9.22%.

The time value of money was not considered with respect to other expenses included in the test year. Staff testified that cash working capital is a calculated level of cash needed to pay ongoing expenses and that because revenues are often collected in advance of expenses, it can be a source of cost free capital. Staff testified that the Commission's practice with MDU has been to disallow cash working capital absent a lead-lag study. Staff pointed out that past Commission decisions have resulted in reducing rate bases of Otter Tail Power Company and Northern States Power Company for cash working capital and that its inclusion typically has benefited North Dakota ratepayers in other cases. Staff's position is that absent a lead-lag study, it is unwarranted and unfair to include the time value of money for debt issuance and redemption costs.

MDU's cost of debt remains significantly higher than the other investor owned utilities operating in North Dakota despite Staff's reduction of the $40 million four day loan that had been carried on MDU's books.

Comparable Companies

Staff used a DCF analysis to estimate the cost of common equity. Staff identified eight comparable combination (gas and electric) utility companies' dividends and growth estimates for estimating the return required on MDU's common equity. Staff used an "interest rate risk premium" check to test DCF conclusions for reasonableness.

. Using a different set of criteria, MDU utilized twelve companies including both electric only and combination companies for its DCF analysis. The different criteria resulted in MDU discarding four combination companies identified by Staff and adding others. MDU used a risk premium approach known as the Ibbotson & Singfield study and also the "alternative equity investment approach" to test its DCF conclusions for reasonableness.

Staff argued that the comparison companies should be comprised of combination gas and electric companies because MDU is a combination gas and electric utility company. Montana-Dakota Utilities Co. is a division of Montana-Dakota Resources Group, Inc. As such, any common stock issuance or dividend paid is done so by Montana-Dakota Resources Group, Inc., a combination gas and electric company.

Flotation Costs

Flotation costs are the costs associated with issuing new common equity capital. Staff argued that flotation costs should be excluded. MDU argued that the stock price must be sufficiently above book value so that stock can be issued without diluting the value of existing shareholders' investments.

Staff conducted a review of flotation costs actually incurred during the past five years. Staff found that the actual costs were immaterial and lost in the rounding when

applied to the return required on common equity. As a result, Staff did not include any flotation costs in its return on equity calculation.

MDU did not use actual expenditures in making its calculations. Instead, MDU argued for the inclusion of a theoretical cost of issuing common equity based on a sampling of electric companies during 1996-2000. MDU's theoretical flotation cost of 4.75% for new equity is then used to inflate the estimated return on equity. Staff believes that MDU's position includes enough flotation costs that MDU could reissue all of its common equity annually at the expense of ratepayers. MDU agreed that most regulatory commissions do not allow flotation costs.

Operating Expenses

MDU's brief discusses two issues under the Operating Expense category. Those issues relate to the Supplemental Income Security Program (SISP) and Office Supplies Expense. Staff includes in this brief a discussion of salaries.

Supplemental Income Security Program

MDU argued for the inclusion of expenses associated with SISP. MDU argued that the plan provides a supplemental pension benefit to key employees. MDU further argued that the benefit is necessary to attract and retain high quality Staff in a number of key positions within the company.

Staff argued strenuously against the inclusion of SISP in ratemaking expense. Staff argued that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. Staff noted that only 27 employees of MDU's gas and electric employees are considered to be key employees. Staff characterized SISP as a double pension for

MDU's few key employees and referenced the Enron debacle regarding the payments it made to key employees. Staff observed that one of the Congressmen in the Enron hearings stated that the payments to key employees looked like management taking care of itself.

Staff opposed spending a million dollars a year ($683,000 North Dakota share) for the benefit of a few employees. In addition to SISP, these key employees are paid a minimum of $75,000 to $80,000 per year according to MDU and participate in all the other benefits offered to regular employees such as health insurance, life insurance, 401k participation, profit sharing plans, incentive plans, defined benefit plans, social security and discounted gas and electric service for those living in MDU's service territory.

Staff stated and MDU agreed that while the plan has been in effect since 1982, the company has never sought rate recovery in any electric or gas rate case until now.

Office Supplies Expense

Staff's position is that the types of expenditures included in office supplies expense are controllable expenditures. Staff contended that with regard to these types of expenditures, MDU is not all that different from the Commission. Staff stated, for example, that there are some years when the Commission spends a lot of money on computer software and hardware upgrades, but there are also years when that is not the case because of budgetary constraints. Staff argued that it is unreasonable to assume that one extremely high cost year is representative of future expense levels. Staff's position is that controllable costs can be controlled and the Commission should order a reasonable and normal level of office supplies expense.

MDU's position is that the 2001 increase resulted from expenditures that will be continuing on a year-to-year basis rather than one-time increases. Staff supported a 5% increase from actual year 2000 expenses as being a reasonable office expense level. Staff pointed out that annual office supplies expense normally runs from $1.8 million to $2.1, but actual expenditures for 2001 were reported at $2.9 million.

Salaries

Staff noted a significant increase in the salaries account of A&G expenses. Staff pointed out that no exception was taken to the expense level as Staff assumed that the difference was due to different levels of salary capitalization from one year to the next. Under cross-examination, MDU witness, Donald Ball, was not sure why A&G salaries increased so much but thought it had to due with the capitalization differences as well. MDU agreed to research the difference and file Late Filed Exhibit No. 19. Late Filed Exhibit No. 19 discloses that most of the difference resulted from the payment of higher bonuses and commissions ($635,765 on a total electric company basis). Staff did not make an adjustment to salaries expense at the hearing, as this information was not known until after the hearing. However, the Late Filed Exhibit No. 19 is in the record as evidence in the case and should be considered by the Commission in making its decision. Staff believes that the bonus and commission increase from $581,509 to $1,217,274 is unwarranted and unreasonable.

Conclusion

One of the major issues in this case relates to wholesale electric sales margins. Staff presented evidence of actual sales that have occurred over the past several years to support its position that MDU's rates should be reduced. Staff recognized that

changes in the economy may impact future sales, and for that reason recommended that the Commission use a three-year average of actual sales to establish the level of resale margins. MDU proposes that the Commission rely the futures market to project future resale margins. Staff's evidence in the case is based on **actual** sales whereas MDU's evidence is based on **assumptions** and **projections.**

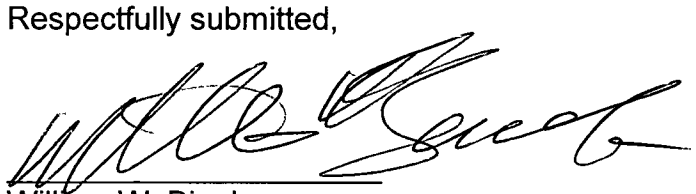
Another major issue is cost of capital. MDU's proposed return on common equity is 12.75%. MDU acknowledged that in Public Utilities Reports annual survey of returns on equity granted by state agencies over the most recent one year period reported, out of 45 companies listed, only three companies were granted returns on equity that were equal to or higher than MDU's proposed 12.75%, and only 11 out of the 45 companies were granted returns on equity that were higher than the Staff's proposed 11.7%. MDU's long-term debt is excessive when compared to other investor owned utilities operating in North Dakota. Flotation costs are unnecessary and should be disallowed.

The operating expenses should be reduced as recommended by Staff. The Supplemental Income Security Plan is a supplemental benefit available to only a few of MDU's highly paid employees. This is a costly plan ($683,000 North Dakota share) that has been in place since 1982, and until now has been paid for by MDU's shareholders. If MDU wants to continue this plan, it should continue to be paid for by the shareholders. The burden of paying for SISP benefits should not be shifted to MDU's ratepayers. The salaries expense item should also be reduced as a result of the disclosure in MDU's Late Filed Exhibit No. 19 which shows that most of the increase in salaries expense was a result of total company bonus and commission increase from $581,509 to $1,217,274. This increase is unwarranted and unreasonable.

Staff's position is supported by evidence and reason. The Commission should reduce MDU's rates in accordance with Staff's recommendations.

Dated April 4, 2002.

Respectfully submitted,



William W. Binek
Chief Counsel
Public Service Commission
600 E. Boulevard Ave. Dept. 408
Bismarck, ND 58505

Attorney for Advocacy Staff

PEARCE & DURICK

WILLIAM R PEARCE 1910-1978
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PATRICK W. DURICK
B. TIMOTHY DURICK
GARY R. THUNE •
DAVID E. REICH
JEROME C. KETTLESON
LARRY L. BOSCHEE •
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E-MAIL: law.office@pearce-durick.com

OF COUNSEL
HARRY J. PEARCE

APR - 2 2002
EXECUTIVE SECRETARY

April 2, 2002

HAND DELIVERED

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
State Capitol, 12th Floor
Bismarck, ND 58505

RE: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rates Investigation
Case No. PU-399-01-186

Dear Mr. Mielke:

Enclosed please find an original and seven copies of the following in regard to the above-captioned matter:

1 BRIEF OF MONTANA-DAKOTA UTILITIES CO.; and
2 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

I have also enclosed an extra copy to be filed stamped returned with our courier.

Very truly yours,

PEARCE & DURICK

By
William P. Pearce

WPP/leo
Enclosure
cc: Mr. Don Ball - (w/enc.)

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Cover letter re filings
by Montana-Dakota Utilities Co., a Division of MDU Re
04/02/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

APR - 2 2002

BEFORE THE PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Electric Rates Investigation

Case No. PU-399-01-186

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

On September 7, 2001, the North Dakota Public Service Commission Staff [hereinafter "Staff"] issued a complaint, pursuant to N.D.C.C. § 28-32-05, alleging that Montana-Dakota Utilities Co.'s [hereinafter "Montana-Dakota"] existing filed rates for providing electric service in North Dakota are unjust and unreasonable, on the claimed grounds that Montana-Dakota is recovering more revenue than necessary to earn a reasonable return on its investment used and useful in providing such service. The complaint alleged that Montana-Dakota's rates should be adjusted to reduce annual North Dakota electric revenues by $9.155 million annually, and sought a decision by the Public Service Commission [hereinafter the "Commission"] requiring implementation of rates that would produce said revenue reduction. The complaint was served by mail on Montana-Dakota on September 20, 2001.

Montana-Dakota filed its answer to the complaint, pursuant to N.D.C.C. § 28-32-05, on October 9, 2001, admitting the standard jurisdictional allegations but denying that its filed rates were unjust or unreasonable or that any excess electric revenues were being earned for North Dakota service, and seeking a dismissal of the Staff's complaint.

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Proposed Finding of Fact, Conclusions of Law and Order
by Montana-Dakota Utilities Co., a Division of MDU R

04/02/2002 CC: Comm Legal Illona, Pat, Jerry Mike

On November 21, 2001, the Commission issued a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline, setting the public hearing in this matter for February 25, 2002, and scheduling informal public input sessions via interactive television on December 11, 2001, in Bismarck, Dickinson and Williston. The public input sessions were held at said time and places, and several members of the public made appearances in Dickinson.

Pursuant to the Notice of Hearing, the Commission held the public hearing at the State Capitol in Bismarck on February 25-26, 2002, on the following issues:

1. What is the value of Montana-Dakota's property, used and useful for the service and convenience of the public in North Dakota?

2. What is Montana-Dakota's rate of return on its property, used and useful for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on Montana-Dakota's property, used and useful for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on Montana-Dakota's property, used and useful for the service and convenience of the public in North Dakota?

5. Are Montana-Dakota's rate schedules designed in such a manner that they will result in a basis of charge to its customers that is just and reasonable without discrimination?

No person intervened or sought intervention in this matter and no members of the public appeared at the public hearing.

In its written rebuttal testimony submitted on February 11, 2002, the Staff updated its position using new financial information and reduced its initial complaint of excess earnings from

$9.155 million to $7.327 million. At the public hearing, the Staff again amended its position, recommending instead that Montana-Dakota's rates should be adjusted to reduce revenues by $4.941 million annually.

Montana-Dakota took the position that its rates should not be adjusted. Although the evidence the Company presented showed an annual revenue deficiency of $1.727 million, Montana-Dakota did not seek an increase in its rates to meet such deficiency.

FINDINGS OF FACT

Jurisdiction

1. Montana-Dakota is a Division of MDU Resources Group, Inc. and is a public utility providing both electric and natural gas services to customers in North Dakota, South Dakota, Montana and Wyoming.

Test Year

2. The appropriate test year to be used for determining Montana-Dakota's rate base for this proceeding is 2001, adjusted for certain known and measurable changes projected for 2002.

Rate Base

3. Based upon the evidence received at the public hearing, the appropriate rate base for Montana-Dakota's North Dakota electric service is $128,902,000, determined as follows:

Projected 2002 (Thousands)				
Description	2001	Adjustments	Adjusted	Average
Plant in Service	$379,126	$4,325	$383,451	$381,289
Less: Accumulated Depreciation	$215,094	$71	$215,165	$215,130
Construction Work in Progress	$518	$0	$518	$518
Net Plant in Service	$164,550	$4,254	$168,804	$166,677
Materials and Supplies	$2,909	$0	$2,909	$2,909
Fuel Stocks	$1,255	$0	$1,255	$1,255
Prepayments	$99	$15	$114	$107
Accumulated Deferred Income Taxes	($39,774)	($65)	($39,839)	($39,807)
Accumulated Deferred ITC's	($2,229)	$0	($2,229)	($2,229)
Customer Advances	($10)	$0	($10)	($10)
Rate Base	**$126,800**	**$4,204**	**$131,004**	**$128,902**

Cost of Capital

4. Montana-Dakota's present capital structure consists of long-term debt, preferred stock and common stock (common equity). The Commission finds that the present capital structure consists of 45.90% long-term debt, 5.23% preferred stock and 48.87% common equity and that said capital structure is just and reasonable for the determination of rates herein.

5. The cost rate of Montana-Dakota's $16,500,000 in preferred stock was not disputed in this proceeding, and the Commission finds that it is 4.63%.

6. Expert testimony on behalf of the Staff and on behalf of Montana-Dakota was presented pertaining to the determination of the cost of the Company's $144,894,000 in long-term debt. The Commission finds that the yield-to-maturity methodology for calculating the cost of long-term debt best reflects the true effective cost of debt capital because it is based on actual amounts

and the actual timing of cash flows, and notes that this methodology is required for ratemaking purposes in proceedings under the jurisdiction of the Federal Energy Regulatory Commission. Accordingly, the long-term debt cost rate of 9.22% for Montana-Dakota determined using the yield-to-maturity methodology is found to be appropriate.

7. Expert testimony on behalf of the Staff and on behalf of Montana-Dakota was presented pertaining to the determination of the cost of Montana-Dakota's $154,250,000 in equity capital. The Commission finds, based on analysis of business, regulatory, financial and market risks faced by comparable utility companies, including both electric-only and combination (gas and electric) companies, and upon recognizing the necessary flotation cost adjustment testified to by Montana-Dakota's expert witness J. Stephen Gaske, that the appropriate cost of equity capital for Montana-Dakota is 12.75%.

8. Accordingly, the Commission finds that the overall rate of return on rate base which should be allowed for Montana-Dakota is 10.70%, determined as follows:

Source of Capital	Percentage in Capital Structure	Cost Rate	Contribution to Overall Rate of Return
Long-term Debt	45.90%	9.22%	4.23%
Preferred Stock	5.23%	4.63%	0.24%
Common Equity	48.87%	12.75%	6.23%
TOTAL:	**100%**		**10.70%**

Revenues from Sales for Resale (Wholesale Sales)

9. A major issue in this case is the level of margins on sales of electric power for resale, that is wholesale sales of power which Montana-Dakota makes to other retailers. The margins realized by the Company on such sales result from two factors: the actual Mwh of power sold and the price per Mwh paid by the purchaser. The evidence presented by Montana-Dakota showed that margins earned through wholesale electric power sales ("sales for resale margins") during the 2001 test year, as well as during the original proposed 2000 test year, arose from anomalies in the wholesale electric market, including a scarcity of available generation and very high natural gas prices that would not recur in 2002 or in any foreseeable succeeding year. Montana-Dakota's witness Terry Blinsky testified that the price per Mwh paid to the Company under a wholesale electric contract negotiated in March 2001, covering and setting prices for the 2001 summer peak season, was very favorable because the contract was negotiated at a time when market conditions projected abnormally high electric prices for the 2001 summer peak season. The undisputed expert testimony of Montana-Dakota witnesses Paul Wilkinson and Roger Schiffman showed that the natural gas market when this contract was entered into was very tight and prices were at a decade-high level, resulting in strong upward pressure on electric prices. The testimony of Blinsky, Schiffman and Wilkinson showed that this situation will not recur in the foreseeable future, demonstrating that the large margins achieved by the Company under the 2001 contract will not be achievable in 2002. The Commission finds that the upper limit of the likely levels of wholesale sales margins in more normal market conditions would result from applying the current market estimated prices to the same level of Mwh sales as were made during 2001, as the Company did in its presentation, resulting in an estimated margin level of approximately $6,430,000 for 2002.

Accordingly, the Commission approves an amount of $6,430,000 as the appropriate level of adjusted test-year wholesale sales margins for this proceeding.

Operating Expenses

10. The evidence shows that due to higher than normal temperatures and summer load peaks that occurred in 2000 and 2001 Montana-Dakota was unable to meet its reserve capacity obligations imposed by its membership in MAPP (Mid-Continent Area Power Pool) and that accordingly monetary penalties will be assessed in accordance with the MAPP rules and will be payable in 2002 and 2003. The Commission recognizes that the anomalous weather conditions giving rise to the penalty could not be fully foreseen, and determines that the cost that would have been incurred in securing the additional 16.9 megawatts of capacity required to meet the MAPP peak requirement during the summer of 2001, rather than the actual penalty, is the appropriate amount that should be allowed as an operating expense, since this is the actual cost that would have necessarily been incurred in order to avoid the imposition of a penalty. The evidence presented shows that the cost for additional capacity is approximately $4,000 per megawatt month, so that the cost for the additional 16.9 megawatts in capacity for four months would be approximately $270,000 on a total Company basis, or $186,000 for the portion allocated to North Dakota. The Commission accordingly finds that an amount of $186,000 should allowed in North Dakota operating expenses to account for this item.

11. An adjustment to reflect a three-year amortization of major maintenance expenses at the Antelope Valley Unit II generating station resulting from Montana-Dakota's long-term power purchase contract with Basin Electric Cooperative was not disputed between the parties. This

amount, which is found to be proper by the Commission, equates to an annual expense reduction of $920,000 on a Company system-wide basis as applied to the 2001 test period.

12. An adjustment to reflect an annual loss in revenues of $563,000 resulting from Montana-Dakota's participation in the Midwest Independent System Operator Inc. (M ISO) regional transmission organization (RTO), pursuant to FERC order No. 2000, was not disputed between the parties. The inclusion of this revenue reduction is found to be proper by the Commission.

13. The adjustment proposed by Montana-Dakota to labor costs to reflect actual wage increases experienced for 2001 and 2002, was not disputed by the Staff, and the Commission finds the amounts proposed by the Company to be proper and allowable as proper operating expenses.

14. Montana-Dakota introduced evidence showing that its pension and post-retirement benefit costs will increase substantially in 2002, from the 2001 test year amounts, in an amount of $241,000 applicable to North Dakota operations, due to the decline in asset returns from the abnormally high returns received in recent years and the decline in discount rates to reflect current long-term interest rates, both of which result in increased pension and benefit costs. The Commission finds this adjustment to be appropriate and accordingly allows this item of $241,000 as an operating expense increase.

15. Montana-Dakota introduced evidence showing that the portion of the annual cost of its Supplemental Income Security Program (SISP) allocable to North Dakota electric operations is $683,000. The SISP program is a supplemental pension benefit designed to attract and retain key employees. The Company has not previously sought to include the cost as a recoverable item of operating expense. The Commission finds that such plans are common in the industry and that the SISP program is beneficial to Montana-Dakota customers and serves the public interest by helping

to insure a high-quality management of the Company. Accordingly, the Commission finds this adjustment to be appropriate and allows this item of $683,000 as an operating expense.

16. The evidence shows that Montana-Dakota's insurance expense has increased and that such increases were exacerbated as a result of the terrorist attack upon the United States on September 11, 2001. The record in this case reflects that insurance expenses for 2002 have increased by the amount of $155,000, and accordingly the Commission finds this adjustment to be appropriate and allows this item of $155,000 as an increase in operating expense to reflect actual current prevailing conditions.

17. The adjustment proposed by Montana-Dakota to include approximately $33,000 in contributions to Energy Share of North Dakota and the Lignite Energy Council as allowable operating expenses was not disputed by the Staff. The Commission finds such contributions to be proper and in the public interest and accordingly allows this item as an operating expense.

18. The evidence offered by the Staff noted what it deemed to be an abnormally high level of office supplies expense in 2001, and accordingly Staff proposed using a figure representing a 5% increase over the 2000 level, rather than the actual 2001 level, resulting in a proposed disallowance of $678,000 in 2001 expenses. The evidence presented by Montana-Dakota, however, showed that the 2001 increase resulted from costs associated with a corporate aircraft, increased costs for computer infrastructure and telephone expense, as well as some reclassification of fees from other accounts, all of which will be continuing costs on a year-to year basis, rather than one-time increases experienced only in 2001. The Commission finds that these will be annual costs and accordingly no adjustment from actual 2001 levels should be made.

19. Based on the above Findings of Fact and the resolution of certain matters as discussed

above, the Commission finds that there is no basis to support a revenue reduction in Montana-Dakota's electric operations at this time. In fact, there exists a revenue deficiency, but, as Montana-Dakota has not sought a rate increase, none is appropriate in this proceeding.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the parties to and the subject matter of this proceeding.

2. The Staff bears the burden of proof in this proceeding to demonstrate that a preponderance of the evidence shows that Montana-Dakota's North Dakota electric rates now in effect produce revenues that are excessive and therefore are not just and reasonable.

3. The preponderance of the evidence demonstrates that the current Montana-Dakota electric rates in effect in North Dakota are just and reasonable, and do not produce revenues that are excessive.

4. The complaint herein should accordingly be dismissed, with prejudice.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes the following

ORDER

The complaint herein is hereby in all things dismissed, with prejudice.

Bismarck, North Dakota. April ____, 2002.

PUBLIC SERVICE COMMISSION

_____

Susan E. Wefald, President

_____

Leo M. Reinbold, Commissioner

_____

Anthony T. Clark, Commissioner

STATE OF NORTH DAKOTA

BEFORE THE PUBLIC SERVICE COMMISSION

APR - 2 2002
EXECUTIVE SECRETARY

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Electric Rates Investigation

Case No. PU-399-01-186

BRIEF OF MONTANA-DAKOTA UTILITIES CO.

Introduction

This proceeding was initiated by the filing of a complaint by the North Dakota Public Service Commission Staff [hereinafter the "Staff"], seeking to have the Commission order a reduction in Montana-Dakota's North Dakota electric rates. As the moving party in this proceeding, the Staff therefore has the burden of proof, as well as the burden of going forward with the evidence, as the Administrative Law Judge pointed out:

> The burden of proof today is on the complainant, the PSC staff, to show by the preponderance or the greater weight of the evidence that in the public interest MDU's electric service rate should be changed to reduce annual revenues by 9.155 million, or to show that other administrative action as a result of the staff complaint is appropriate." [Tr. p. 12]

The complainant's burden of proof is the same in an administrative proceeding as in a judicial proceeding. Morrell v. North Dakota Department of Transportation, 598 N.W.2d 111 (ND 1999), Kobilansky v. Liffrig, 358 N.W.2d 781 (ND 1984).

Since the Staff bears the burden of proof, the Commission may adopt the Staff position only

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if it has presented substantial evidence in support of the position, and that evidence must have been a preponderance of the entire evidence in the record. Prairieview Nursing Home v. North Dakota Department of Human Services, 598 N.W.2d 116 (ND 1999); Wahl v. Morton County Social Services, 574 N.W.2d 859 (ND 1998). The Commission's decision must be such that a reasoning mind could reasonably have determined the factual conclusions reached were proved by the weight of the evidence in the record. Application of Skjonsby Truck Line, Inc., 357 N.W.2d 227 (ND 1984); Ganske v. North Dakota Workmen's Compensation Bureau, 355 N.W.2d 800 (ND 1984). This is a higher standard than the "clearly erroneous" test, which has no application to review of administrative agency findings of fact. O'Brien v. North Dakota Workmen's Compensation Bureau, 222 N.W.2d 379 (ND 1974). The Commission's conclusions of law and order must then be sustained by findings of fact that have been proved by the weight of the evidence. Bank of Hamilton v. State Banking Board, 236 N.W2d 921 (ND 1975).

The written testimony initially filed in this matter by the Staff raised a number of issues pertaining to adjustments to rate base, allowable operating expenses, revenues from wholesale electric sales and resulting margins, and the cost of capital (permitted rate of return on rate base). As a result of the submission of Montana-Dakota's written direct testimony, followed by the submission of the Staff 's written rebuttal testimony and Montana-Dakota's written surrebuttal testimony, certain of these issues were eliminated. In particular, there are no remaining issues with regard to the amount of the test year rate base. [Tr. p. 23]. Accordingly, this brief addresses only the remaining issues that are disputed between the parties.

I. Wholesale Electric Sales Margins

The issue of Montana-Dakota's margins on wholesale sales of electric power constitutes, as Staff witness Mike Diller pointed out, "most of the case." [Tr. p. 30]. Montana-Dakota introduced clear expert evidence showing that the margins earned through wholesale electric power sales (sometimes referred to as sales for resale margins) during the 2001 test year, as well as during the original proposed 2000 test year, arose from anomalies in the wholesale electric market that would not recur in 2002 or in any foreseeable succeeding year. The record is completely devoid of any evidence, however, in support of the Staff's use of the 2001 level of sales for resale margins, or the average of the sales for resale margins for the last three years (as proposed by Mr. Diller in testimony during the hearing; Tr. p. 34-35), as a proxy for determining the amount of such margins likely to be generated by wholesale sales in 2002. Not only is there no substantial evidence to support the Staff's position; there is none. Mr. Diller admitted that Montana-Dakota had presented a substantial amount of evidence in support of all of the factors that determine future resale margins and that he "thought they were pretty good" [Tr. p. 33]. He dismissed all of this evidence, however, with the unsupported observation that "I think the uncertainties of the future warrant the consideration of actual results as a proxy for future rates." [Tr. p. 34]. The fundamental fallacy of this reasoning is that the "actual results" Mr. Diller relied upon are the 2001 wholesale electric margins which Montana-Dakota's unrefuted evidence showed arose from highly unusual market conditions that would not recur in succeeding years.

Mr. Diller conceded that the market factors testified to by Montana-Dakota all affect the price of electricity, and therefore the resale margins, but then concluded that "it is difficult to determine to what degree such things will have on future off-system sales or the price of those sales. A fair bit

of judgment will be required by the commission to decide this issue" [Ex. 4, p. 8]. The Commission must always exercise its informed judgment in weighing the evidence in the record in reaching its conclusion, of course, but here the Staff offered no evidence whatsoever on which the Commission can reach a conclusion. There must be evidence on which the Commission can base its decision, as an agency decision without a rational basis in the record is arbitrary and capricious. Tri-County Electric Coop., Inc. v. Elkin, 224 N.W.2d 785 (N.D. 1974).

The undisputed testimony of Montana-Dakota's witness Terry Blinsky showed that the reason for the abnormally high resale margins achieved in 2001 was that high electric prices had been locked in under the terms of a contract signed in March 2001, based on future prices then in effect for the summer peak season, even though prices actually in effect later in 2001 were declining:

> "Very simply, the reason that sales for resale margins remained up in 2001 was that Montana-Dakota was successful in entering into a contract with a buyer in March 2001 that covered the summer season of 2001. At the time the contract was executed, prices of gas and electricity were still relatively high and the buyer agreed to pay essentially the future price that existed at the time the contract was executed. Thus even though electric prices fell during 2001, as did the gas price, the revenues received by Montana-Dakota were dictated by the contract and the buyer was obligated to pay the contract price rather than the current price at the time of delivery. Absent this contractual arrangement, Montana-Dakota would not have been able to retain the margins it did in 2001." [Tr. p. 348-49]

All of the evidence in the record shows that this condition will not be repeated in the foreseeable future. Montana-Dakota's witness Roger Schiffman testified in discussing the 2001 contract, that "under current market conditions contracting opportunities such as that enjoyed by Montana-Dakota are no longer available because the premium between contract and spot market prices is substantially smaller. ... The price spikes we experienced recently in the winter of 2000-2001 were clearly an anomaly." [Tr. p. 286]. Those market conditions are influenced by "weather,

fuel prices, economic growth, generation mix, and the supply-demand balance [which] all play important roles in defining trends in the broader wholesale power markets." [Tr. p. 279] "The Staff offered no evidence to refute Mr. Schiffman's conclusion that a variety of unusual market factors had resulted in "abnormally high profit margins for coal-fired generators throughout the first months of 2001" when this contract was entered into. [Tr. p. 288]. The outlook for 2002 and the foreseeable future is for a much less profitable scenario for off-system sales:

> This combination of factors points to lower and more stable wholesale electricity prices in the MAPP region for 2002 compared to the price and volatility levels seen over the last four years and particularly during the first half of 2001. ... With lower and more stable natural gas and electricity prices, profit margins on off-system sales will be correspondingly lower. ...Montana-Dakota will face greater competition for off-system sales.
> ...
> In summary, market conditions toward the end of 2001 are significantly more representative of what can be expected in 2002 and for the foreseeable future." [Tr. p. 290-292]

Not only will the profit margins decrease, but also the volumes of wholesale electric power that can be marketed will most likely less be in the future than in 2000 and 2001. As Mr. Schiffman further pointed out:

> "With lagging electricity sales due to the current economic downturn, that competition will only be greater and Montana-Dakota might face reduced volumes of off-system sales, in addition to lower profit margins on those sales. " [Tr. p. 291-92]

For this reason the margins from wholesale sales projected by Mr. Blinksy are in fact probably higher than can actually be achieved, since those projections are based on the same future wholesale sale volumes being achieved as were actually achieved in the last twelve months prior to this hearing. [Ex. 10]. Montana-Dakota has no contracts for off-system sales in place now or for the upcoming peak summer season, in stark contrast with the situation a year ago in March 2001 when the very

favorable contract was in place. [Tr. p. 350].

None of the evidence was refuted and there is therefore simply no basis for ignoring all of the changes in the wholesale electric sales markets. Nor is there any evidence that the anomalous scenario that was in place during 2000 and 2001 is a realistic model for what will happen from this point on. Montana-Dakota presented testimony through both Mr. Schiffman and Mr. Blinsky as to what the most probable level of current prices is likely to be, based on the best indicators available. These are the nationally recognized futures markets referred to as the NYMEX and the Intercontinental Exchange. Futures markets provide a reasonable method for projecting the wholesale price of electricity at any given time into the future. For example, the March 2001 NYMEX futures prices formed the basis for the 2001 summer peak prices built into the contract which Montana-Dakota entered into in March 2001. In March 2001, those projected prices were the best indicator of what wholesale electric prices would be during the future period in which the contract would be in effect. [Tr. p. 348-49]. Projecting energy prices into the future, as Mr, Schiffman stated, is not a simple matter, but the established futures markets provide a basis for doing this:

> "Forecasting energy market prices is always a difficult exercise, and using the prices of currently traded future contracts is a reasonable way to assess current market expectations of spot market prices that will prevail during the relevant months of 2002." [Tr. p. 292]

As Mr. Blinsky pointed out, the use of futures prices are appropriate because they represent the prices of actual transactions between willing sellers and willing buyers and therefore "are used as a guide by market participants when buying or selling energy." [Tr. p. 354]. As a check on the NYMEX futures prices which Mr. Blinsky used in projecting future wholesales margins, he made

a comparison with the margins that would be predicted by using the Intercontinental Exchange Prices, which had been testified to by Mr. Schiffman [Ex. 9]. The result was a projected 2002 margin of $6,080,199, which is strikingly close to the $6,428,778 margin projected using the NYMEX futures. The close correspondence between the two methods underscores the inherent reliability of this approach to projecting future wholesale prices. No other evidence was introduced in support of future wholesale electric price levels and this is clearly the evidence of what kinds of margins Montana-Dakota can be expected to achieve in the future. Experience has now borne this out, as Montana-Dakota's actual wholesale sales margins for the first quarter of 2002 were $1.6 million. Annualizing this level gives a twelve-month total of $6.4 million, which is essentially the 2002 projected level testified to by Mr. Blinsky. [Tr. p. 353].

II. Cost of Capital

The testimony of Montana-Dakota's expert witness J. Stephen Gaske showed that the weighted cost of capital, that is the allowed rate of return on the rate base which should be approved in this proceeding, is 10.70%. The weighted cost of capital includes the usual elements of equity capital, long-term debt and preferred stock. There is no dispute in this matter as to the 4.63% cost of Montana-Dakota's preferred stock, which accounts for 5.23% of the capital structure.

Long-Term Debt

Dr. Gaske, however, however, testified that the true cost of Montana-Dakota's long-term debt is 9.22%, as opposed to the 8.62% cost of long-term debt testified to by the Staff's expert witness Charles King. The 9.22% level was derived by the use of the yield-to-maturity method, which this Commission has approved as the proper methodology and which is required to be used by FERC in

rate proceedings under its jurisdiction. Mr. King utilized the accounting approach to derive his 8.62% for the sole reason that he deemed that Montana-Dakota's cost of long-term debt "is way out of line with that of other utilities." [Tr. p. 94-5]. Mr. King's conclusion is based solely on his comparisons with embedded debt costs of the two other public utilities that serve electric customers in North Dakota (Xcel Energy, Inc. - 6.99%, and Otter Tail Power Company - 7.68%). No evidence was offered, however, as to why the debt costs of these two utilities are at these particular levels and no meaningful comparison can be made among utility cost of debt capital levels without examining the makeup and timing of the specific debt capital structures. Montana-Dakota, on the contrary, presented undisputed evidence as to why its debt cost is at the level it is, resulting primarily from debt originally issued in connection with the construction of the Coyote electric generating facility late in the 1970's, at a time when debt costs were high. There has been no suggestion that the Coyote Plant investment was not a prudent one or that it has not provided good service, but it was constructed at a time of high cost financing, as Dr. Gaske pointed out:

> "They [Montana-Dakota] were building an electric plant, and anyone who remembers that time period remembers that very suddenly interest rates went to extremely high levels and stayed there through the early Eighties.... So the company had a very large need for financing at the same time that interest rates were very high. It issued a very high cost debt at that time ... The plant is still in service. It provides, as I understand, very economical service to the ratepayers, but the fact of the matter is that plant was built at a high cost in terms of what they had pay for interest at the time." [Tr. p. 158-59]

Montana-Dakota's witness Douglass Mahowald demonstrated how the Company has continued to act prudently and in the public interest to reduce its embedded debt cost by refinancing if, and whenever, any savings in cost can be achieved. If the market conditions at any time are such that debt costs can be saved by refinancing, the Company does so. Thus, for example, in 1992

Montana-Dakota refinanced its long-term debt because it was able to achieve an annual savings of $231,500. [Tr. p. 371-72]. Conversely, if the market conditions are such that the total cost of debt after a refinancing, including the necessary cost of reacquiring the old debt, would be higher than the existing cost, it would clearly not be prudent to refinance the debt simply to obtain a lower coupon rate, because the actual total cost would be higher. In that case refinancing would be not be in the public interest and therefore the Company would not do it. [Tr. p. 373-74]. As Dr. Gaske pointed out:

> "The real issue with regard to the debt cost has to do with reacquisition costs ... The company refinanced in 1986 to get the cost down, and – but they still had high cost debt that in 1992 they again refinanced. So what you really see on the books of Montana-Dakota today is – are debt costs that are right in line with everybody else except for the fact that they have some high reacquisition costs that have been carried over quite a number of years and really from a time period that they needed to build a new plant and raise a lot of money at high interest rates.
> ....
> When you look at the overall circumstances and delve into them a little bit .. you find that their debt costs are perfectly reasonable considering the circumstances under which they were incurred." [Tr. p. 158-59]

Mr. King stated that he did "not understand why it would be impossible for this company [Montana-Dakota] to reduce its debt costs." [Tr. p. 96]. The evidence presented by the Company demonstrated why that is impossible and that Montana-Dakota continuously attempts to keep its debt costs as low as possible. In fact, all of the Montana-Dakota debt issues that have occurred since the 1992 refinancing of the original high cost debt from the 1970's have an average cost of 7.31%, comparable to the debt costs for Xcel Energy and Otter Tail Power which were the basis for Mr. King's comparisons. [Tr. p. 157]. Once the reacquisition costs of the early high-cost debt are fully accounted for , as Dr. Gaske pointed out, Montana-Dakota's debt costs will be similar to those of the other utilities serving North Dakota:

"At some point in the future as the reacquisition costs are paid down and the current debt that those reacquisition costs are associated with, as that disappears off their books, they will – their costs will drop down to a level that's probably commensurate with everybody else." [Tr. p. 160]

Equity Capital

Comparable Companies

Dr. Gaske also testified that the appropriate cost of equity capital is 12.75%, whereas Mr. King's testimony was that the appropriate rate is 11.7%. The primary points of difference between these two figures arise from the use of a flotation cost adjustment by Dr. Gaske and his use of both combination utilities (gas and electric) and electric-only utilities in his comparable company analysis, as long as the companies derive at least 75% of their revenue from electric operations [Tr. p. 164], whereas Mr. King eliminated electric-only utilities. The basis for Mr. King's approach is that he believes that the risk for combination companies like Montana-Dakota is less than the risk for electric-only companies, thereby justifying a lower rate of return for the less risky company. It is submitted that Dr. Gaske's analysis is the more reasonable: That the typical investor will assess the risks of the electric operations if he is investing in the hope of making a given return on electric operations and similarly will assess the risks of the gas operations if he is investing in the hope of making a given return on gas operations, and that these risks will be analyzed separately:

> Now one of the points he [Mr. King] makes is that, well gas and electric compete with each other, and therefore if the same company owns both, it really is indifferent as to what happens and that somehow reduces the risk of investing in one or the other. That's not true for several reasons.
>
> First, and by far the most important one, is the fact that when you sit down and you try to – to decide whether to invest in, say, a new generating plant or a transmission line, you look at the risks that that faces. You look at the electric market, you look at competitive alternatives, and you make the investment.

> If the investment later goes bad and you lose your money, you know, that's part of the risk, but it's the risk of the electric operation that you're considering when you make your electric investment. It's not the risk of the combination company, because when you're investing in the gas business, you sit down separately and say, what's the risk of investing in the gas business, and you make investments there, and they may or may not pan out." [Tr. p. 167-68]

Accordingly, Dr. Gaske's use of both combination companies and electric-only companies provides an appropriate group of comparable companies, and his requirement that his comparable companies derive at least 75% of their revenues from electric operations assures that his group of companies is appropriate as a basis of comparison with Montana-Dakota. The 75% requirement assures that the comparison companies will be tend to be in the same market situation as Montana-Dakota:

> "The issue in this case – I mean, the really big issue is this case is the sales for resale by Montana-Dakota, and if you're looking for companies that are comparable to Montana-Dakota, I can't think of a company that would be more comparable than one that is making sales for resale, in addition to having a high percentage of their revenues in the electric business." [Tr. p. 170]

Flotation Cost

The basis for allowing a rate of return on equity capital, often referred to as the cost of equity capital, is that a utility company should be in a position to be able to raise equity capital by issuing common stock at any time. The generally accepted method for determining the proper cost of equity capital is the DCF (discounted cash flow) analysis employed by the expert witnesses for both Montana-Dakota and the Staff. That method is based on the premise that the stock price must be sufficiently above book value that stock can be issued without diluting the value of existing shareholders' investments, and this requires the inclusion of an allowance for the " flotation cost," that is the cost associated with issuing stock (underwriting commissions, filing fees, etc.) that reduce the net proceeds of issuance below the total amount actually received. As Dr. Gaske points out, this

means that "if the proceeds on a issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value [*i.e.* 1/91%]." (quoting from Gordon, The Cost of Capital to a Public Utility, p. 165-66 (1974)) [Ex. 7, JSG 3, p. 8].

This goal can only be achieved if the flotation cost adjustment is applied to the entire rate of return, and the appropriate adjustment, as testified by Dr. Gaske, is approximately 4.75 percent:

> The experience of other electric companies suggests that a flotation cost adjustment of 4.75 percent is required to ensure that the allowed rate of return is sufficient to attract capital on reasonable terms. [Ex. 7, JSG 3, p. 7-8]

A rate of return which does not include the flotation cost adjustment, amounting to approximately $363,000 in this case, is necessarily inadequate. [Tr. p. 172, 176].

III. Operating Expenses

Supplemental Income Security Program

Montana-Dakota introduced evidence showing that the portion of the annual cost of its Supplemental Income Security Program (SISP) allocable to North Dakota electric operations is $683,000. The SISP program is a supplemental pension benefit designed to attract and retain key employees. These kinds of programs, which have in the last few years become commonplace in the utility industry due to changes in federal regulations pertaining to retirement benefits and Social Security benefits, are essential "in order to attract, retain and provide equitable benefits for key employees." [Tr. p. 410]. The costs associated with providing the SISP program are therefore just and reasonable expenses incurred in providing high quality utility service to Montana-Dakota's customers and should be allowed as operating expenses. As the Company's witness Richard Espeland summarized:

"The SISP is a common type of benefit provided in today's business environment. The combined replacement income from all retirement plans when taken together is equitable, reasonable and justifiable. The SISP recognizes the contributions of key employees whose abilities and vision have enabled Montana-Dakota to streamline operations, reduce costs and employee numbers, implement new technologies and, more importantly to the ratepayer, to keep Montana-Dakota's electric rates at 1987 levels at a time when the Consumer Price Index rose 59 percent during the same period of time." [Tr. p. 414-15].

Office Supplies Expense

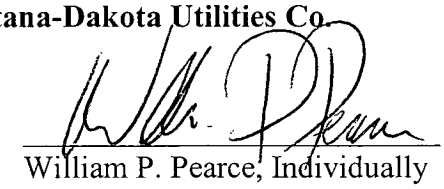
The evidence offered by the Staff noted what it deemed to be an abnormally high level of office supplies expense in 2001, and accordingly Staff proposed using a figure representing a 5 percent increase over the 2000 level, rather than the actual 2001 level, resulting in a proposed disallowance of $678,000 in 2001 expenses. The undisputed evidence presented by Montana-Dakota, however, shows that the 2001 increase resulted from costs associated with a corporate aircraft, increased costs for computer infrastructure and telephone expense, as well as some reclassification of fees from other accounts, all of which will be continuing costs on a year-to-year basis, rather than one-time increases experienced only in 2001. There was no evidence offered to suggest that these costs were unreasonably or imprudently incurred and therefore they should be allowed as increased operating expenses.

CONCLUSION

The great preponderance of the evidence in the record demonstrates that there is no basis for a reduction in revenues for Montana-Dakota's electric operations in North Dakota and therefore the complaint should be dismissed.

Dated April 2, 2002.

Montana-Dakota Utilities Co.

By 

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State of North Dakota

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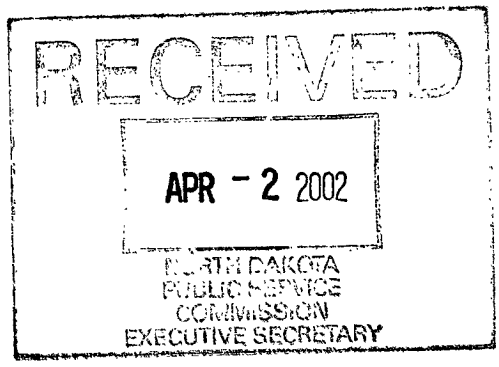
April 2, 2002



Jon Mielke, Executive Secretary
North Dakota Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505

RE: PU-399-01-186
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Mielke:

Enclosed is the original and seven copies of staff's proposed Findings of Fact, Conclusions of Law and Order in the above noted proceeding.

Sincerely,

William W. Binek
Chief Counsel

wwb/sdh

Enclosure

c: Don Ball, MDU
William Pearce

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Cover letter re Proposed Findings

by Public Service Commission

04/02/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

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NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

April 2, 2002

Appearances

Commissioners: Susan E. Wefald, Leo M. Reinbold, Anthony T. Clark.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy Staff.

William P. Pearce, Attorney at Law, 314 E. Thayer Ave., PO Box 400, Bismarck, ND 58502-0400, appearing for Montana-Dakota Utilities Co.

Douglas W. Schultz, Senior Attorney, MDU Resources Group, Inc., PO Box 5650, Bismarck, ND 58506-5650, appearing for Montana-Dakota Utilities Co.

Patrick J. Fahn, Utility Analyst, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing as advisory Staff for the Public Service Commission.

Allen C. Hoberg, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

On September 7, 2001, the North Dakota Public Service Commission advocacy staff (staff) filed a complaint against Montana-Dakota Utilities Co. (MDU), a division of MDU Resources Group, Inc., alleging that MDU's rates result in excess revenue collections of $9.155 million per year.

On September 19, 2001, the North Dakota Public Service Commission (Commission) found that staff's complaint states a *prima facie* case.

On November 5, 2001, Public Service Commissioner, Susan Wefald, solicited responses from the parties in the case regarding the applicability of handling off-system sales revenue through the fuel adjustment clause and whether the Commission should consider incentives to encourage future off-system sales. The staff's reply argued for no change in existing policy thereby excluding off-system sales profits from the fuel adjustment clause but provided a number of incentive plans used by other state commissions to encourage the selling of off-system sales. MDU's reply stated that any discussions should focus on the need for incentives and a proper balance of the risks and rewards.

On November 13, 2001, MDU filed a letter confirming the procedural schedule agreed to by MDU and staff.

On November 21, 2001, the Commission issued a Notice of Hearing and Notice of Public Input Session. The notice set forth the following issues for consideration in the proceeding:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On December 11, 2001, the Commission conducted a Public Input Session via interactive videoconference, with hearing sites in Bismarck, Dickinson and Williston. The public input included concerns about escalating prices requiring the lowering of thermostats, a commendation for reliable service, questions concerning changes in company wide earnings and stock prices, concerns about the workability of investor owned utilities in conjunction with rural electric cooperatives and, general questions about deregulation and alternative forms of regulation. Staff and MDU responded to all questions.

On January 11, 2002, MDU's six witnesses filed direct testimony arguing that rates do not need to be changed.

On February 11, 2002, staff's two witnesses filed its rebuttal testimony reducing its initial complaint of excess earnings from $9.155 million to $7.327 million.

On February 19, 2002, MDU added four new witnesses and filed its surrebuttal testimony arguing that rates do not need to be changed.

On February 25 and 26, 2002, the Commission conducted a formal hearing as scheduled. No motions to intervene were filed. On March 5, 2002, MDU filed late-filed exhibits.

On March 7, 2002, the Commission held a working session to discuss the issues and clarify whether additional late filed exhibits or information were necessary.

The Commission, having reviewed the evidence in the record and submittals in support thereof, makes the following:

Findings of Fact

1. MDU is a utility company operating as a division of MDU Resources Group, Inc. MDU provides retail electric service to approximately 70,000 customers in North Dakota.

2. Advocacy staff witness Mike Diller testified that the commission should continue to use rate of return regulation as it has in the past. Diller identified the primary components of rate of return regulation as rate base, cost of capital and net regulated income. He explained how the components are used to determine if MDU's rates should be adjusted and provided the Commission with worksheets for use in its deliberations.

3. Many of the issues in this proceeding were resolved between the parties through the filing of direct, rebuttal and surrebuttal testimony, as well as oral testimony at the hearing. Except for the specific exceptions noted below, the parties do not dispute the:

- Jurisdictional cost of service study.
- Test year rate base.
- Capital structure.
- Cost of preferred equity.
- Test year revenues (except for sales for resale margins).
- Test year expenses (except for administrative and general expenses).

4. Diller presented historical rate base amounts reported by MDU and test year rate base levels for this proceeding. MDU did not object to any of Diller's historical representations. Through surrebuttal testimony, MDU agreed to Diller's test year value for rate base. The commission finds that the following schedule accurately depicts North Dakota's historical rate base levels as well as a reasonable test year rate base as agreed to by advocacy staff and MDU.

	(Thousands)			
	Reported by MDU			2002
Description	1999	2000	2001	Test Year
Plant in Service	$366,890	$375,347	$379,126	$381,289
Accum. Res. for Depreciation	193,286	202,071	215,094	215,130
Avg. Net Plant in Service	$173,604	$173,276	$164,032	$166,159
Constr. Work in Progress	2,572	850	518	518
Materials & Supplies	3,252	3,202	2,909	2,909
Fuel Stocks	1,192	1,277	1,255	1,255
Prepayments	265	209	99	107
Net Negative Salvage				
Accum. Def. Income Taxes	(42,124)	(41,564)	(39,774)	(39,807)
Accum. Invest. Tax Credits	(3,583)	(3,074)	(2,229)	(2,229)
Customer Advances	(309)	(509)	(10)	(10)
Average Rate Base	$134,869	$133,667	$126,800	$128,902

5. The parties disputed the following issues:

- The return on common equity (ROE) MDU should be allowed. MDU proposes an ROE of 12.75%. Staff recommends an ROE of 11.7%.
- The overall cost of long-term debt. MDU proposes a weighted cost of 9.22% whereas staff advocates a weighted cost of 8.62%.
- The appropriate level of sales for resale margins. MDU proposes using 2001 sales levels combined with futures prices. Staff advocates using a 3-year historical average.
- The appropriate level of administrative and general expenses. MDU proposes a 12.3% increase compared to 2001 levels. Staff proposes a 4.6% reduction compared to 2001 levels.

Return on Common Equity

6. MDU's witness, Steven Gaske, argued that a return on equity of 12.75% is a fair and reasonable return to MDU's stockholders using a Discounted Cash Flow (DCF) calculation.

7. Staff's witness, Charles King, argued that a return on equity of 11.7% is a fair and reasonable return to MDU's stockholders using a DCF calculation.

8. During cross-examination, Gaske reviewed the annual survey of returns on equity granted by other state agencies as reported in the Public Utilities Reports for the year ended September 30, 2001. After reviewing the reports, Gaske noted that of the 45 companies listed, eleven companies were granted returns on equity higher than 11.7% and only three companies were granted returns on equity that were equal to or higher than 12.75%.

9. There were other differences in opinion but the primary areas of disagreement resulting in different recommended rates of return on common equity include:

- Flotation costs.
- Comparable companies.

10. Gaske argued strenuously about the value of using .625 rather than .5 for the dividend growth rate contained in the DCF formula. Both Gaske and King agreed that the difference was immaterial to the ROE calculation.

Flotation Costs

11. Flotation costs are the costs associated with issuing new common equity capital and make up approximately 58 basis points of difference between MDU and staff's position (Tr. p. 199). Eliminating the flotation cost from Gaske's calculation reduces his recommended return on equity of 12.75% to 12.17%, which is only 7 basis points different than King's electric only DCF returns of 12.1%.

12. Staff's position included a review of floatation costs actually incurred during the past five years. King found that the actual costs were immaterial and lost in the rounding when applied to the return required on common equity. As a result, staff did not include any flotation costs in its return on equity calculation.

13. Rather than using actual expenditures, MDU's witness Gaske argued for the inclusion of a theoretical cost of issuing common equity based on a sampling of electric companies during 1996-2000. Gaske's assumed flotation cost of 4.75% for new equity is then used to inflate the estimated return on equity. Essentially, Gaske's position includes enough flotation costs that MDU could reissue all of its common equity annually at the expense of ratepayers.

14. Gaske argued that the courts have had fundamental tests requiring that rates must be sufficient to attract capital in reasonable terms (Tr. p. 173). Yet, under cross-examination, Gaske could not provide any data supporting the notion that disallowing flotation costs would hinder the issuance of stock (Tr. p 209). To the contrary, Gaske agreed that most regulatory commissions do not allow flotation costs (Tr. p. 210).

15. Staff's witness Diller indicated that an average rate base has been declining since MDU's last 1986 test year. . Therefore, MDU's North Dakota electric operation

requires little or no common stock issuances. We agree with staff's position that flotation costs be disallowed.

Comparable Companies

16. Staff's witness King used a DCF analysis to estimate the cost of common equity. Based on certain criteria, King identified 8 comparable combination (gas and electric) utility companies' dividends and growth estimates for estimating the return required on MDU's common equity. King used a "interest rate risk premium" check to test his DCF conclusions for reasonableness.

17. Using a different set of criteria, MDU's witness Gaske utilized 12 companies including both electric only and combination companies for his DCF analysis. The different criteria resulted in Gaske discarding four combination companies identified by King and adding others. Gaske used a risk premium approach known as the Ibbotson & Singfield study and also the "alternative equity investment approach" to test his DCF conclusions for reasonableness.

18. Much discussion ensued as to which group provides the best estimate for MDU's cost of common equity capital. Essentially, staff argued that the comparison companies should be comprised of combination gas and electric companies because MDU is a combination gas and electric utility company. Gaske argued that because this proceeding is about MDU's electric operations, the comparison group should also include electric only companies.

19. Montana-Dakota Utilities Co. is a division of Montana-Dakota Resources Group, Inc. As such, any common stock issuance or dividend paid is done so by Montana-Dakota Resources Group, Inc., a combination gas and electric company.

20. We find that staff's proposed return on equity of 11.7% is a fair and reasonable return on equity to MDU's stockholders.

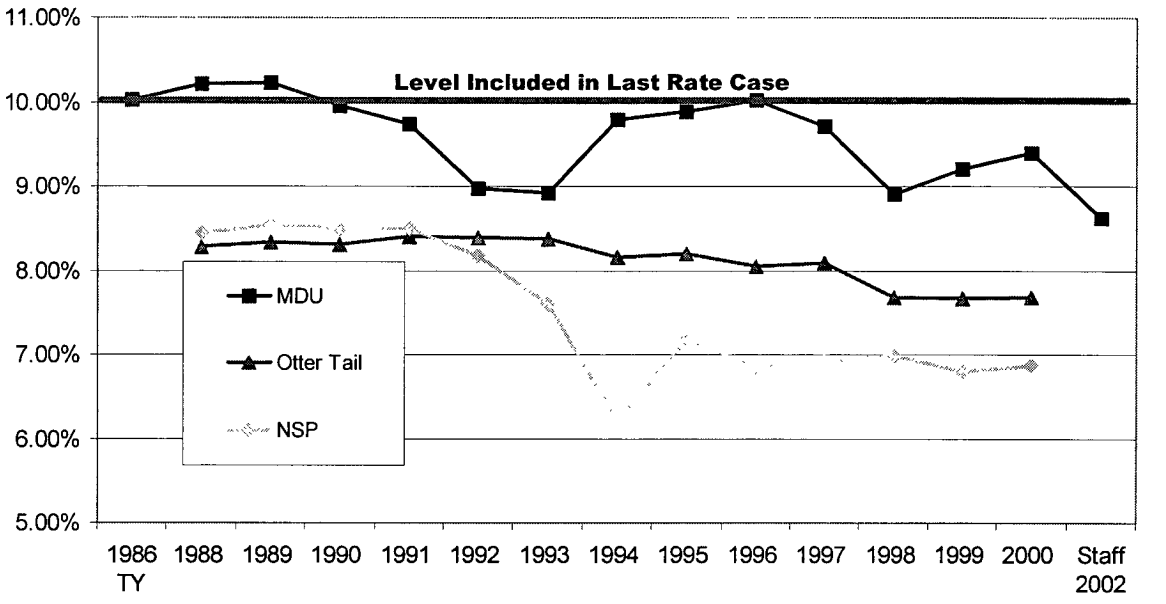
Weighted Cost of Long-Term Debt

21. Diller testified that MDU's reported cost of debt since 1988 remains significantly higher than the cost reported by the other two investor owned electric companies operating in North Dakota.

22. MDU's witness Gaske suggests in his surrebuttal testimony (Ex. 7 p.3) that differences in the cost of debt are due to timing of financing needs and therefore are often explained by the vintage of the debt obligations.

23. For 13 years, little progress has been made by MDU to bring its costs down to a level competitive with the other investor owned electric companies operating in North Dakota. The cost of debt as reported by the investor owned electric companies and included in Diller's testimony follows:

Cost of Debt Comparison



24. According to Diller, a one-percentage point reduction in weighted cost of debt lowers the annual revenue requirements from MDU's North Dakota customers by about $700,000. (Ex. 1 p. 20)

25. Staff argued for an accounting-based cost of debt calculation through its witness, King. King recommended that debt issuance and redemption costs be amortized over the life of the debt issues, which results in MDU recovering all of its costs. According to King, the Commission utilized an accounting-based cost of debt calculation in Northern States Power Company's last rate case application. Using an accounting-based cost, staff argued that MDU's cost of debt is 8.62%.

26. MDU argued for a "yield-to-maturity" cost of debt calculation. Gaske argued that the yield to maturity calculation gives consideration to the time value of money. Accordingly, the yield to maturity calculation results in a higher cost of debt or 9.22%.

27. The time value of money has not been considered with respect to other expenses included in the test year. Neither party presented any evidence regarding the allowance of cash working capital. Diller testified in his direct testimony that cash working capital is a calculated level of cash needed to pay ongoing expenses and that because revenues are often collected in advance of expenses, it can be a source of cost free capital. Diller's direct testimony states that the Commission's practice with MDU has been to disallow cash working capital absent a lead-lag study. His testimony

states that past Commission decisions have resulted in reducing rate bases of Otter Tail Power Company and Northern States Power Company for cash working capital and that its inclusion typically has benefited North Dakota ratepayers in other cases. We find that absent a lead-lag study, it is unwarranted and unfair to include the time value of money for issuance and redemption costs.

Cost of Capital Summary

28. Advocacy staff through its witness King, presented a capitalization structure and cost of preferred equity for this proceeding. Through its testimony, MDU adopted King's capitalization structure and cost of preferred equity.

29. King argued for an overall cost of capital of 9.92%, as follows:

	Staff		
	Capital		Weighted
Description	Ratio	Cost	Cost
Debt	45.90%	8.62%	3.96%
Preferred Stock	5.23%	4.63%	0.24%
Equity	48.87%	11.70%	5.72%
Total	100.00%		9.92%

30. We agree with staff's cost of capital.

Sales for Resale Margins

31. Staff argued for using an average of sales for resale margins during the past three years for a normalized level of $11,695,641 on a total company basis. Diller's resale settlement calculation, offered at the hearing, shows that staff has reduced 2001 sales for resale margins by $2.8 million on a North Dakota basis for the 2002 test year.

32. MDU argued for using 2001 sales volumes but splits the sales into either off-peak or on-peak sales. The margins are then calculated by multiplying the off-peak sales by an estimated price and the on-peak sales by futures prices quoted by the NYMEX Cinergy Hub.

33. Staff's method of normalizing sales for resale margins is based on actual transactions that have occurred during the past 3 years and then averaged for a proxy of expected margins in the future.

34. Staff's approach of using a three-year average gives consideration to the long time spans that typically occur between rate cases whereas MDU's approach focuses on the current market prices of the day. Under cross-examination, Diller asserted that

this proceeding is not just about setting rates for the next 6 months but instead for 2002 and beyond. MDU's last rate increase application was filed in 1986.

35. Under cross-examination, Diller was asked about the use of a three-year average (Tr. p. 52) to which he responded that the selected period was arbitrary. Diller further stated that the Commission could use a different length of time for averaging past results. Diller's rebuttal attachment MRD-1 depicts sales margins that have been growing for the past six years.

36. Diller identified 28 factors affecting future resale margins from the testimony of MDU's ten witnesses. One of the factors listed by Diller includes "new generation capacity." If price is determined by supply and demand principles discussed in this case, new electric supplies to meet new demand are critical to the long-term pricing of electricity. According to MDU's representation, the Mid-American Power Pool (MAPP) forecasts excess capacity in the future. However, Exhibit 11 entered by Commissioner Wefald shows that the North American Electric Reliability Council suggests that the MAPP capacity is inadequate for the time period of 2001-2010. This indicates that the experts can't agree on the critical element of the supply side of the price equation, and therefore, to assume that everything has changed and supply is now plentiful would be a huge step of faith.

37. With respect to the demand side of the price equation, staff agreed that the economy is somewhat confused at the moment but argued that fixing sales margins for potentially the next 15 years based primarily on futures prices of the day is unreasonable. MDU, on the other hand, would have the Commission believe that the sky is falling.

38. Turning to MDU's margins calculation, MDU splits its calculation between off-peak and on-peak sales. Diller questioned the calculation in his rebuttal testimony (Ex. 2, p. 10) because the off-peak sales margins portion reflects a net loss contribution to earnings of $144,319. Blinsky responded in his surrebuttal testimony that it is not MDU's common practice to sell below the incremental cost of fuel. He further asserted that his calculation uses average fuel costs and that during off-peak periods the off-system sales typically come from a specific unit. The inference being that MDU's off-peak margins are understated and the on-peak margins are overstated but, as a whole, the calculation is fair.

39. Diller stated in his rebuttal testimony (Ex. 2, p. 11) that staff requested source data for Blinsky's off-peak prices. According to Diller's testimony, MDU replied that off-peak prices are estimates based on recent experience. Diller continued in his rebuttal testimony that without the source data and some historical perspective, staff is unable to conclude anything from MDU's sales for resale margins calculation. We find that no evidence has been offered through direct, surrebuttal or through oral testimony to support MDU's sales price estimate for off-peak sales. Accordingly, MDU's off-peak margins portion of the calculation is suspect and baseless.

40. After cross-examination, MDU witness, Donald Ball, agreed to provide Late Filed Exhibit No. 16 showing the off-peak prices for MAPP for the past four years. We find that MDU's estimates for off-peak margins prices appear to be understated in comparison to the actual MAPP prices.

41. The remaining on-peak margins are calculated by multiplying 2001 sales volumes by the futures prices listed by NYMEX on a particular day. Diller testified that the futures prices may be pretty accurate a few months out but that the further out you go the less accurate futures are going to be as far as what actual prices may end up being. Gaske testified that the futures prices are the best estimate of what electricity will cost in the future and that the futures prices consider all the factors that affect the price of electricity.

42. We find that futures prices is one of the tools that may be used to estimate the future cost of electricity, but it is only one of several tools that may and should be employed. Both staff and MDU pointed out numerous factors that may affect the future price of electricity. We agree with staff that a long-term view of future margin levels should be taken and that a 3-year average for this proceeding is reasonable.

Administrative and General Expenses

43. The administrative and general (A&G) expense category includes a number of accounts including salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, regulatory Commission expenses, general advertising, miscellaneous general, rents and the maintenance of general plant.

44. Staff presented evidence at the hearing in its PowerPoint presentation that MDU's A&G expenses had been declining since 1996 until the year ended 2001. The company reported a 12.4% increase in A&G expenses in 2001 and MDU now argues in this case that it needs another 12.3% increase for 2002.

45. Staff argued at the hearing that MDU's surrebuttal testimony does not provide an analytical approach to quantifying future estimated costs and therefore the A&G expense increase sponsored by MDU should be rejected.

46. Staff noted a significant increase in the salaries account of A&G expenses. According to Diller's testimony, no exception was taken to the expense level as staff assumed that the difference was due to different levels of salary capitalization from one year to the next. Under cross-examination, Ball was not sure why A&G salaries increased so much but thought it had to due with the capitalization differences as well. Through cross-examination, Ball agreed to research the difference and file Late Filed Exhibit No. 19. Late Filed Exhibit No. 19 discloses that most of the difference resulted from the payment of higher bonuses and commissions ($635,765 on a total electric company basis). Staff did not make an adjustment to salaries expense, as this

information was not known until after the hearing. The bonus and commission increase from $581,509 to $1,217,274 appears unreasonable.

47. Staff identified three general areas of concern with respect to A&G expenses including MDU's projection of office supplies expense, insurance expense and pensions and benefits.

Office Supplies Expense

48. The office supplies expense category includes such expenditures as automobile services, bank charges, books and subscriptions, building service, communications, office equipment, computer infrastructure, membership fees, office supplies, legal department expenses, postage and printing, travel and incidental expenses and corporate aircraft expenses.

49. In rebuttal testimony, Diller shows that annual office supplies expense normally runs around $1.8 million to $2.1 million but that actual expenditures for 2001 were reported to be $2.9 million. MDU argued that the new level established in 2001 is a reasonable expense level for 2002. On the other hand, staff inflated actual 2000 expenses by 5% to include a more normal level of $2.228 million for the test year.

50. Staff's position is that the types of expenditures included in office supplies expense are controllable expenditures. Staff noted that MDU is not all that different from the Commission. Diller stated, for example, that there are some years when the commission spends a lot of money on computer software and hardware upgrades, but there are also years when that is not the case because of budgetary constraints. To assume that one extremely high cost year is representative of future expense levels is unreasonable. Further, Diller compared the Commission in this proceeding to the legislature when it appropriates a certain level of funds to the Commission. Controllable costs can be controlled and the Commission should order a reasonable and normal level of office supplies expense.

51. Staff argued that MDU did not use an analytical approach to quantifying future estimated costs. Instead, MDU relied on the expenditure level of one high cost year (2001). Staff highlighted its concerns by pointing out that MDU explained that a substantial part of the increase is attributable to its new corporate aircraft. Yet, no attempt was made or has been made to quantify savings attributable to acquiring the aircraft.

52. Through cross-examination, Ball agreed to submit Late Filed Exhibit No. 17 depicting office supply expenses by various accounts for Commission consideration.

Insurance Expense

53. MDU argued for an increase in North Dakota insurance expense of $155,383 to reflect higher 2002 premiums. MDU argued that the events on September 11 resulted

in increased insurance costs and that the higher costs are reflected in the 2002 premiums.

54. Staff argued that MDU's testimony did not include a review of all insurance expenditures and that it is inconclusive.

55. As a result of staff's position and cross-examination, Ball agreed to submit Late Filed Exhibit No. 18 to show which premiums are causing the increase in expenditures for 2002.

Pensions & Benefits

56. Staff identified two areas of concern regarding MDU's proposed cost of pensions and benefits, as follows:

- Pension Expense and Post Retirement Expense (FAS 106)
- Supplemental Income Security Plan (SISP)

Pension and Post Retirement Expense

57 MDU's witness Ball argued for an adjustment to pension expense and post retirement expense in his direct testimony. In rebuttal testimony, staff argued that it asked for source data related to the adjustments but that the actuarial information was not provided. In surrebuttal testimony, MDU offered to let Diller review the actuarial study on a confidential basis.

58. Diller concluded at the hearing that both the pension expense and post retirement expense adjustments argued for by MDU does not include a review of all employee pension and benefits expenditures and is inconclusive. Staff made no adjustment to 2001 expense levels.

59. Ball argued that MDU does not have any knowledge of other known changes to pension and post retirement expenses other than the 2002 actuarial studies. Ball argued that the increase is attributable to low investment returns in recent years and the use of a lower discount rate for future years. He further argued that the increases for 2002 are real and currently being booked and that more increases are expected through 2005. MDU's case includes an upward adjustment to 2001 expense of $179,000 for pension expense and $62,000 for post retirement expenses.

Supplemental Security Income Plan (SISP)

60. MDU argued for the inclusion of expenses associated with SISP whereas staff argued strenuously against its inclusion in ratemaking expense.

61. MDU included the SISP adjustment in its direct testimony. In direct testimony, Ball argued that the plan provides a supplemental pension benefit to key employees.

Ball further argued that the benefit is necessary to attract and retain high quality staff in a number of key positions within the company.

62. Diller argued through rebuttal testimony that while the plan has been in effect since 1982, the company has never sought rate recovery in any subsequent electric or gas rate case.

63. Diller argued in his rebuttal testimony that MDU's plan lacks symmetry and pointed out that the SISP benefits are heavily weighted in favor of the high-end salaried employees participating in the plan. For instance, an employee making $50,000 a year would receive a monthly SISP benefit of $1,330 compared to a monthly benefit of $30,000 for the employee making $600,000 a year. In the case of the low-end employee, the monthly benefit calculates to be 2.66% of annual salary compared to the high-end employee who would receive a monthly benefit of 5% of annual salary. Diller noted that only 27 employees of MDU's gas and electric employees are considered to be key employees.

64. MDU's witness Richard Espeland argued in surrebuttal testimony that defined benefit and pension plans and social security are limited as to the maximum benefits a company can pay to its employees. Therefore, the more traditional plans benefit the low paid employees more than the high paid employees on a percentage of income basis. Espeland argued that the SISP enables MDU's key employees to benefit on a more comparable basis when considering benefits as a percentage of income.

65. Espeland indicated that the key employees participating in the plan include officers, directors and senior managers who have the vision to adequately plan for the future and implement appropriate strategies.

66. At the hearing, Diller responded further to the idea of including SISP in ratemaking expense. Diller characterized SISP as a double pension for MDU's few key employees and talked about the Enron debacle and the payments it made to key employees. Diller observed that one of the Congressmen in the Enron hearings stated that the payments to key employees looked like management taking care of itself. Diller observed that Enron provided a warning to all of us, especially managers of companies.

67. Diller opposed spending a million dollars a year for the benefit of a few employees. In addition to SISP, these key employees are paid very well (minimum of $75,000 to $80,000 per year according to Espeland) and participate in all the other benefits offered to regular employees such as health insurance, life insurance, 401k participation, profit sharing plans, incentive plants, defined benefit plans, social security and discounted gas and electric service for those living in MDU's service territory.

68. At the hearing, Espeland testified that the plan includes 27 active participants, but that there are also 34 inactive vested participants for a total of 61 current and past employees. Of these, Espeland testified that only 20 are in a pay status. Espeland

further testified that prior employees were not fully funded and that the company has only set aside 20% to 30% of the total liability.

Net Regulated Income

69. Diller presented a historical summary of reported earnings and staff's recommended test year earnings, as follows:

	(Thousands)				
	Reported by MDU				
Description	1999	2000	2001	Adjustments	Test Year
Sales for Resale	$13,265	$15,034	$17,687	($2,800)	$14,887
All Other Revenues	80,657	81,929	84,415	0	84,415
Total Revenues	$93,922	$96,963	$102,102	($2,800)	$99,302
Production Expense	$37,160	$38,365	$40,671	($765)	$39,906
Transmission Expense	3,667	3,567	3,915	370	4,285
Distribution Expense	4,586	4,660	5,010	0	5,010
Customer Accounts	2,162	2,113	2,233	0	2,233
Customer Service & Info.	96	105	113	0	113
Sales Expense	258	269	281	0	281
Administration & General	8,303	8,154	8,968	(414)	8,554
Total O & M Expense	$56,232	$57,233	$61,191	($809)	$60,382
Depreciation	$11,436	$11,803	$11,955	$77	$12,032
Taxes Other Than Income	$3,936	$3,811	$4,019	$0	$4,019
Income Tax Expense	$6,319	$6,750	$7,955	($852)	$7,103
Net Regulated Income	$15,999	$17,366	$16,982	($1,216)	$15,766
Income Tax Calculation:					
Net Income Before Taxes	$22,318	$24,116	$24,937		$22,869
Less Interest Deduction:					
Rate Base	$134,869	$133,667	$126,800		$128,902
Weighted Cost of Debt	4.93%	4.74%	3.96%		3.96%
Calculated Interest Deduction	$6,644	$6,332	$5,017		$5,101
Other Tax Adjustments	$281	($743)	$163		$163
Taxable Income	$15,955	$17,041	$20,083		$17,931
Combined Tax Rate	39.61%	39.61%	39.61%		39.61%
Income Tax Expense	$6,319	$6,750	$7,955		$7,103

70. Staff concluded its direct oral testimony with a calculation of MDU's annual excess earnings, as follows:

	(Thousands)			
	Reported			
Description	1999	2000	2001	Test Year
Average Rate Base	$134,869	$133,667	$126,800	$128,902
ROR Required (11.7% ROE)	10.07%	10.20%	9.92%	9.92%
Return Required	$13,575	$13,627	$12,574	$12,783
Return Earned	$15,999	$17,366	$16,982	$15,766
Return (Excess)	($2,424)	($3,738)	($4,408)	($2,984)
Tax Factor	1.656	1.656	1.656	1.656
Revenue (Excess)	($4,014)	($6,191)	($7,300)	($4,941)

Conclusions of Law

1. The Commission has jurisdiction over the parties and the subject matter in this proceeding.

2. MDU is entitled to a rate level adequate to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.

3. MDU's existing electric rates yield excess revenues of $4.941 million per year.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders:

1. MDU shall file revised tariff sheets, reflecting an across the board rate reduction to produce a total annual rate revenue decrease of $4.941 million.

2. The rate reduction is to be effective within 30 days of this order.

PUBLIC SERVICE COMMISSION

Anthony T. Clark **Commissioner**	**Susan E. Wefald** **President**	**Leo M. Reinbold** **Commissioner**

Public Service Commission
State of North Dakota

COMMISSIONERS

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Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

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March 28, 2002

Mr. Charles King
Snavely King Majoros O'Connor & Lee, Inc.
Economic and Management Consultants
1220 L Street NW Suite 410
Washington DC 20005

Re: Contract No. PU-427-01
Consulting Services MDU Rate-of-Return Study

Dear Mr. King:

Our records indicate that all services required under the terms of the contract for professional services, Contract No. PU-427-01, have been performed. Accordingly, we are preparing to close out the contract. If you have any outstanding claims for service against this contract, please notify us immediately.

Once the contract is closed the Commission will consider all claims for services to have been paid.

If you have any questions, please call me at 701-328-4079.

Sincerely,

Mike Diller

Mike Diller
Director, Accounting Division

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Letter to consulting service re closing out consulting contract
by Public Service Commission by Mike Diller

03/28/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

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03/13/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

83 **PU-399-01-186** Pages: 225

Original - Transcript of Hearing Volume II
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03/13/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

84 **PU-399-01-186** Pages: 67

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85 **PU-399-01-186** Pages: 57

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EXHIBIT
15
Date 2/26/02

Case No. PU-399-01-186
Exhibit No.___(RJS-8)

Table 1
Completed and Sited New Power Plants in MAPP
2001-2020

					Siting Status		Cumulative		
On-line	Region	Name	Location	Summer MW	Completed MW	Sited MW	Completed MW	Sited MW	Cumulative Completed and Sited MW
2001	UMV	Gas Turbine	Mower Cty, MN	310	310		310	-	310
2001	UMV	Utilities Plus	Windom	2	2		312	-	312
2001	ITWG	Earlville	Earlville, IA	2	2		314	-	314
2001	ITWG	Lenox	Lenox, IA	2	2		316	-	316
2001	UMV	Chaska (MN River)	Chaska, MN	45	45		361	-	361
2001	ITWG	DAEC (Uprate)	Cedar Rapids, IA	65	65		426	-	426
2001	Nebraska	Rokeby CT Unit 3	Lincoln, NE	93	93		519	-	519
2001	UMV	Diesel	Forest City, IA	6	6		525	-	525
2001	UMV	Diesel	Lake Mills, IA	6	6		531	-	531
2001	UMV	Diesel	Fennimore, WI	6	6		537	-	537
2001	UMV	Elk Mound	Eau Claire, WI	84	84		621	-	621
2001	UMV	Lakefield Junction	Martin County, MN	550	550		1,171	-	1,171
2001	Nebraska	Aries Plant	Pleasant Hill, MO	585	585		1,756	-	1,756
2001	UMV	Willmar	Wilmar	12	12		1,768	-	1,768
2001	ITWG	Brooklyn	Brooklyn, IA	2	2		1,770	-	1,770
2001	ITWG	Greenfield	Greenfield, IA	2	2		1,772	-	1,772
2001	ITWG	Winterset	Winterset, IA	2	2		1,774	-	1,774
2001	UMV	New Ulm	New Ulm	10		10	1,774	10	1,784
2001	UMV	Grantsburg	Grantsburg, WI	6		6	1,774	16	1,790
2001	UMV	Utilities Plus	Sleepy Eye	2		2	1,774	18	1,792
2001	UMV	Utilities Plus	Sleepy Eye	2		2	1,774	20	1,794
2001	UMV	Peaking/Diesel	Westbrook MN	3		3	1,774	23	1,797
2001	UMV	Utilities Plus	Madelia	3		3	1,774	26	1,800
2001	UMV	New Ulm	New Ulm	2		2	1,774	28	1,802
2001	UMV	Utilities Plus	Fairfax	2		2	1,774	30	1,804
2001	ITWG	Harlan	Harlan, IA	3		3	1,774	33	1,807
2001	UMV	Chaska (MN River)	Chaska, MN	5		5	1,774	37	1,811
2001	UMV	Utilities Plus	Delano	12		12	1,774	49	1,823
2001	UMV	Univ MN Steam Plant	Minneapolis, MN	14		14	1,774	63	1,837
2001	Nebraska	GCW Wind Farm	Montezuma, KS	110		110	1,774	173	1,947

Table 1, Completed & Sited New Power Plants in MAPP
by Montana-D Utilities Co., a Division of MDU R
Exhibit # 15
02/26/2002 Cc: Comm Legal Illona, Pat, Jerry Mike

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Case No. PU-399-01-186
Exhibit No.___(RJS-8)

Table 1
Completed and Sited New Power Plants in MAPP
2001-2020

					Siting Status		Cumulative		
On-line	Region	Name	Location	Summer MW	Completed MW	Sited MW	Completed MW	Sited MW	Cumulative Completed and Sited MW
2001	UMV	Wind	Buffalo Ridge, MN	7		7	1,774	180	1,954
2002	Nebraska	Alliance Diesel	Alliance, NE	5		5	1,774	186	1,960
2002	RRV	Gas Turbine	Brandon, AB	230		230	1,774	416	2,190
2002	UMV	Hurley	Hurley, WI	55		55	1,774	471	2,245
2002	UMV	Gas Turbine	Mower Cty, MN	124		124	1,774	595	2,369
2002	UMV	Gingles	Ashland, WI	55		55	1,774	650	2,424
2002	RRV	Hillsboro Diesel	Hillsboro, ND	4		4	1,774	654	2,428
2002	UMV	Benson Diesel	Benson, MN	11		11	1,774	665	2,439
2002	UMV	Peaking/Diesel	Worthington, MN	18		18	1,774	683	2,457
2002	RRV	Lindroc (Biomass II)	Intl Falls, MN	25		25	1,774	708	2,482
2002	UMV	Cascade Creek, CT	Rochester, MN	40		40	1,774	748	2,522
2002	UMV	Coal Creek Upgrade	Coal Creek Station, ND	72		72	1,774	820	2,594
2002	Nebraska	DCLFG Units 1-4	Bennington, NE	3		3	1,774	823	2,597
2002	ITWG	Wilton	Wilton, IA	4		4	1,774	827	2,601
2002	ITWG	Pella	Pella, IA	24		24	1,774	851	2,625
2002	UMV	West Faribault	Faribault, MN	110		110	1,774	961	2,735
2002	UMV	Black Dog CC 5	Black Dog	290		290	1,774	1,251	3,025
2002	UMV	Diesel	Redwood Falls, MN	6		6	1,774	1,257	3,031
2002	UMV	St. Boni	St. Bonifacius, MN	16		16	1,774	1,273	3,047
2002	UMV	Chanarambie Power Partners	Buffalo Ridge, MN	80		80	1,774	1,353	3,127
2002	RRV	Fibro-Minn	Benson, MN	50		50	1,774	1,403	3,177
2003	UMV	Utilities Plus	Granite Falls	3		3	1,774	1,406	3,180
2003	UMV	Utilities Plus	Sleepy Eye	2		2	1,774	1,408	3,182
2003	MB	Peaking/Diesel	Pierre, SD	12		12	1,774	1,420	3,194
2003	UMV	St Paul District Energy	St. Paul, MN	25		25	1,774	1,445	3,219
2003	Nebraska	Cass County Unit 1	Plattsmouth, NE	160		160	1,774	1,605	3,379
2003	Nebraska	Fremont, CT	Fremont, NE	50		50	1,774	1,655	3,429
2003	ITWG	Des Moines EC	Des Moines, IA	178		178	1,774	1,833	3,607
2003	ITWG	Des Moines EC	Des Moines, IA	178		178	1,774	2,011	3,785
2003	Nebraska	Paola CTs	Paola, KS	231		231	1,774	2,242	4,016

Table 1
Completed and Sited New Power Plants in MAPP
2001-2020

					Siting Status		Cumulative		
On-line	Region	Name	Location	Summer MW	Completed MW	Sited MW	Completed MW	Sited MW	Cumulative Completed and Sited MW
2003	Nebraska	Cass County Unit 2	Plattsmouth, NE	160		160	1,774	2,402	4,176
2003	Nebraska	Salt Valley CC 1-3	Lincoln, NE	117		117	1,774	2,519	4,293
2003	UMV	Peaking	Superior, MN	160		160	1,774	2,679	4,453
2004	UMV	Utilities Plus	Glencoe	5		5	1,774	2,684	4,458
2004	RRV	Gas Turbine	Glendive, MT	33		33	1,774	2,717	4,491
2004	Nebraska	Salt Valley CC 4	Lincoln, NE	45		45	1,774	2,762	4,536
2004	UMV	EPS BeckPower	St. Peter, MN	50		50	1,774	2,812	4,586
2004	Nebraska	Grand Island CTs	Grand Island, NE	80		80	1,774	2,892	4,666
2004	MB	Watertown	Watertown, SD	150		150	1,774	3,042	4,816
2004	ITWG	Wisdom CT	Spencer, IA	80		80	1,774	3,122	4,896
2004	ITWG	Entergy IPP	Adair Cty, IA	171		171	1,774	3,293	5,067
2004	ITWG	Entergy IPP	Adair Cty, IA	171		171	1,774	3,464	5,238
2004	ITWG	Entergy IPP	Adair Cty, IA	289		289	1,774	3,753	5,527
2005	ITWG	Des Moines EC	Des Moines, IA	182		182	1,774	3,935	5,709
2005	Nebraska	Beatrice CC	Beatrice, NE	229		229	1,774	4,164	5,938
2005	Nebraska	Sand Sage 1	Holcomb, KS	600		600	1,774	4,764	6,538
2006	ITWG	Denison	Denison, IA	50		50	1,774	4,814	6,588
2006	RRV	Moorhead #2	Moorhead, MN	50		50	1,774	4,864	6,638
2007	RRV	Gas Turbine	Miles City, MT	66		66	1,774	4,930	6,704
2007	Nebraska	Hastings EC #2	Hastings, NE	200		200	1,774	5,130	6,904
2008	RRV	LV21	Gascoyne, ND	500		500	1,774	5,630	7,404
2009	Nebraska	Cass Cty #3	Plattsmouth, NE	160		160	1,774	5,790	7,564
2010	RRV	Moorhead #3	Moorhead, MN	50		50	1,774	5,840	7,614

Source: 2001 Update to the 2000 Regional Plan: 2000 through 2009, Mid-Continent Area Power Pool Transmission Planning Subcommitte, November 30, 2001

Case No. PU-399-01-186
Exhibit No.___(RJS-9)

Table 1

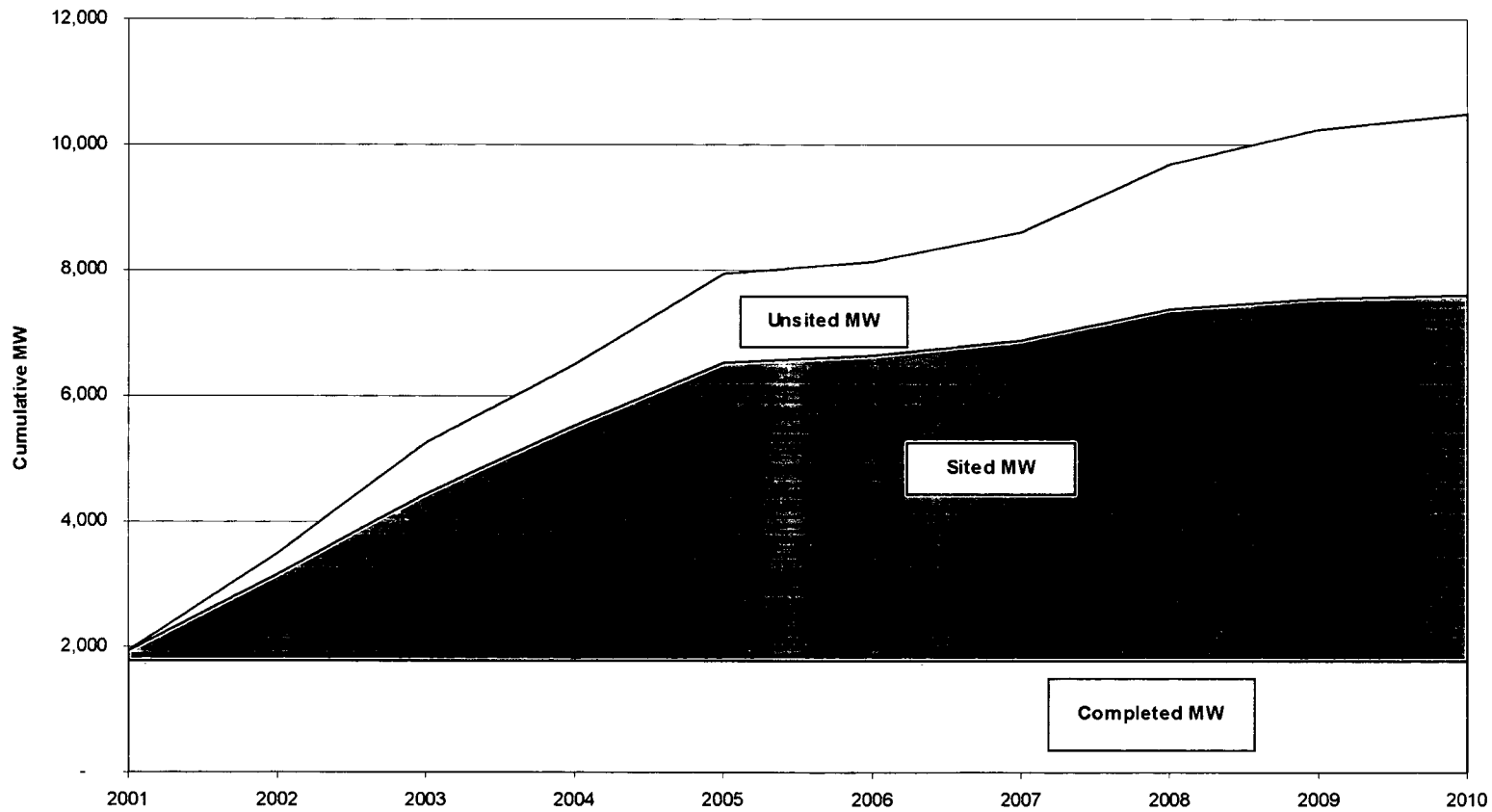
New Power Plants Proposed in MAPP but without Identified Sites

2001-2020

On-line	Region	Name	Location	Summer MW	Unsited MW	Cumulative Unsited MW
2002	UMV	Combined Cycle	Unknown	325	325	325
2003	UMV	Various RFPs by Xcel	Competitive Bid	200	200	525
2003	UMV	Combined Cycle	Unknown	215	215	740
2003	UMV	Gas Turbine	Unknown	49	49	789
2004	UMV	Various RFPs by Xcel	Competitive Bid	200	200	989
2005	UMV	Various RFPs by Xcel	Competitive Bid	200	200	1,189
2005	UMV	Combined Cycle	Unknown	215	215	1,404
2006	UMV	Various RFPs by Xcel	Competitive Bid	100	100	1,504
2007	UMV	Various RFPs by Xcel	Competitive Bid	200	200	1,704
2008	UMV	Various RFPs by Xcel	Competitive Bid	600	600	2,304
2009	UMV	Various RFPs by Xcel	Competitive Bid	400	400	2,704
2010	UMV	Various RFPs by Xcel	Competitive Bid	200	200	2,904

Source: *2001 Update to the 2000 Regional Plan: 2000 through 2009, Mid-Continent Area Power Pool Transmission Planning Subcommitte, November 30, 2001*

Figure 1
Proposed New Generation in the MAPP Region
2001-2010



Source: *2001 Update to the 2000 Regional Plan: 2000 through 2009, Mid-Continent Area Power Pool Transmission Planning Subcommitte, November 30, 2001*

Table 1
Comparison of Proposed New Generation and Projected Demand Growth
2001-2010

Year	Annual Forecast Net Internal Demand (MW)	Annual Change in Demand (MW)	Annual Completed and Sited Capacity Additions (MW)	Proposed Capacity Additions Above(Below Load Increases (MW)
2001	27,788		1,948	
2002	28,229	441	1,223	782
2003	28,756	527	1,276	749
2004	29,280	524	1,074	550
2005	29,775	495	1,011	516
2006	30,294	519	100	(419)
2007	30,892	598	266	(332)
2008	31,474	582	500	(82)
2009	32,099	625	160	(465)
2010	32,925	826	50	(776)

Note: *New Additions from 2001 Update to the 2000 Regional Plan: 2000 through 2009*
Mid-Continent Area Power Pool, Transmission Planning Subcommitte, November 30, 2001

Demand forecast from MAPP EI-411, July 1, 2002

ity operations of Montana Power are less risky now that it has restructured and divested its generation assets. As a consequence, the commission reduced the equity ratio used in determining cost of capital for rate-making purposes from 44.12% common equity to 43%. In setting rates for the gas utility operations of Montana Power, the commission found that the gas utility faces less risk following the deregulation of natural gas supply and the implementation of a natural gas cost tracker that allows changes in commodity costs to be passed through to ratepayers without a full rate case. The authorized ROE for both the electric and gas utility was set at 10.75% — down from the 11% ROE last authorized for the electric utility and the 11.25% ROE awarded when rates were last set for the gas utility.

Although the number of "full-blown" rate cases appears to have diminished in recent years — the result of low inflation and the trend toward price regulation — the process of determining authorized ROE for energy utilities continues to dismay state regulators. The Oregon Public Utility Commission brought attention to this point while setting rates for Portland General Electric Company following an unprecedented rise in the cost of wholesale power. Noting that a large part of the rate hearing was devoted to argument over the proper ROE, the commission complained that given the inherent complexity of the issue it "may be impossible to devise a method to make the process of determining a reasonable ROE an agreeable one." Nevertheless, in an attempt to make the process less burdensome, the commission offered a generalized set of guidelines for witnesses to follow in presenting cost of capital recommendations in future rate cases. *Re Portland General Electric Co.*, UE 115, Order No. 01-777, 212 PUR4th 1 (Or.P.U.C.2001).

Compiled by Phillip S. Cross, a legal editor for Public Utilities Reports, Inc.

Public Utilities Reports
Advance Sheets

December 15, 2001

Index to Cases Reported appears on page x.

Authorized Rate of Return On Common Equity: An Annual Survey of Gas and Electric Rate Proceedings

Introduction

The following pages present the results of our latest annual survey of authorized rates of return on common equity (ROE) for state-regulated energy utilities. This year's survey covers orders issued by state regulatory commissions during the period October 1, 2000 through September 30, 2001. The survey reports the results of traditional, cost-of-service rate filings, as well as generic ROE proceedings, price regulation plans, and merger-related rate agreements. The reported ROE figures were obtained from a variety of sources, including rate analysts at state public utility commissions, rate department personnel at major, investor-owned electric and gas utilities, and directly from orders issued by state regulators. Explanatory footnotes are provided as necessary, and citations are given for orders published in *Public Utilities Reports, Fourth Series (PUR4th)*. Many of the unpublished orders are accessible through PURbase CD ROM, WESTLAW, and LEXIS.

A review of the rate orders included in the survey indicates that many state regulatory commissions continue to rely primarily on the results of discounted cash flow analyses in setting authorized ROE. However, other factors — e.g, general trends in interest rates, business risk, and regulatory risk — are often given considerable weight in ROE determinations.

Debate continues over the effect of electric industry restructuring and generation asset divestiture on risk, investor expectations, and required return. Similarly, regulators continue to consider whether the movement toward a competitive market model for the pricing of gas supply requires a reassessment of risks and required returns for natural gas local distribution companies. For example, in *Re Montana Power Co.*, 209 PUR4th 434 (Mont.P.S.C.2001), the state public service commission concluded that the electric util-

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
ARIZONA									
Xcel Energy - Black Mountain Gas Co.	Gas	63545	4/28/00	3/30/01	12/31/99	0.326	0.174	—	10.75[1]
CALIFORNIA									
Sierra Pacific Power Co.	Electric	D.00-12-062 *206 PUR4th 248*	5/8/00	12/21/00	12/31/01	NA	[.562]	11.60	10.80[2]
COLORADO									
Public Service Co. of Colorado dba Xcel Energy	Gas	00S-422G C01-231 *208 PUR4th 322*	7/17/00	3/15/01	12/31/99	39.8	14.2	11.25	11.25
CONNECTICUT									
Connecticut Natural Gas Corp.	Gas	99-09-03 *210 PUR4th 27*	2/9/00	5/9/01	6/30/99	NA[3]	NA[4]	10.8	10.8[5]
Southern Connecticut Gas Co.	Gas	99-04-18	7/15/99	1/28/00	12/31/99	21.4	.502	11.45	10.71

[1]Derived from approved settlement agreement authorizing revenue increase shown.
[2]ROE for electric distribution operations. Commission establishes automatic trigger mechanism for adjusting ROE based on changes in interest rates.
[3]Utility proposed incentive rate plan designed to match costs and efficiencies of recent merger.
[4]Approved rate plan includes four-year rate freeze at levels approved in *Re Connecticut Natural Gas Co.*, 201 PUR4th 225 (Conn.D.P.U. 2000).
[5]Excess earnings sharing begins with allocation to ratepayers of 75% of first 200 basis points above 10.8% allowed ROE.

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
FLORIDA									
Chesapeake Utilities Corp.	Gas	000108-GU	5/15/00	11/28/00	12/31/01	1.83	1.25	11.00	11.5
City Gas Co. of Florida	Gas	000768-GU *207 PUR4th 181*	8/25/00	2/5/01	9/30/01	7.18	5.13	11.3	11.5[6]
St. Joe Natural Gas Co.	Gas	001447-GU	12/15/00	6/8/01	12/31/01	.551	.327	11.0	11.5
HAWAII									
Hawaii Electric Light Co., Inc.	Electric	99-0207 Decision 18365 *207 PURth 117*	10/25/99	2/8/01	12/31/00	15.5	8.4	11.65	11.50[7]
IOWA									
United Cities Gas Co.	Gas	RPU-01-2	3/5/01	3/21/01	12/31/00	[.326]	[.326][8]	11.0	11.0

[6]Commission calculates ROE based on average of results of capital asset pricing and prospective risk premium models, as adjusted for financial risk associated with LDC's relatively small size and lower than average equity ratio.

[7]Includes adjustment of 50 basis points for additional risks due to utility's small size, high operating ratio, lower quality earnings, weak level of internally generated funds for construction, and substantial purchased power obligations.

[8]Settlement.

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
KANSAS									
UtiliCorp, Inc.	Electric	01-WPEE-473-RTS	12/8/00	9/15/01	6/30/00	14.2	3.8	10.55	10.91
Western Resources, Inc. dba KPL	Electric	01-WSRE-436-RTS[9] *212 PUR4th 517*	11/27/00	9/5/01	9/30/00	92.6	25.4	*	11.02
Western Resources, Inc. dba Kansas Gas & Electric Co.	Electric	01-WSRE-436-RTS[9] *212 PUR4th 517*	11/27/00	9/5/01	9/30/00	57.9	[41.0]	*	11.02
KENTUCKY									
Louisville Gas & Electric Co.	Gas	2000-080 *204 PUR4th 196*	3/30/00	9/27/00	12/31/99	26.377	20.193	12.5	11.25[10]
LOUISIANA									
CLECO Corp.	Electric	U-21496D[11]	12/15/00	8/8/01	9/30/00	NA	NA	12.25	12.25
MINNESOTA									
UtiliCorp United, Inc. dba Peoples Natural Gas Co.	Gas	G-007 011/GRL 00-951	5/12/00	5/11/01	NA	8.461	4.802	NA	11.71[12]
UtiliCorp United, Inc. dba Northern Minnesota Utilities	Gas	G-007 011/GRL 00-951	5/12/00	5/11/01	NA	1.385	0.422	NA	11.71[12]

*Settlement, no authorized ROE specified.

[9]Order modifies and clarifies *Re Western Resources, Inc.*, 211 PUR4th 8, in which the commission set interim rates for two affiliated electric utilities. Rates to be made permanent once effect of recent corporate reorganization on capital structure is demonstrated. Commission rules that it may apply an "interest synchronization adjustment" if high debt level threatens financial stability of operating utilities.

[10]Return revenue requirement determined by applying cost of capital to gas capitalization, rather than to test period rate base. Commission finds that use of "inflated" rate base figures would produce inaccurate estimate of utility income requirements.

[11]Proceeding to review utility earnings.

[12]Figure shown is stated in approved modified settlement agreement.

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
MISSISSIPPI									
Entergy Mississippi, Inc.	Electric	93-UA-301[13]	3/14/01	4/27/01	12/31/01	6.7	5.6	10.34	9.98
MONTANA									
Montana Power Co.	Electric	D.2000.8.113 *209 PUR4th 434*	8/11/00	5/9/01	12/31/99	38.5[14]	16.006[15]	11.0	10.75[16]
Montana Power Co.	Gas	D.2000.8.113 *209 PUR4th 434*	8/11/00	5/9/01	12/31/99	12.0[14]	4.268[15]	11.25	10.75[16]
NEW YORK									
Corning Natural Gas Corp.	Gas	00-G-0354	2/24/00	2/12/01	2/22/01[17]	.384	[.300]	NA	10.7
Niagara Mohawk Power Corp.	Gas	99-G-0336	3/11/99	7/27/00	10/31/00[17]	13.7	0	11.4	10.0
Orange & Rockland Utilities, Inc.	Gas	99-G-1695 *206 PUR4th 262*	12/3/99	11/20/00	11/1/00[17]	12[18]	18.071[19]	NA	10.6[20]
Rochester Gas & Electric Corp.	Gas	98-G-1589 *208 PURth 97*	1/25/01	2/28/01	7/1/00[17]	[2.806]	[2.806][21]	NA	11.0[22]

[13] Annual earnings review under formula rate plan.
[14] Amount requested includes adjustment allowed under optional year-end rate base filing rule.
[15] Approved increase shown replaces earlier interim awards.
[16] Capital structure and ROE adjusted to reflect reduced risk associated with divestiture of electric generating assets and deregulation of gas supply operations.
[17] Beginning of multi-year rate and restructuring plans designed to promote competition in gas market.
[18] Utility proposed increasing revenues by $12 million in year 2000, and also offered multiyear rate plan.
[19] Settlement in lieu of increase in base rates permits LDC to retain ratepayer credits and adjustment clause overcollections.
[20] Revenue requirement determined using base ROE shown. Settlement permits utility to retain earnings up to 11.1%. ROE.
[21] Decrease applied on levelized basis over a two-year period.
[22] Earnings in excess of 12.5% ROE to be used to offset deferred costs accumulated during rate period.

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
NORTH DAKOTA									
Northern States Power Co. dba Xcel Energy	Electric	PU-400-00-195	4/20/00	12/29/00	—	[0.3]	[0.3]	11.5	12.0[23]
Northern States Power Co. dba Xcel Energy	Gas	PU-400-00-521 211 PUR4th 44	10/9/00	6/27/01	12/31/00	1.4	0.5[24]	12.0	11.5
Otter Tail Power Co.	Electric	PU-401-00-36 *206 PUR4th 452*	1/31/00	12/29/00	1/1/01	—[25]	—[26]	NA	12.0[27]
Otter Tail Power Co.	Gas	PU-401-00-36 *206 PUR4th 452*	1/31/00	12/29/00	1/1/01	—[25]	—[26]	NA	12.0[27]
OREGON									
PacifiCorp	Electric	UE 111 Order No. 00-580	11/5/99	10/1/00	12/31/98	61.8	13.6	10.00	11.125[28]
PacifiCorp	Electric	UE 116 Order No. 01-787 *212 PUR4th 379*	11/1/00	9/7/01	12/31/01	160.8	64.4	11.125	10.75
Portland General Electric Co.	Electric	UE 115 Order No. 01-777 *212 PUR4th 1*	10/1/00	8/31/01	12/31/02	324.4	407.5[29]	11.60	10.50

[23]Rate application includes performance-based rate plan for five-year period 2001-2005. Allowed ROE varies around stated mid- point depending on performance results.

[24]Approved settlement agreement provides 1.2% increase in non- gas base rates. Test period cost of service reduced by $.125 million for savings resulting from merger of Northern States Power Co. and New Century Energies, Inc.

[25]Approved settlement initiates 5-year performance-based rate plan. Rates approved in 1999 earnings review case found just and reasonable as starting point for new rate plan.

[26]Performance-based rate plan includes price cap mechanism limiting rate adjustments based on comparable rates, inflation, and previous year earnings.

[27]Base line ROE for revenue sharing component of performance- based rate plan.

[28]Result of approved revenue stipulation.

[29]Increase reflects power costs updated subsequent to date of filing.

ANNUAL SURVEY OF ELECTRIC AND GAS UTILITIES

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
RHODE ISLAND									
Providence Gas Co.	Gas	2581 Order No. 16584 *209 PURth 519*	8/2/00	4/30/01	10/1/00[30]	NA	4.5[31]	10.9	10.7[32]
TEXAS									
Entergy Gulf States, Inc.	Electric	22356	3/31/00	5/25/01	12/31/02	NA[33]	NA	10.95	11.25[34]
VERMONT									
Central Vermont Public Service Corp.	Electric	6460 *211 PUR4th 53*	11/9/00	6/26/01	6/30/00	19	9.852[35]	11.00	11.00
Green Mountain Power Corp.	Electric	6107 *207 PUR4th 1*	5/8/98	1/23/01		20.8	19.79[35]	11.00	11.25
Vermont Gas Systems, Inc.	Gas	6444	9/22/00	6/6/01	9/30/99	5.1	5.1[36]	11.25	11.25

[30]Beginning of non-commodity rate freeze extending through 6/30/02 under approved extension of modified price stabilization plan.

[31]Settlement agreement includes indicated increase in annual distribution revenues in the form of an offset to a $9 million reduction in fixed pipeline costs.

[32]Earnings above figure shown to be refunded to ratepayers. Reduction to prior ROE reflects commission dissatisfaction with utility supply procurement practices.

[33]Filing pursuant to state restructuring law. Proceeding concerning unbundling of distribution assets and services.

[34]Commission approved generic ROE of 11.25% for distribution-only operations by order dated 12/18/00 in Docket No. 22344.

[35]Approved settlement agreement allows 3.95% increase over existing temporary rates. Award departs from traditional cost-of-service ratemaking by allowing recovery of Hydro Quebec Power costs found both imprudent and not economically useful.

[36]See *Re Vermont Gas Systems, Inc.*, 208 PUR4th 286 for prior order approving a settlement authorizing a permanent increase in firm rates of 15.4% follwoing increases in cost of wholesale gas supply.

Authorized Rate of Return on Common Equity

Company Name	*Type of Service (Electric or Gas)*	*Case, Docket, or Decision No.*	*Application Date*	*Order Date*	*Test-year End Date*	*Increase Requested ($million)*	*Increase Granted [Decrease] ($million)*	*Rate of Return on Common Equity*	
								Previously Authorized Rate (%)	*Newly Authorized Rate (%)*
VIRGINIA									
United Cities Gas Co.	Gas	PUE000171	3/24/00	5/22/01	12/31/99	2.051	[.534]	NA	11.0[37]
WASHINGTON									
Avista Corp.	Electric	UF-991606 *204 PUR4th 1*	10/22/99	9/29/00	12/31/98	26.25	[3.41]	12.9	11.16
Avista Corp.	Gas	UG-991607 *204 PUR4th 1*	10/22/99	9/29/00	12/31/98	4.9	1.67	10.75	11.16
Northwest Natural Gas Co.	Gas	UG-000073	1/21/00	10/26/00	12/31/99	6.2	4.3	11.25	10.8
WISCONSIN									
Madison Gas & Electric Co.	Electric	3270-UR-110	4/17/00	12/22/00	12/31/01	9.5	7.5	12.2	12.9
Madison Gas & Electric Co.	Gas	3270-UR-110	4/17/00	12/21/00	12/31/01	4.5	3.4	12.2	12.9
Midwest Natural Gas, Inc.	Gas	3670-GR-102	2/27/00	5/1/01	12/31/01	.6	.6	12.50	12.25
Northwestern Wisconsin Electric Co.	Electric	4280-ER-103	10/27/00	6/29/01	12/31/01	NA	.367	NA	12.75
Wisconsin Public Service Corp.	Electric	6690-UR-112 *206 PUR4th 1*	3/31/00	12/22/01	12/31/01	44.1[38]	27.1	12.1	12.1[39]
Wisconsin Public Service Corp.	Gas	6690-UR-112 *206 PUR4th 1*	3/31/00	12/22/01	12/31/01	4.9[38]	4.3	12.1	12.1[39]

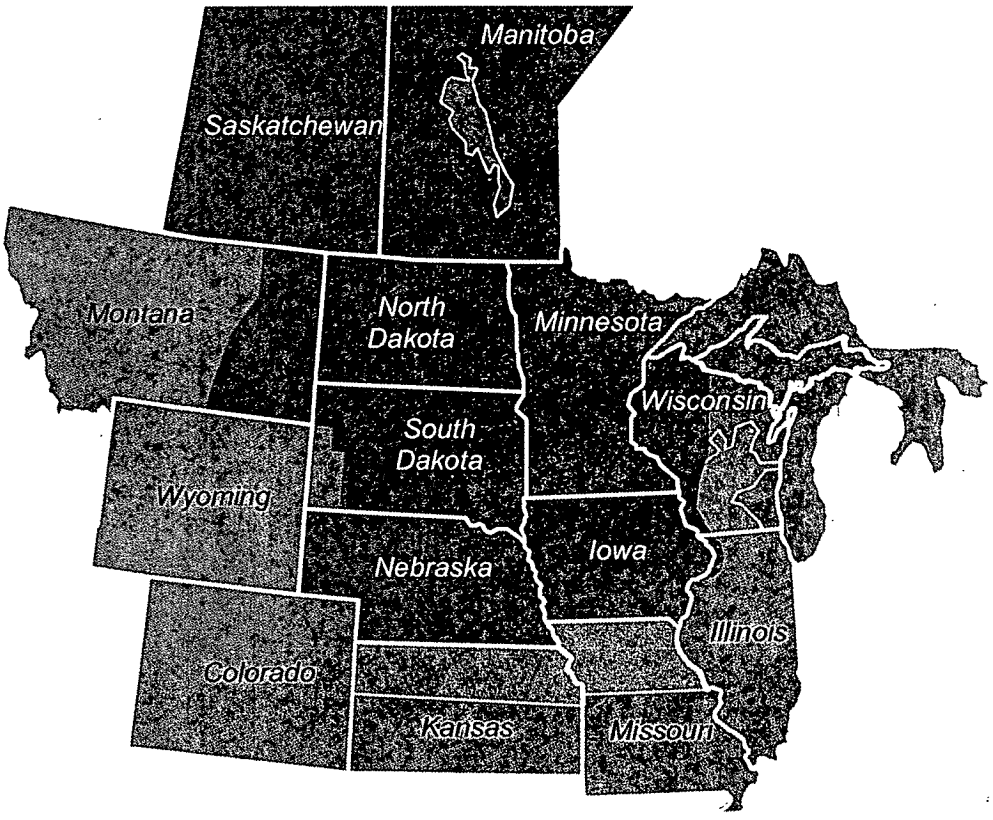
[37]ROE figure stated in approved settlement agreement.

[38]Utility also requested $12.2 million electric and $3.7 million gas revenue increase to take effect beginning in 2002. No change for 2002 authorized by commission.

[39]Utility did not request a change in ROE in this docket.

mapp℠

mid-continent area power pool



2001 Update to the 2000 Regional Plan

2000 through 2009

EXHIBIT
13
Dag 2/25/02

Prepared by:
Transmission Planning Subcommittee (TPSC)

November 30, 2001

MAPP, MAPPCOR and Mid-Continent Area Power Pool are service marks of MAPPCOR.

79 PU-399-01-186 Pages: 41

MAPP 2001 update to the 2000 regional plan
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 13
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

List of Acronyms and Abbreviations

ACRONYM	CORRESPONDS TO
ACCC	Automatic Contingency Screening Analysis
ACSR	Aluminum Conductor, Steel Reinforced
ALT	Alliant Energy
ALTW	Alliant West
ATC	Available Transfer Capability
BEPC	Basic Electric Power Cooperative
CBPC	Corn Belt Power Cooperative
CC	Combined Cycle Generation Plant
CCS	Coal Creek Station
CFU	Cedar Falls Municipal Utilities
CIPCO	Central Iowa Power Cooperative
COOPER_S	Cooper South Flowgate (located in southeast Nebraska)
CT	Combustion Turbine
CUDC	Cooperative Power / UPA (United Power Association) Direct Current line
DAEC	Duane Arnold Energy Center
DCLFG	Douglas County Land Fill Generation in Bennington, NE
DPC	Dairyland Power Cooperative
DRS	Design Review Subcommittee
ECL-ARP	Eau Claire to Arpin Flowgate (located in northwestern/central Wisconsin)
EREPC	East River Electric Power Cooperative
FCTS	Firm Capacity Transmission Service
FERC	Federal Energy Regulatory Commission
FRET	Fremont Department of Utilities
FTCAL_S	Fort Calhoun South Flowgate (power flow south out of Fort Calhoun plant)
GCW	Gray County Wind Farm in Montezuma, KS
GGS	Gerald Gentlemen Station Flowgate (stability interface, located in western Nebraska)
GRE	Great River Energy
GRIS	Grand Island Utilities Dept.
GRIS_LNC	Grand Island-Lincoln Flowgate (located in east central Nebraska)
GWH	Gigawatt Hours
HCPD	Heartland Consumers Power District
HNF or HN	Hourly Non-Firm Transmission Service
HUC	Hutchinson Utilities Commission
IAMU	Iowa Association of Municipal Utilities
IBC	International Boundary Commission
IPP	Independent Power Producer

(continued)

ACRONYM	CORRESPONDS TO
ITWG	Iowa Transmission Working Group
KCPL	Kansas City Power & Light
LES	Lincoln Electric System
LLR	Line Loading Relief
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MBSPG	Missouri Basin Subregional Planning Group
MBWG	Model Building Working Group
MDU	Montana Dakota Utilities
MEAN	Municipal Energy Agency of Nebraska
MEC	MidAmerican Energy Company
MH	Manitoba Hydro
MHEX	Manitoba – United States transmission interface
MHEX_N	Manitoba Hydro Import North Flowgate (thermal & stability interface power flow from the south into Manitoba)
MHEX_S	Manitoba Hydro Export South Flowgate (stability interface power flow out of Manitoba to the south)
MH-US	Manitoba Hydro – United States
MNEX	Minnesota Export Flowgate (stability interface located south and east of the Twin Cities)
MORR	MAPP's Operating Reserve Requirements
MP	Minnesota Power
MPW	Muscatine Power and Water
MRD	Market Redispatch
MRES	Missouri River Energy Services
MVA	Megavolt Ampere
MVAR	Mega Volt Ampere Reactive
MW	Megawatt
MWH	Megawatt Hours
NDEX	North Dakota Export Flowgate (stability interface located in the Dakotas)
NDIC	North Dakota Industrial Commission
NEB	National Energy Board
NERC	North American Electric Reliability Council
NI_WUMS	Northern Illinois to Wisconsin Upper MI Systems Flowgate
NIPCO	Northwest Iowa Power Cooperative
NPPD	Nebraska Public Power District
NSP	Xcel Energy/Northern States Power
NWPS	Northwestern Public Service Company
OASIS	Open Access Same-time Information System
OPPD	Omaha Public Power District
OTP	Otter Tail Power Company
POD	Point of Delivery

(continued)

ACRONYM	CORRESPONDS TO
POR	Point of Receipt
PRI-BYN	Prairie Island to Byron Flowgate (thermal and stability interface south of the Twin Cities)
PSC	North Dakota Public Service Commission
PSS/E	Power System Simulator/Engineering
QCPS	Quad Cities Power Station
RNF	Refused Non Firm
RPGI	Resale Power Group of Iowa
RPU	Rochester Public Utilities
RRV	Red River Valley
RRV/WMN TIPS	Red River Valley / West Central Minnesota Transmission Improvement Planning Study
RRVSPG	Red River Valley Subregional Planning Group
SECI	Sunflower Electric Power Co.
SMMPA	Southern Minnesota Municipal Power Agency
SPG	Subregional Planning Group
SPP	Southwest Power Pool
SRD	System Redispatch
SVC	Static Var Compensator
TLR	Transmission Loading Relief
TPSC	Transmission Planning Subcommittee
UMVSPG	Upper Mississippi Valley Subregional Planning Group
UUI	Utilicorp United Incorporated
WAPA	Western Area Power Administration
WIRE	Wisconsin Interface Reliability Enhancement study
WNE WKS	Western Nebraska-Western Kansas Transmission Interface
WPL	Wisconsin Power and Light Co.
XCEL	Xcel Energy

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Section 1. Introduction

The MAPP Restated Agreement states that the Regional Plan should be updated as appropriate between biennial planning cycles, and that the TPSC should approve any such updates and modifications to the Plan. The TPSC has a developed procedure for implementing an Update to the Plan. This procedure requires the SPGs, on an ongoing basis, to review individual utility plans and evaluate the impacts on the subregion. Significant impacts are to be reported to the TPSC. All SPGs have submitted changes to their respective Subregional Plans. The TPSC has reviewed these changes and concluded that an update to the 2000 Plan is appropriate. The TPSC-approved Update to the 2000 Regional Plan is described here.

The MAPP 2000 Regional Plan was completed on December 29, 2000. The reader of this 2001 Update to the 2000 MAPP Regional Plan should have access to and acquired some familiarity with the original report. For Internet users, the original report may be found at http://www.mapp.org/Library/RegionPlan.htm by clicking on "MAPP 2000 Regional Plan".

Since the 2000 Regional Plan report, new studies have been completed within most SPGs. The TPSC has not initiated any new study work, but did update the assessment of constraints based on more recent OASIS request refusals and congestion management activities. The listings of projects (TPSC Form 1 through Form 3, and Form 4, the planning map) have been updated. The TPSC also concluded that the magnitude of simultaneous transfer capability as discussed in the 2000 Regional Plan remains about the same.

The updated OASIS assessment has confirmed that transfer capability increases are needed between MAPP and MAIN, and between MAPP and SPP. As recommended in the 2000 Regional Plan, a study group comprised primarily of Nebraska and Iowa transmission utility planners has been formed. This group is actively working and the TPSC expects to have the Nebraska/Iowa study group's findings available for inclusion in a pending 2002 Regional Transmission Plan. A recommendation from the Nebraska/Iowa study group coupled with the recent regulatory approval for proceeding with the Arrowhead-Weston 345 kV line (Duluth, MN, to Wausau, WI) should provide clear focus on these key expansion plans that address earlier and current TPSC recommendations.

Section 2. Overview of Changes and Plan Status

This section reviews changes since the December 29, 2000 date of the original report and illustrates the updated status of planned facilities. Categories included are lines, transformers, devices (capacitors) and generators.

2.1 Lines

The original 2000 Regional Plan indicated that 2,788 miles would be constructed new, converted, or upgraded for capacity increases. Line capacity increases would be due to reconductoring or increasing the capacity of associated facilities (such as breakers, transformers, switches, etc.). This 2001 Update to the 2000 Regional Plan indicates that another 584 miles of line will be constructed new, converted, or upgraded for capacity increases due to reconductoring or increasing the capacity of associated facilities. This overall impact is summarized in Table 2.1-1.

Table 2.1-1. Changes Reported Since the 2000 Regional Plan

Changes Since Original 2000 Regional Plan:	2001	2000	Change
Reconductor or Thermal Increase	692	493	199
Rebuilt or Conversion	952	541	411
New Construction	1,728	1,754	-26
Sum of Changes for All Types	3,372	2,788	584

Tables 2.1-2 through 2.1-5 show how the different components of planned transmission expansion differ from what was summarized in the original 2000 Regional Plan report. These tables summarize planned improvements by transitioning from the least right of way sensitive type (reconductoring) to ones that would require new construction. Some shifting has occurred among categories (reconductoring now being realized as rebuild, etc.) as shown in Tables 2.1-2 through 2.1-4. The changes reflect the results of additional plans that have now matured during the past year. The major projects defined in the 2000 plan have not changed. The Harvey (in northern ND) to Glenboro (in southwest Manitoba) 230 kV line and an Arrowhead (at Duluth, MN) to Weston (Wausau, WI) 345 kV line still remain as the major plans for the region.

While the 2001 update to the 2000 Regional Plan indicates an additional 584 miles of improvement over the 10 year plan horizon compared to the original report, some facilities have already been constructed new, converted, or upgraded for capacity increases due to reconductoring or increasing the capacity of associated facilities. This progress is reported as facilities "completed". For example, 527 miles of transmission have been constructed new, converted, or upgraded for capacity increases due to reconductoring or increasing the capacity of associated facilities. Tables 2.1-6 through 2.1-9 summarize the lines that have been completed after the release of the 2000 Regional Plan. Section 4 lists in detail the lines, transformers, capacitors, and generators that have been confirmed as in service since the 2000 Regional Plan was released.

The update of Form 1 (Appendix A) gives other specific information as to which lines are authorized, versus planned, withdrawn, or completed. Original information is displayed in a clear cell, and changed data or new data are shown as red font.

Table 2.1-2 Changes Since 2000 Reported for Lines Reconductored or Gaining Increased Thermal Capacity (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	88	0	0	0	0	88
MB	0	0	0	0	0	-110	-110
Nebraska	0	0	0	17	0	46	63
RRV	0	0	0	0	0	0	0
UMV	0	54	0	-58	0	162	158
Total	0	142	0	-41	0	98	199

Table 2.1-3. Changes Reported Since 2000 for Lines Rebuilt to the Same Voltage or Rebuilt from a Lower Voltage (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	0	0	0	0	0	0
MB	0	0	0	0	0	278	278
Nebraska	0	0	0	0	0	0	0
RRV	0	0	0	0	0	15	15
UMV	0	0	0	79	0	39	118
Total	0	0	0	79	0	333	411

Table 2.1-4. Changes Reported Since 2000 for Planned Lines Involving New Construction (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	0	0	8	0	0	8
MB	0	52	0	0	0	0	52
Nebraska	0	21	50	14	0	1	85
RRV	0	0	-141	0	0	31	-111
UMV	0	33	0	-20	0	-74	-60
Total Change Due to Update	0	106	-91	2	0	-43	-26

Table 2.1-5. Changes Reported Since 2000 for Sum of Line Improvement Types (Miles)

	Voltage						
Improvement Type:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
Reconductor or Thermal Increase	0	142	0	-41	0	98	199
Rebuilt or Conversion	0	0	0	79	0	333	411
New Construction	0	106	-91	2	0	-43	-26
Sum of Changes for all Types	0	248	-91	40	0	387	584

Table 2.1-6. Completed Reconductoring or Thermal Capacity Increase Since the 2000 Regional Plan (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	72	0	0	0	0	72
MB	0	0	0	0	0	0	0
Nebraska	0	0	0	0	0	35	35
RRV	0	0	0	0	0	0	0
UMV	0	0	0	2	0	13	15
Total	0	72	0	2	0	48	122

Table 2.1-7. Completed Rebuilds of Same Voltage or Rebuilt from a Lower Voltage Since the 2000 Regional Plan (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	0	0	0	0	0	0
MB	0	0	0	0	0	0	0
Nebraska	0	0	0	23	0	0	23
RRV	0	0	0	0	0	0	0
UMV	0	0	0	56	0	53	109
Total	0	0	0	79	0	53	132

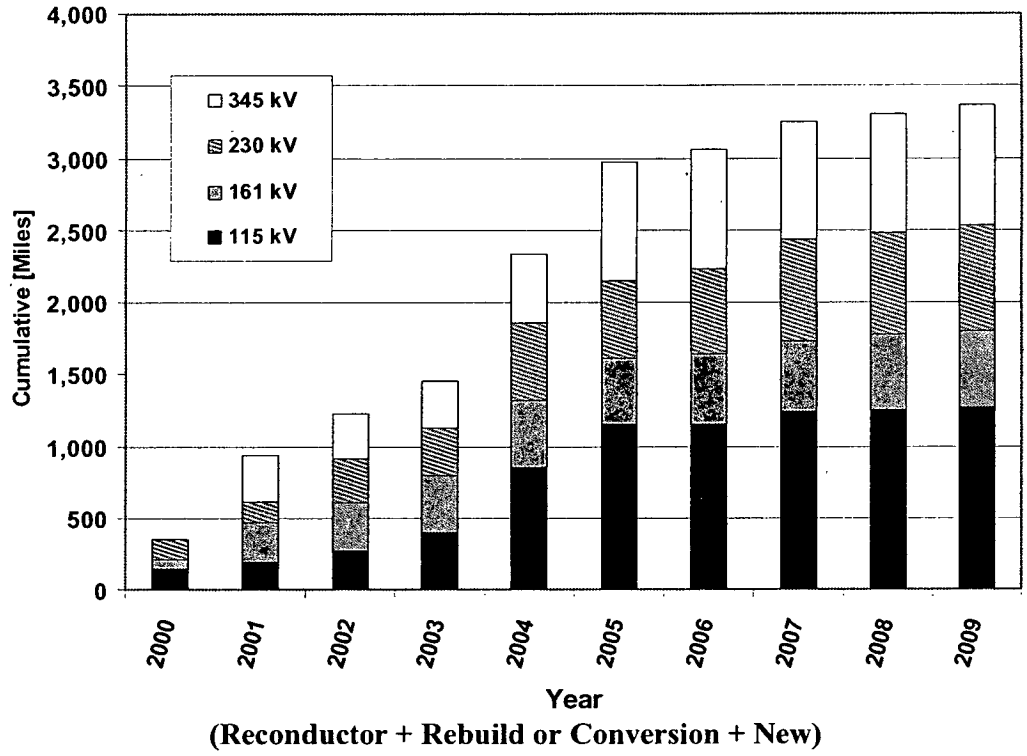
Table 2.1-8. Planned Lines Involving New Construction Completed Since the 2000 Regional Plan (Miles)

	Voltage						
SPG:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
ITWG	0	0	0	15	0	0	15
MB	0	0	0	0	0	0	0
Nebraska	0	0	0	37	0	24	61
RRV	0	0	144	0	0	25	169
UMV	0	0	0	16	0	12	28
SPG New Const.	0	0	144	68	0	61	273

Table 2.1-9. Sum of Line Improvement Types Completed Since the 2000 Regional Plan (Miles)

	Voltage						
Improvement Type:	500 kV	345 kV	230 kV	161 kV	138 kV	115 kV	All
Reconductor or Thermal Increase	0	72	0	2	0	48	122
Rebuilt or Conversion	0	0	0	79	0	53	132
New Construction	0	0	144	68	0	61	273
Sum of All Types	0	72	144	149	0	161	527

By 2009, a total of 3,372 miles of transmission line improvements are planned (Figure 2.1-1). About 1,700 miles of that is attributed to new construction (Figure 2.1-2).



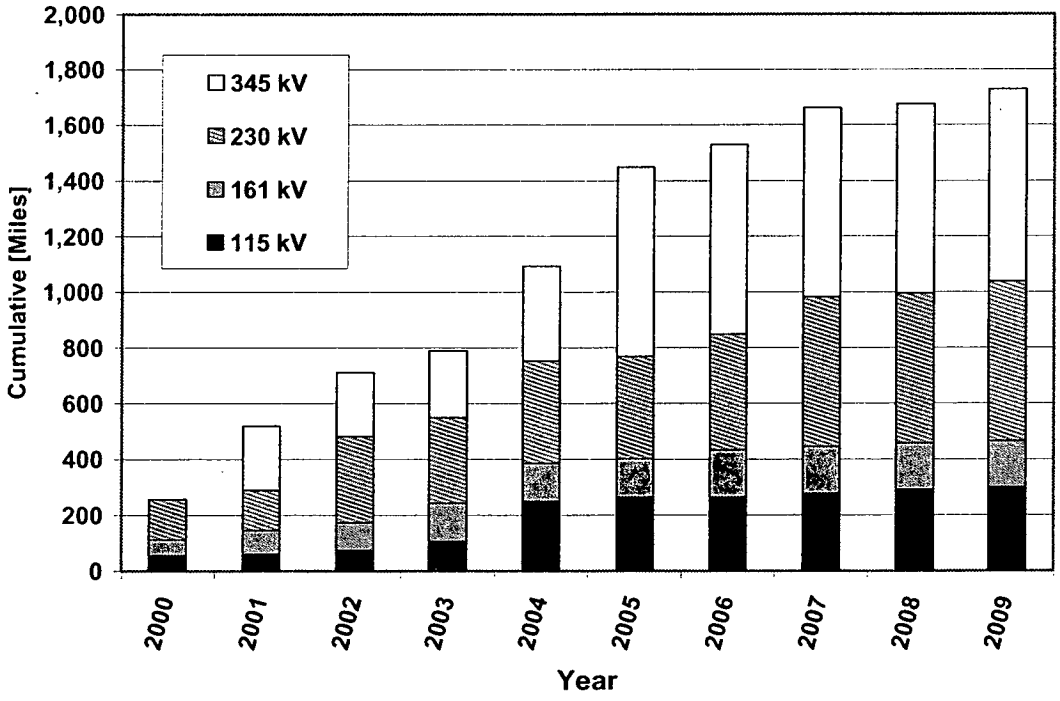


Figure 2.1-2. Cumulative New Transmission Lines (Miles)

The increase in 230 kV miles in 2002 is due to the new 230 kV Harvey-Glenboro line and the increase in 345 kV miles in 2005 is due to the Arrowhead – Weston line. The increase in 230 kV line miles in 2007 represents construction of new transmission in Manitoba.

2.2 Transformers

The cumulative status of transformer reporting on Form 1 (Appendix A) shows a total of 15,543 MVA of transformers being added by 2009. Figure 2.2 illustrates how that is expected to occur by voltage class from 2000 through 2009.

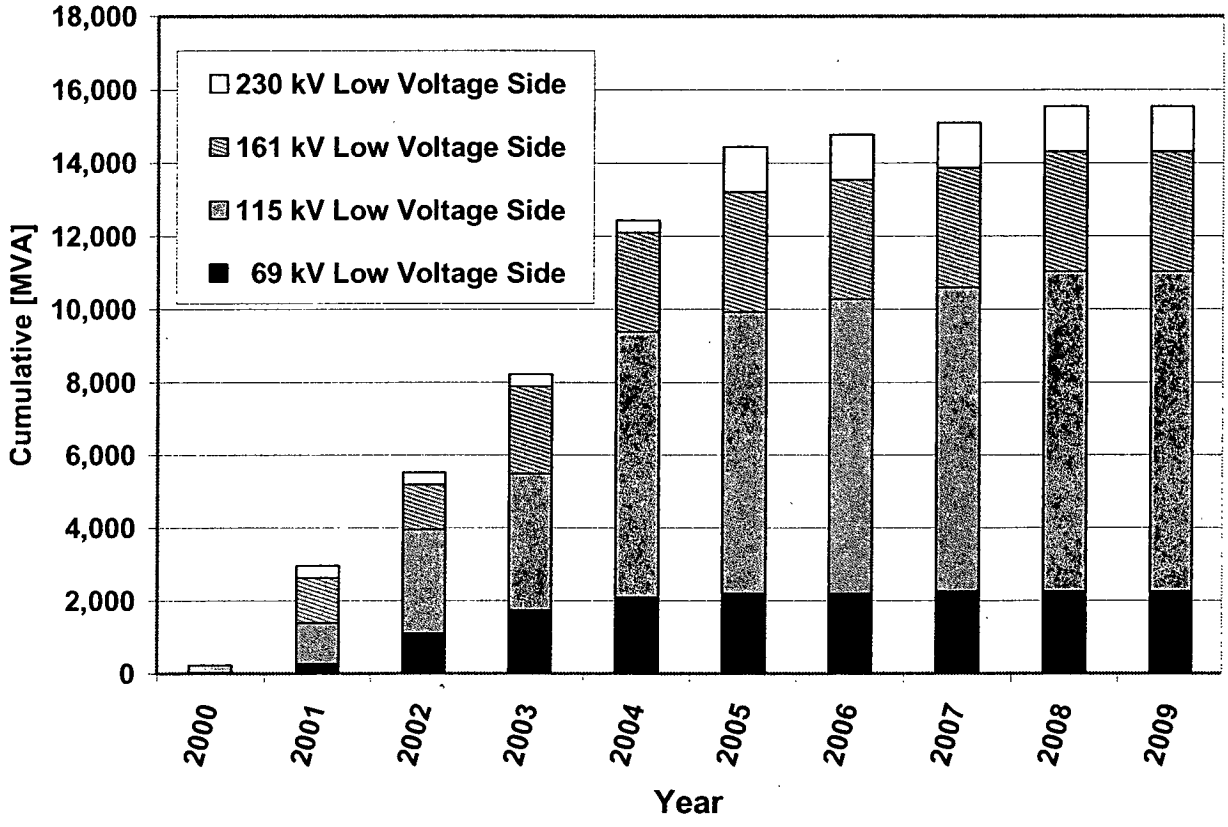


Figure 2.2. Cumulative Additional Transformer Capacity (MVA)

2.3 Devices

The 2001 Update status of Devices and changes to the 2000 Regional Plan are summarized on updated Form 2 (Appendix A). All device changes involve reactive power devices, and most changes were from capacitors. The reporting process does not include tracking individual circuit breaker installations. Rather, circuit breaker installations are reflected in the planning process by how they redefine modeling a contingency in loadflow or stability studies. Also, when doing economic comparisons of plans, the costs of breakers are included in the evaluations. The capacitor and synchronous condenser plans totaling 3,915 MVAR by 2009 are shown in Figure 2.3.

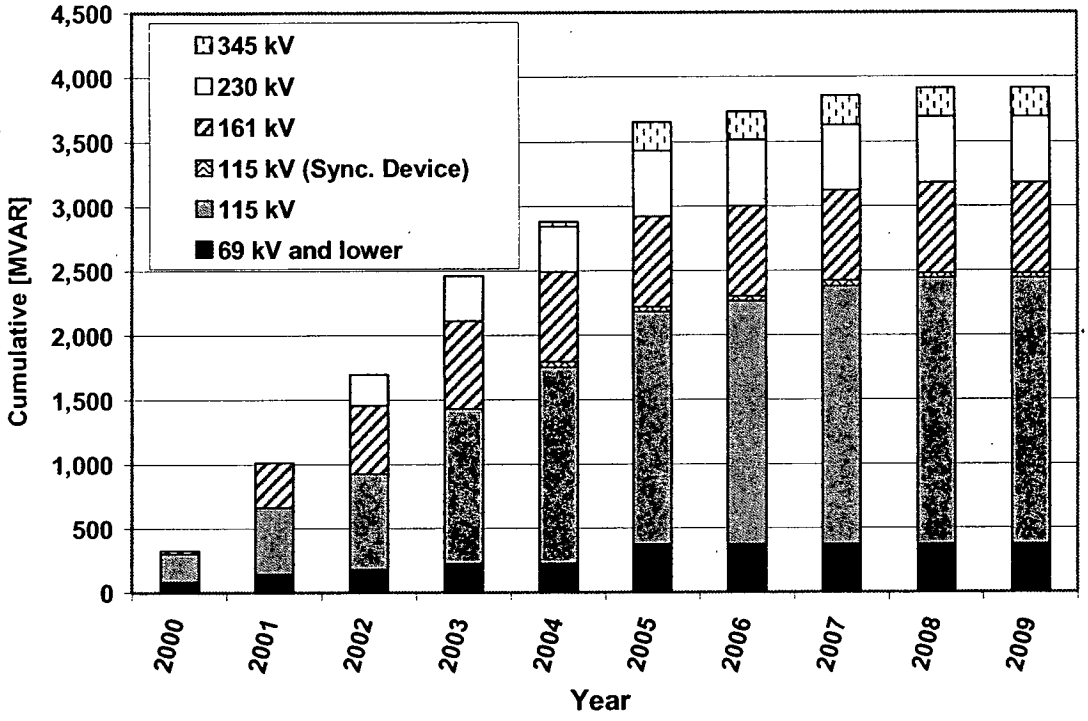


Figure 2.3. Cumulative New Reactive Power Supply (MVAR) (Transmission Capacitors + Synchronous Devices)

2.4 Generators

A total of 12,462 MW of generation is reported by 2009. When this total is reflected to site status, 2973 MW (or 23.9%) is completed, 6,786 MW (or 54.4%) are site-planned, and 2,704 (or 21.7%) are not site-specified. All un-sited generation is scheduled after the year 2001. Figure 2.4-1 shows the cumulative MW of completed, sited, and un-sited generation starting with the base line year 2000. The un-sited capacity in Figure 2.4-1 reflects an "Authorized" gas-fired project in 2002 at 110 MW. The remaining un-sited projects have "Planned" status.

Figure 2.4-2 represents a further breakdown of the sited versus non-sited generation by dispatch type (Base, Intermediate, Peaking, and Wind). The capacity for wind generation in Figures 2.4-1 and 2.4-2 is on the basis of estimated accredited capacity for summer reserves. The nameplate rating for wind installations are usually about 5 times higher. The energy from wind on the lower accredited base can exceed 100% capacity factor. Therefore, the MW capacities for wind in Figures 2.4-1 and 2.4-2 are considered as Base load. See Table 2.4 for the listing of generation categorized by site status and identification of dispatch type applied. Detailed changes to generation plans are summarized on updated Form 3 (Appendix A). The update version of Form 3 retains the identity of old versus new information by indicating any changed data or new data with a red font.

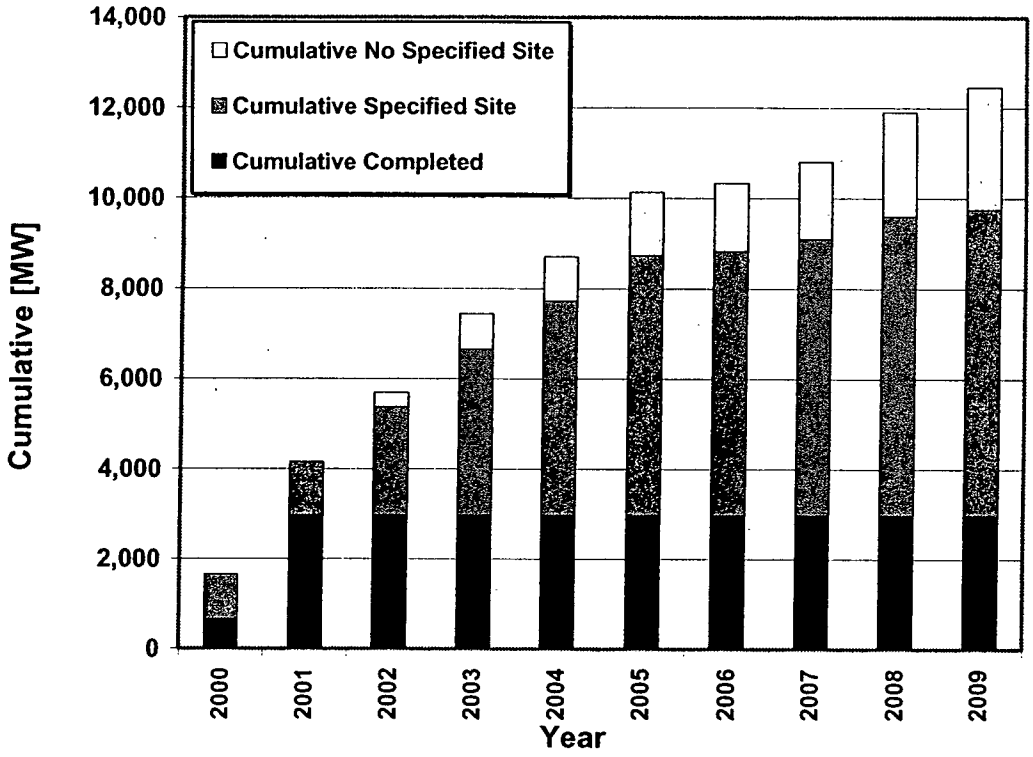


Figure 2.4-1. Sited and Un-Sited Generation

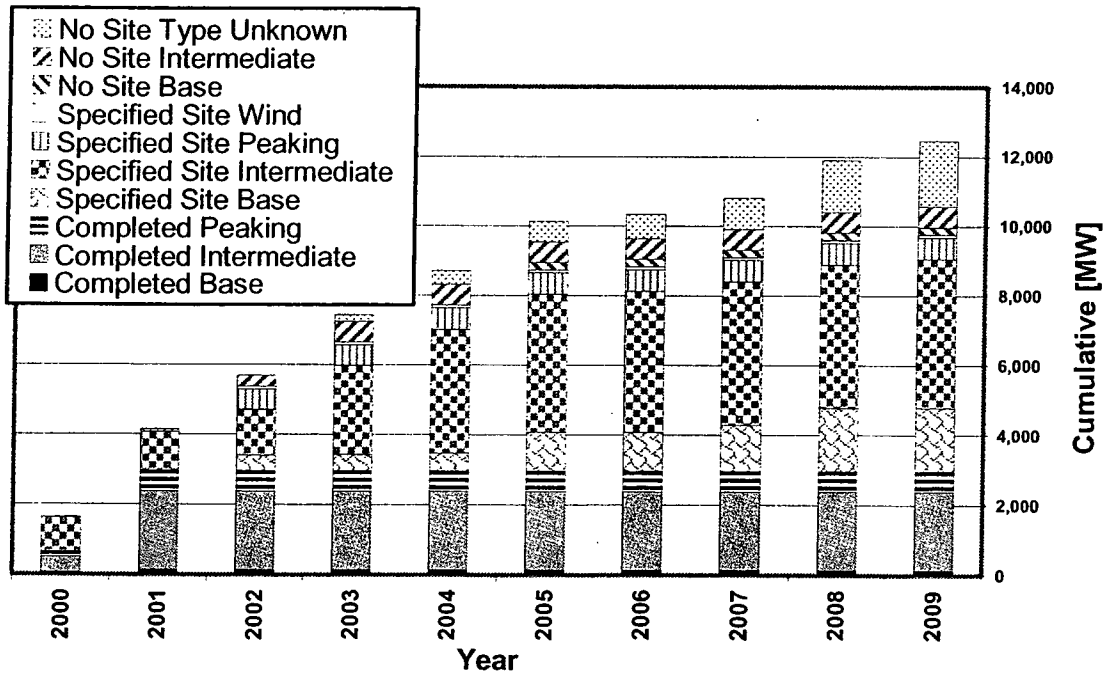


Figure 2.4-2. Generation Site Status and Type

Table 2.4. Generating Units By Date and Siting Status (Includes Completed Units)

																Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not ?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base i=intermediate p=peaking u=unknown
5/1/1999	UMV	Peaking / Diesel	Lakefield, MN	2.4/69	3					X	C	MRES	YES	3	3.00			p
4/1/2000	ITWG	South Load Center Diesels	Waverly, Iowa	13.8	12	0-20%	X				C	IAMU	YES	12	12.00			p
5/8/2000	ITWG	Stuart	Stuart, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
6/1/2000	ITWG	Anita Unit 4	Anita, IA	2.4	0.295	0-10%	X				C	IAMU	YES	0.295	0.30			p
6/1/2000	ITWG	Anita Unit 5	Anita, IA	2.4	0.295	0-10%	X				C	IAMU	YES	0.295	0.30			p
6/1/2000	ITWG	Maquoketa 9	Maquoketa, IA	12	1.825	0-10%	X				C	IAMU	YES	1.825	1.83			p
6/1/2000	ITWG	La Porte 2A	La Porte, IA	2.4	1.825	0-10%	X				C	IAMU	YES	1.825	1.83			p
6/1/2000	ITWG	La Porte 4A	La Porte, IA	2.4	1.825	0-10%	X				C	IAMU	YES	1.825	1.83			p
6/1/2000	ITWG	Sibley 4	Sibley, IA	2.4	2	0-10%	X				C	IAMU	YES	2	2.00			p
6/1/2000	ITWG	New London 1	New London, IA	12	2	0-10%	X				C	IAMU	YES	2	2.00			p
6/1/2000	ITWG	New London 2	New London, IA	12	2	0-10%	X				C	IAMU	YES	2	2.00			p
6/1/2000	ITWG	New London 3	New London, IA	12	2	0-10%	X				C	IAMU	YES	2	2.00			p
6/1/2000	ITWG	Story City 4	Story City, IA	12	3	0-10%	X	X			C	IAMU	YES	3	3.00			p
6/1/2000	ITWG	MEC Landfill Generation	Quad Cities	69	3					X	C	MEC	YES	3	3.00			i
6/1/2000	ITWG	Pella	Pella, IA		4		X				C	IAMU	YES	4	4.00			p
6/1/2000	UMV	Lake Marion	Lakeville	12.47/69	8.8	0-20 %	X				C	GRE	YES	8.8	8.80			p
6/1/2000	UMV	Hastings	Hastings	12.47/69	8.8	0-20 %	X				C	GRE	YES	8.8	8.80			p
6/1/2000	ITWG	MEC Des Moines Generation	Des Moines	69	12		X				C	MEC	YES	12	12.00			p
6/1/2000	ITWG	MEC Knoxville Units	Knoxville	69	16		X				C	MEC	YES	16	16.00			p
6/1/2000	ITWG	MEC Shenandoah Units	Shenandoah	69	20		X				C	MEC	YES	20	20.00			p
6/1/2000	ITWG	MEC Lundquist Units	Lundquist	69	20		X				C	MEC	YES	20	20.00			p
6/1/2000	ITWG	MEC Indianola Generation	Indianola	69	25		X	X			C	MEC	YES	25	25.00			l
6/1/2000	ITWG	AMES	Ames	69	34.1				X		C	MEC	YES	34.1	34.10			b

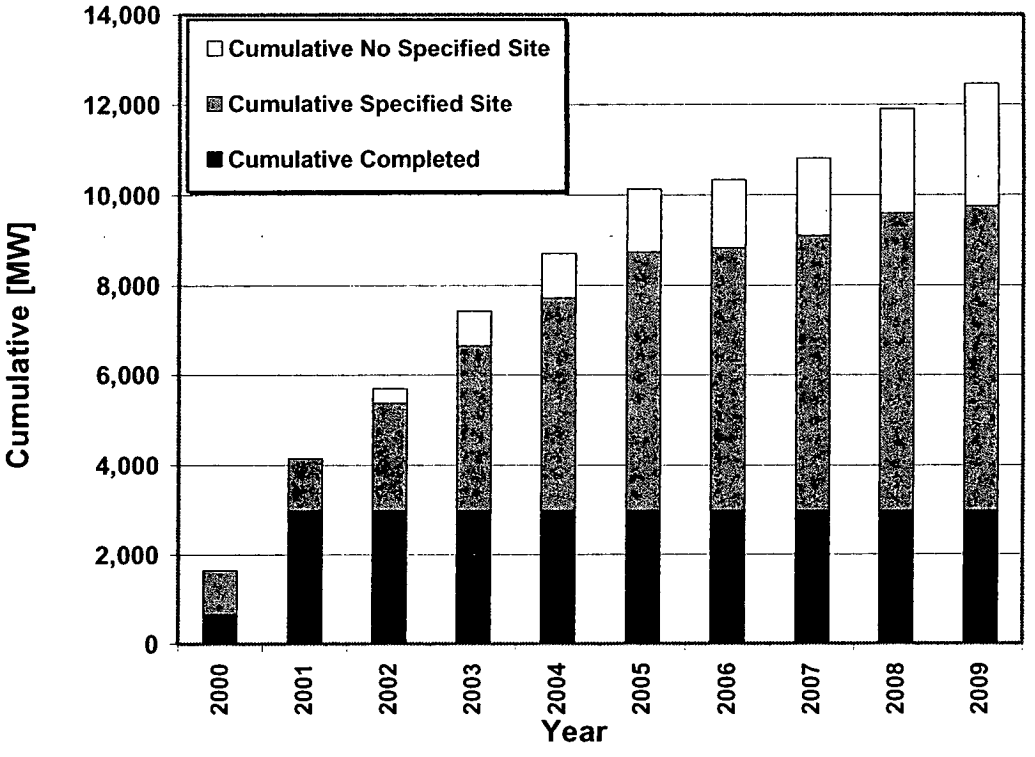


Figure 2.4-1. Sited and Un-Sited Generation

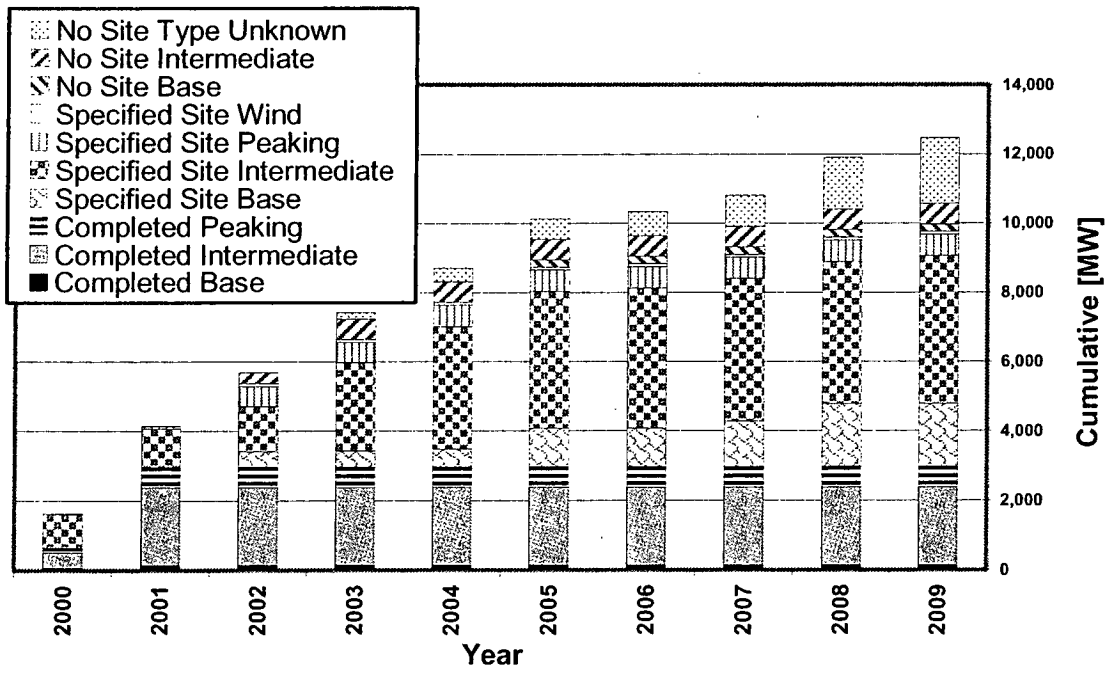


Figure 2.4-2. Generation Site Status and Type

																Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not ?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base l=intermediate p=peaking u=unknown
6/1/2000	NEBRASKA	Hawthorn Unit #7	Kansas City, MO	161 KV	80			X			C	KCPL	YES	80	80.00			i
6/1/2000	NEBRASKA	Hawthorn Unit #8	Kansas City, MO	161 KV	80			X			C	KCPL	YES	80	80.00			i
6/1/2000	NEBRASKA	Sarpy County Units #4 & #5	Omaha, NE	161 KV	95			X			C	OPPD	YES	95	95.00			i
6/1/2000	NEBRASKA	Hawthorn Unit #9	Kansas City, MO	161 KV	140			X		X	C	KCPL	YES	140	140.00			i
7/1/2000	ITWG	MPW Unit 8A	Muscatine, IA	69	16.3/18.4	90%			X		C	MPW	YES	16.3	16.30			b
7/1/2000	ITWG	MPW Unit 8	Muscatine, IA	69	36/24.2	80%			X		C	MPW	YES	36	36.00			b
8/1/2000	ITWG	Dayton	Dayton, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
8/31/2000	ITWG	Cedar Falls CT #2	Cedar Falls GT sub, IA	69	24/28		X	X			C	CFU	YES	24	24.00			p
9/1/2000	ITWG	Panora	Panora, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
1/1/2001	UMV	Gas Turbine	Mower Cty MN, P. Valy. Twp	161	310/352	0-15 %		X			C	GRE	YES	310	310.00			p
4/1/2001	UMV	Utilities Plus	Windom		2 mw						C	XEL	YES	2	2.00			p
5/1/2001	ITWG	Earlville	Earlville, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
5/1/2001	ITWG	Lenox	Lenox, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
5/1/2001	UMV	Chaska (MN River)	Chaska, MN	115	45			X			C	XEL	YES	45	45.00			i
5/1/2001	ITWG	DAEC (Increased Capacity)	Cedar Rapids, IA	161	65	100%				X	C	Alliant	YES	65	65.00			b
5/1/2001	NEBRASKA	Rokeby CT Unit #3	Lincoln, NE	115 KV	93 / 98			X			C	LES	YES	93	93.00			i
6/1/2001	UMV	Diesel	Forest City, IA	69	6	0-8%	X				C	DPC	YES	6	6.00			p
6/1/2001	UMV	Diesel	Lake Mills, IA	69	6	0-8%	X				C	DPC	YES	6	6.00			p
6/1/2001	UMV	Diesel	Fennimore, WI	69	2 X 3	0-8%	X				C	DPC	YES	6	6.00			p
6/1/2001	UMV	Elk Mound	Eau Claire Cnty, WI	161	84/96	0-20 %	X	X			C	DPC	YES	84	84.00			p
6/1/2001	UMV	Lakefield Junction	Martin County, MN	345	550	0-20%		X			C	NRG/ Tenaska	YES	550	550.00			i
6/1/2001	NEBRASKA	Aries Plant	Pleasant Hill, MO	161 KV	585			X			C	UUI/ MIPU	YES	585	585.00			i
7/1/2001	MAIN	Cordova Generators	Cordova, IL	345	178 / 230	50 -100%		X			C	MEC	YES	178	178.00			i
7/1/2001	MAIN	Cordova Generators	Cordova, IL	345	178 / 230	50 -100%		X			C	MEC	YES	178	178.00			i
7/1/2001	MAIN	Cordova Generators	Cordova, IL	345	181.5 / 230	50 -100%				X	C	MEC	YES	181.5	181.50			i
9/1/2001	UMV	Willmar	Willmar	69	12	0-20 %	X				C	GRE	YES	12	12.00			p

															Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not ?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base I=intermediate p=peaking u=unknown
12/1/2001	ITWG	Brooklyn	Brooklyn, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
12/1/2001	ITWG	Greenfield	Greenfield, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
12/1/2001	ITWG	Winterset	Winterset, IA	12	2	0-10%	X				C	CIPCO	YES	2	2.00			p
5/1/1999													YES			0.00		
6/1/2000	MAIN	River Falls Diesel additions and retirements		69	2 X 4.3		X				A	River Falls/ WPPI	YES	8.6		8.60		p
6/1/2000	UMV	New Ulm	New Ulm	69	10	0-20 %	X				P		YES	10		10.00		p
6/30/2000	MAIN	West Marinette	West Marinette, WI	138	82			X			A	MGE	YES	82		82.00		i
6/30/2000	MAIN	Germantown (new unit + upgrades)	Germantown, WI	138	133			X			A	WEPCO	YES	133		133.00		i
6/30/2000	MAIN	SEI	Neenah, WI	138	300			X			A	WPS/ SEI	YES	300		300.00		i
6/30/2000	MAIN	RockGen	Rockdale, WI	138	450			X			A	Alliant	YES	450		450.00		i
9/1/2000	UMV	Grantsburg	Grantsburg, WI	69	3 X 2		X				A	XEL	YES	6		6.00		p
5/1/2001	UMV	Utilities Plus	Sleepy Eye	69	2 mw						A	XEL	YES	2		2.00		p
5/1/2001	UMV	Peaking / Diesel	Westbrook, MN	12.47/69	3					X	A	MRES	YES	3		3.00		p
5/1/2001	UMV	Utilities Plus	Madelia	69	3 mw						A	XEL	YES	3		3.00		p
6/1/2001	UMV	New Ulm	New Ulm	69	26.5	0-20 %		X			P		YES	26.5		26.50		p
7/1/2001	UMV	Utilities Plus	Fairfax	69	2 mw						A	XEL	YES	2		2.00		p
7/1/2001	ITWG	Harlan	Harlan, IA		2.5		X				P	IAMU	YES	2.5		2.50		p
10/1/2001	UMV	Chaska (MN River)	Chaska, MN	115	4.9			X			A	XEL	YES	4.9		4.90		i
11/1/2001	UMV	Utilities Plus	Delano	69	12 mw						A	XEL	YES	12		12.00		p
12/1/2001	UMV	Univ. of MN SE Steam Plant	Mpls, MN	115	14				X		A	XEL	YES	14		14.00		i
12/1/2001	NEBRASKA	GCW Wind Farm	Montezuma, KS	115 KV	110					X	A	UUI	YES	110		110.00		i
12/31/2001	UMV	Wind (All Source-NAE)	Buffalo Ridge, MN (Murray Co)		50 (6.75)					x	A	XEL	YES	6.75		6.75		w
1/1/2002	NEBRASKA	Alliance Diesel Gens 3 @ 1.8 MW each	Alliance, NE	115 KV	5.4		X				A	MEAN	YES	5.4		5.40		p
1/4/2002	RRV	Gas Turbine	Brandon, MB	115 kV	2X115/136	0-20%		X			A	MH	YES	230		230.00		p
3/1/2002	UMV	Hurley (All Source-NAE)	Hurley, Wi	115	55			X			A	XEL	YES	55		55.00		i

SECTION 2: OVERVIEW OF CHANGES AND PLAN STATUS

																Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not ?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base i=intermediate p=peaking u=unknown
3/1/2002	UMV	Gas Turbine	Mower Cty MN, P. Valy. Twp	161	124/138	0-15%		X			A	GRE	YES	124		124.00		p
4/1/2002	UMV	Gingles (All Source-NAE)	Ashland, WI	115	55			X			A	XEL	YES	55		55.00		i
5/1/2002	RRV	Hillsboro, Diesel	Hillsboro, ND	69	4	8%				X	A	MRES	YES	4		4.00		p
5/1/2002	RRV	Benson, Diesel	Benson, MN	13.8/41.6	11	8%				X	A	MRES	YES	11		11.00		p
5/1/2002	UMV	Peaking / Diesel	Worthington, MN	12.47/69	18					X	A	MRES	YES	18		18.00		p
5/1/2002	RRV	Lindroc (Biomas II)	Bemidji or Int'l Falls, MN		25	70%				X	A	NSP	YES	25		25.00		b
5/1/2002	UMV	Cascade Creek Combustion Turbine	Rochester, MN	161	40/50	0-20%	X	X			A	RPU	YES	40		40.00		p
5/1/2002	RRV	Coal Creek Upgrade	Coal Creek Station, ND	230	72/72	80%			X		A	GRE	YES	72		72.00		b
6/1/2002	NEBRASKA	DCLFG Units 1-4	Bennington, NE	161 KV	3.2					X	A	OPPD	YES	3.2		3.20		p
6/1/2002	ITWG	Wilton	Wilton, IA	12	4.4		X				P	CIPCO	YES	4.4		4.40		p
6/1/2002	ITWG	Pella	Pella, IA		24		X				P	IAMU	YES	24		24.00		p
6/1/2002	UMV	West Faribault (All Source)	Faribault, MN	115	110			X			A	XEL	YES	110		110.00		i
6/1/2002	UMV	Black Dog combined cycle (Unit 5)	Black Dog	115	290/323			x			A	XEL	YES	290		290.00		b
10/1/2002	UMV	Diesel	Redwood Falls, MN	69	6		X				A	SMMPA	YES	6		6.00		p
12/1/2002	UMV	St. Boni (upgrade from 50/50))	St. Bonifacius, MN	69	16/20	0-15%	X				P	GRE	YES	16		16.00		p
12/1/2002	UMV	Chanarambie Power Partners LLC (Wind Phase IV)	Buffalo Ridge, MN		80 (accredit-ed)	35%				X	A	XEL	YES	80		80.00		w
12/31/2002	RRV	Fibro-Minn	Benson, MN	115	50	90%				X	P	GRE	YES	50		50.00		b
4/1/2003	UMV	Utilities Plus	Granite Falls		3- 2 mw						P	XEL	YES	3		3.00		p
5/1/2003	UMV	Utilities Plus	Sleepy Eye	69	2 mw						P	XEL	YES	2		2.00		p
5/1/2003	MB	Peaking / Diesel	Pierre, SD	12.47/115	12					X	P	MRES	YES	12		12.00		p
5/1/2003	UMV	St. Paul District Energy (Biomass II)	St. Paul, MN		25	70%				X	A	XEL	YES	25		25.00		b
5/1/2003	NEBRASKA	Cass County Unit #1	Plattsmouth, NE	345 KV	160			X			A	OPPD	YES	160		160.00		i
6/1/2003	NEBRASKA	Fremont CT	Fremont, NE	115 KV	50			X			A	FRET	YES	50		50.00		i
6/1/2003	ITWG	Des Moines Energy Center	Des Moines, IA	345	178 / 205	50 -100%		X			P	MEC	YES	178		178.00		i
6/1/2003	ITWG	Des Moines Energy Center	Des Moines, IA	345	178 / 205	50 -100%		X			P	MEC	YES	178		178.00		i

SECTION 2: OVERVIEW OF CHANGES AND PLAN STATUS

															Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not ?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base i=intermediate p=peaking u=unknown
6/1/2003	NEBRASKA	Paola CT's 3 @ 77 Mw each	Paola, KS	161 KV	231/240			X			P	KCPL	YES	231		231.00		i
7/1/2003	NEBRASKA	Cass County Unit #2	Plattsmouth, NE	345 KV	160			X			A	OPPD	YES	160		160.00		i
10/1/2003	NEBRASKA	Salt Valley Station CC Units 1-3	Lincoln, NE	115 KV	117			X			A	LES	YES	117		117.00		i
11/1/2003	UMV	Peaking	Superior, WI	115	160			X			P	MP	YES	160		160.00		i
5/1/2004	UMV	Utilities Plus	Glencoe	69	5 mw						P	XEL	YES	5		5.00		p
5/1/2004	RRV	Gas Turbine	Glendive, MT	115kV	33/38	0-20%	X	X			P	MDU	YES	33		33.00		p
5/1/2004	NEBRASKA	Salt Valley Station CC Units 4	Lincoln, NE	115 KV	45			X			A	LES	YES	45		45.00		i
5/1/2004	UMV	EPS/BeckPower (Biomass II)	St. Peter, MN		50	80%				X	A	XEL	YES	50		50.00		b
5/1/2004	NEBRASKA	Grand Island CT's 2 @ 40 MW each	Grand Island, NE	115 KV	80			X			A	GRIS	YES	80		80.00		i
5/1/2004	MB	Watertown	Watertown, SD	115	150			X			P	MRES	YES	150		150.00		i
6/1/2004	ITWG	Wisdom CT	Spencer, IA	69	80			X			P	CBPC	YES	80		80.00		i
6/1/2004	ITWG	Proposed Entergy IPP	Adair County, IA	345	171 /	50 -100%		X			P	MEC	YES	171		171.00		i
6/1/2004	ITWG	Proposed Entergy IPP	Adair County, IA	345	171 /	50 -100%		X			P	MEC	YES	171		171.00		i
6/1/2004	ITWG	Proposed Entergy IPP	Adair County, IA	345	289 /	50 -100%				X	P	MEC	YES	289		289.00		i
6/1/2005	ITWG	Des Moines Energy Center	Des Moines, IA	345	182 / 200	50 -100%				X	P	MEC	YES	182		182.00		i
6/1/2005	NEBRASKA	Beatrice CC	Beatrice, NE	115 KV	229			X			P	NPPD	YES	229		229.00		i
6/1/2005	NEBRASKA	Sand Sage Unit #1	Holcomb, KS	345 KV	600				X		P	SECI	YES	600		600.00		b
5/1/2006	ITWG	Denison	Denison, IA	115	50	30%	X	X			P	MRES	YES	50		50.00		i
5/1/2006	RRV	Moorhead #2	Moorhead, MN	115	50	30%	X	X			P	MRES	YES	50		50.00		i
5/1/2007	RRV	Gas Turbine	Glendive/Miles City, MT	115kV	2X33/38	0-35%	X	X			P	MDU	YES	66		66.00		i
6/1/2007	NEBRASKA	Hastings Energy Center # 2	Hastings, NE	115 KV	200				X		P	MEAN	YES	200		200.00		b
5/1/2008	RRV	LV21	Gascoyne, ND	230kV	500	80%			X		P	MDU	YES	500		500.00		b
6/1/2009	NEBRASKA	Cass County Unit # 3	Plattsmouth, NE	345 KV	160			X			P	OPPD	YES	160		160.00		i
5/1/2010	RRV	Moorhead #3	Moorhead, MN	115	50	30%	X	X			P	MRES	YES	50		50.00		i
5/1/1999													NO				0.00	
5/1/2000													NO				0.00	
5/1/2001													NO				0.00	

																Siting Status			Type
In Service Date (m/d/y)	MAPP Sub-Region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer / Winter Rating (MW)	Nominal Dispatch Capacity Factor	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn	Reporting Source	Sited or not?	Summer Accredited (MW)	Completed (MW)	Sited (MW)	Un-sited (MW)	w=wind b=base l=intermediate p=peaking u=unknown
5/1/2002	UMV	Northern Alternative Energies (All Source)	Unknown		110			X			A	XEL	NO	110			110.00	i
6/1/2002	UMV	Combined Cycle	Unknown	138	215			X			P	WPL	NO	215			215.00	i
5/1/2003	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
6/1/2003	UMV	Combined Cycle	Unknown	138	215			X			P	WPL	NO	215			215.00	i
6/1/2003	UMV	Peaking Gas Turbine	Unknown		49			X			P	SMMPA	NO	49			49.00	i
5/1/2004	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2005	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
6/1/2005	UMV	Combined Cycle	Unknown	138	215			X			P	WPL	NO	215			215.00	b
5/1/2006	UMV	Various	To Be Competitively Bid		100						P	XEL	NO	100			100.00	u
5/1/2007	UMV	Various	To Be Competitively Bid		100						P	XEL	NO	100			100.00	u
5/1/2007	UMV	Various	To Be Competitively Bid		100						P	XEL	NO	100			100.00	u
5/1/2008	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2008	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2008	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2009	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2009	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
5/1/2010	UMV	Various	To Be Competitively Bid		200						P	XEL	NO	200			200.00	u
														Total MW	**2,973**	**6,836**	**2,904**	12,713
														Total Percent	**23.4%**	**53.8%**	**22.8%**	

See Form 3 (Appendix A) for complete generation information.

2.5 Historical Performance and Market Use of Point-to-Point Service

This section reviews the OASIS reservation refusals. This type of review is valuable because it reveals where the desire to use the transmission system exceeds the Available Transfer Capability (ATC). Compared to the 2000 plan, this update incorporates an additional 17 months of data and confirms that the primary transmission need is for greater transfer capacity between MAPP and MAIN, and between MAPP and SPP. In addition to confirming these locations for increased transmission tie capacity, data from recent months have confirmed that the need is also bi-directional. Earlier review only confirmed the need for exporting power out of MAPP. The dashed line in Figure 2.5-1 illustrates the geographic location of the bi-directionally constrained boundary on the transmission system.

Improvements located to the northwest of the bi-directional boundary would benefit the reliability or market needs to the southeast. Conversely, improvements located southeast of the bi-directional boundary would serve the reliability or market interest of loads located to the northwest. The economic benefits are mutual, since increased capability in either direction permits some greater measure of price-based transactions to proceed without constraint. This updated Section 2.5 provides a review of terms and quantitative updates to the charts and graphs that appeared in the original 2000 plan's Section 3.3.2.

The ability to transfer power from numerous source points, known as Points of Receipt (POR), to sink points, known as Points of Delivery (POD), depends on the relative impact that the resulting power flow has upon key defined interfaces, known within MAPP as flowgates. A flowgate is defined as one or more elements that act as a proxy for an operating security limit. An operating security limit can be determined by transient or voltage stability, unacceptable voltage levels or thermal restrictions, whichever is most limiting. Flowgates have been identified for known system "bottlenecks" which limit power transfer. These flowgates are used for both granting transmission service and for monitoring real-time system conditions to assess security. Flowgates are also used to identify schedule curtailments when Transmission Loading Relief (TLR) is needed. Eighteen of the major MAPP flowgates are described in Table 2.5-1, and twelve are illustrated on Figure 2.5-1.

Table 2.5-1. Names for Interface

Abbreviation	Expanded Meaning	Comment
COOPER_S	Cooper South Transmission Interface	Located in southeast Nebraska
ECL-ARP	Eau Claire to Arpin	Between city of Eau Claire WI, and a key substation "Arpin" to the east
FTCAL_S	Fort Calhoun South	Power flow south out of Fort Calhoun plant
GGS	Gerald Gentleman Station	Power flow east and south from GGS
GRIS_LNC	Grand Island to Lincoln	
LACYGNE_N	Lacygne North	Power flow North from the Lacygne Generation in Missouri
MH_SPC_W	Manitoba Hydro to Saskatchewan	Tie lines between the two providers
MHEX N	Manitoba Hydro Export North	Stability interface. Power flow from the south into Manitoba
MHEX_S	Manitoba Hydro Export South	Stability interface. Power flow out of Manitoba to the south
MNEX	Minnesota Export	
MNTZUMA_W	Montezuma West	Power flow from Montezuma to Bondurant 161 kV line in Iowa
NDDC	North Dakota Direct Current	Power flow into North Dakota AC system from plants (Coal Creek and Young 2) that are normally scheduled over DC lines
NDEX	North Dakota Export	Stability interface located in the Dakotas
NI_WUMS	Northern Illinois to Wisconsin Upper Michigan Systems	
PRI-BYN	Prairie Island to Byron	345 kV line
QUADCITY_W	Quad City West	Power flowing West out of the Quad City Substation at Illinois/Iowa border
WNE_WKS	Western Nebraska-Western Kansas Transmission Interface	
Y2DC	Young 2 Direct Current	Power flow into the North Dakota AC system from the Young 2 Unit only

Note: Some of these abbreviations are illustrated in Figure 2.5-1, and the transmission lines that make up each can be viewed at the OASIS Information page by clicking on the item "MAPP Flowgates" at **http://toinfo.oasis.mapp.org/oasisinfo/**.

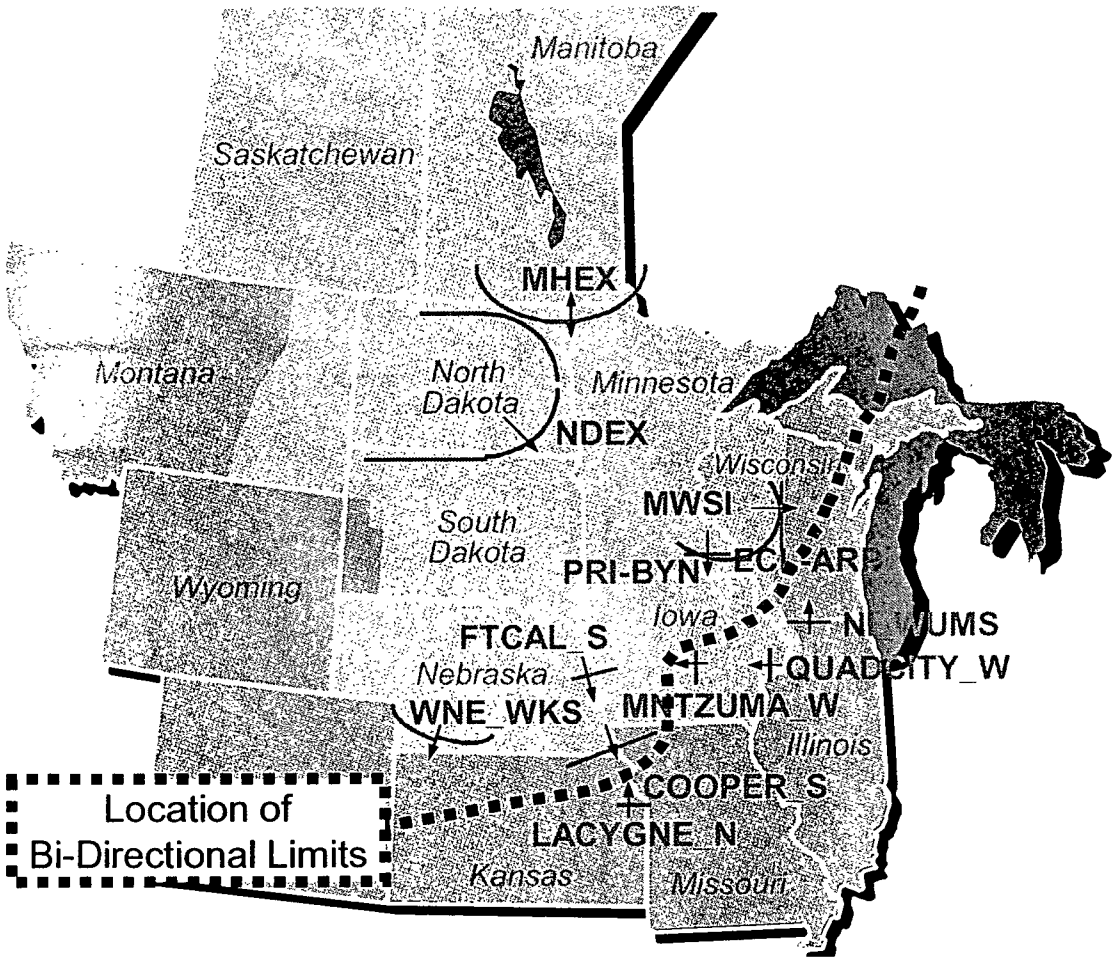


Figure 2.5-1. Interface Names and Locations

Since operation of the MAPP OASIS began in 1997, various data base records have been collected. The updates in this section are based on historical TLR and OASIS Refusals through 4/1/2001. Review of refused Firm Transactions, refused Non-Firm Transactions, and subsequent curtailments of approved schedules reveals much about why transmission limits occur. Locations are identified directly through curtailments and from the history of OASIS service refusals on the MAPP system. In addition, MAPP's electronic scheduling process enables study of after the fact schedules. Analysis of this information reveals the limitations on the system and suggests that new transmission expansion may be needed.

In order to measure the impact of both the varying megawatt size and duration of transactions, megawatt days are used as the common measuring unit to review service refusals. Since curtailments are implemented upon actual schedules associated with reservations, the study of curtailments can be refined to use megawatt hours as the unit of measurement. Another method of tracking limitations is the count of refused reservations or curtailments. The following Sections 2.5.1 through 2.5.3 will cover the review of Curtailments, Refusal of Firm requests, and

Refusal of Non-Firm requests. Figure 2.5-2 is a diagram that illustrates the relationship of various processes in the overall congestion management effort. The curtailments are in the center of the yellow portion of the diagram and the flow-based evaluations of requests that lead to approval or refusal are at the right side of the orange portion. The green area represents the role of expanding the transmission system. Properly identified expansion will ease stress on the processes to the right in Figure 2.5-2.

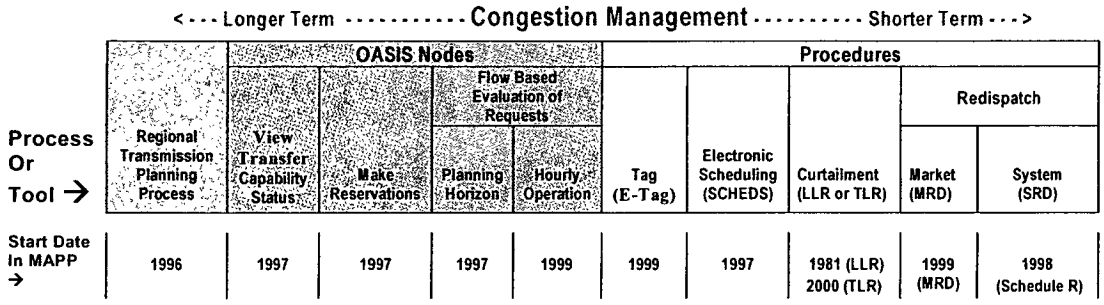


Figure 2.5-2. System Security Phases

The remaining portion in Figure 2.5-2 focuses on summarizing the degree to which the processes to the right are being utilized. This sort of quantification is necessary in order to determine if new facility construction is a strong candidate for sustaining reliability or if further perfecting the other processes are more feasible. This approach is most useful to evaluate the need for additional facilities that enable use of point-to-point transmission service. Other types of analysis are better for quantifying service to native load.

Market participants are active over the range of activities illustrated in Figure 2.5-2. This usually starts with the OASIS phase where service requests are made in the Planning Horizon (requests for 36 hours or greater in advance) or in the Operating Horizon (requests that are up to 36 hours in advance) and then proceeds through the Tagging, Scheduling and Curtailment phases. The average monthly energy associated with the three key transmission service phases are shown in Figure 2.5-3. In the reservation phase, the "would have been" energy from refused Firm requests is shown to be a major contributor to the approved Non-Firm requests. Next, the approved portions of all Firm, Reserved Non-Firm, and Non-Firm requests transition to the scheduling phase, and ultimately a small portion becomes curtailed. During 1999 through mid-2001, curtailed Non-Firm energy equaled about 0.55% of all scheduled energy. The amount of curtailed Firm was negligible at 0.015% of all scheduled energy (see the red numerals in Figure 2.5-3).

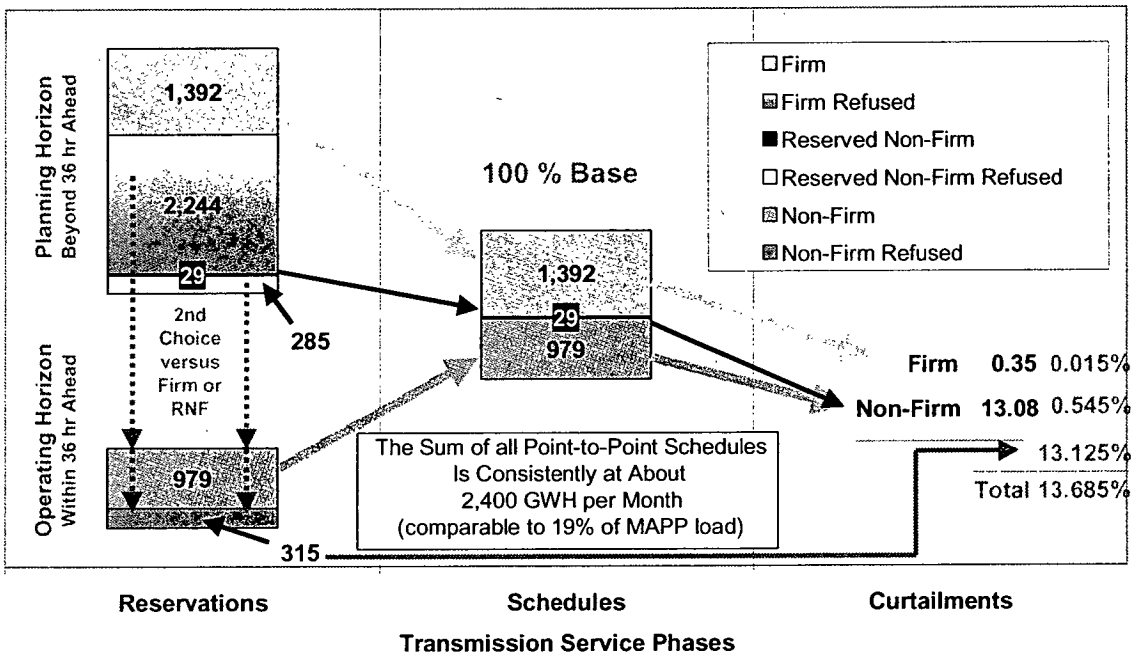


Figure 2.5-3. Average Distribution of Energy Associated with Point-to-Point Service (GWH per Month)

Because the transmission system is highly reliable, measuring the need for improvement can be challenging. Analysis of data from 1/1/1999 through 4/1/2001 reveals that an average of only 0.56% of all Point-to-Point schedules were curtailed. The red numbers in Figure 2.5-3 indicate that both transmission reservation refusals and schedule curtailments contribute to congestion management. The 0.56% is the sum of curtailed recallable and non-recallable schedules compared to 13.12% that is derived from refused reservation requests. The curtailment level of 0.56% is down from the 2% level reported in the original 2000 report that was based on data only through 1999. The congestion management summary in Figure 2.5-6 illustrates how the daily curtailments and refused reservation requests occurred over the period. Much like transmission line outage events or failure of very reliable power plant components, the rare

occurrence of curtailments often provides a scarce amount of data. The scarcity of this data can raise questions about statistical significance. However, tracking refused transmission service requests provides a more statistically significant source for seeking out transmission limitations. The volume of refused service records offers 400 times the information base upon which to study, than that that is available from historical curtailment records.

2.5.1 History of Curtailments

The curtailment history since 1997, along with the transition from MAPP Line Loading Relief (LLR) to NERC's Transmission Loading Relief (TLR), is illustrated in Figure 2.5-4. Figure 2.5-4 indicates that the trend based on actual number of curtailment logs increased with the transition to TLR in mid 2000. Investigation has shown clearly that only the count of TLR's that involve a MAPP Schedule have increased, and the actual amount of curtailed energy has continued to decrease through mid 2001. The result of transitioning to the NERC TLR is that a few MAPP Schedules are impacted more often, but the total effect on the energy schedules in MAPP continues to decline. Most of the decreased curtailments for Non-firm service are attributed to the MAPP request evaluation of Non-firm service starting in April 1999. This evaluation process refuses many Non-firm requests and pre-empts them from being curtailed under conditions where it would be very likely that approving the service would have resulted in curtailment of the schedule. The decline in curtailments from 2% of scheduled energy to 0.56% of scheduled energy quantifies the updated impact on the energy schedules.

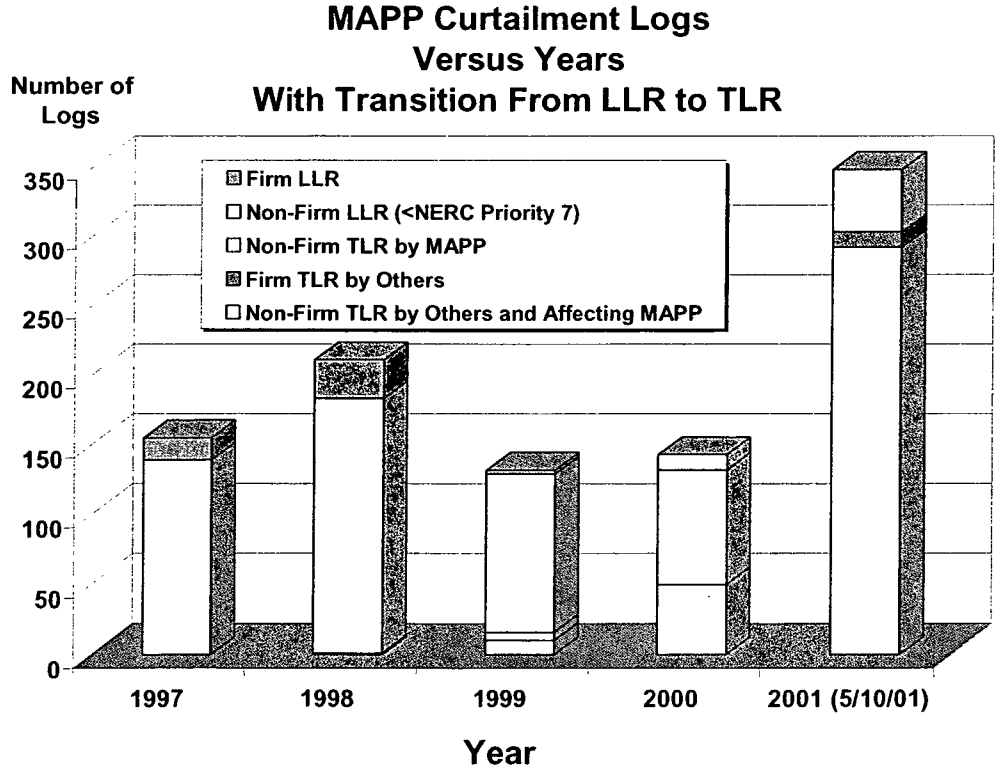


Figure 2.5-4. MAPP Curtailment Logs Versus Years With Transition From LLR to TLR

Figure 2.5-5 illustrates details by summarizing the curtailed energy for the April 1998 through April 2001 time period by the flowgate (or other facility) upon which relief was requested.

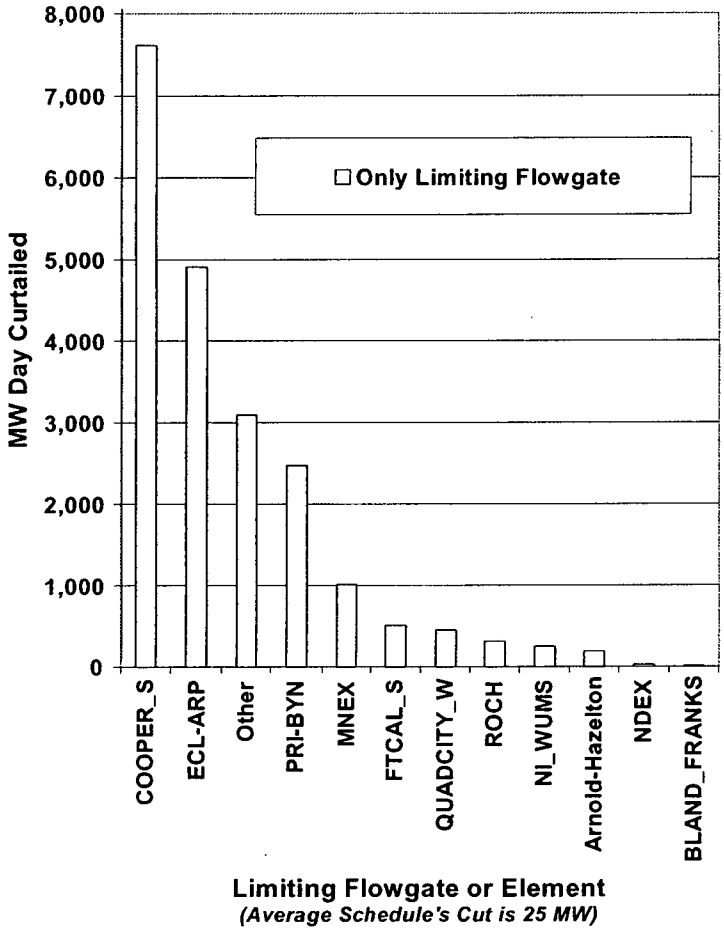
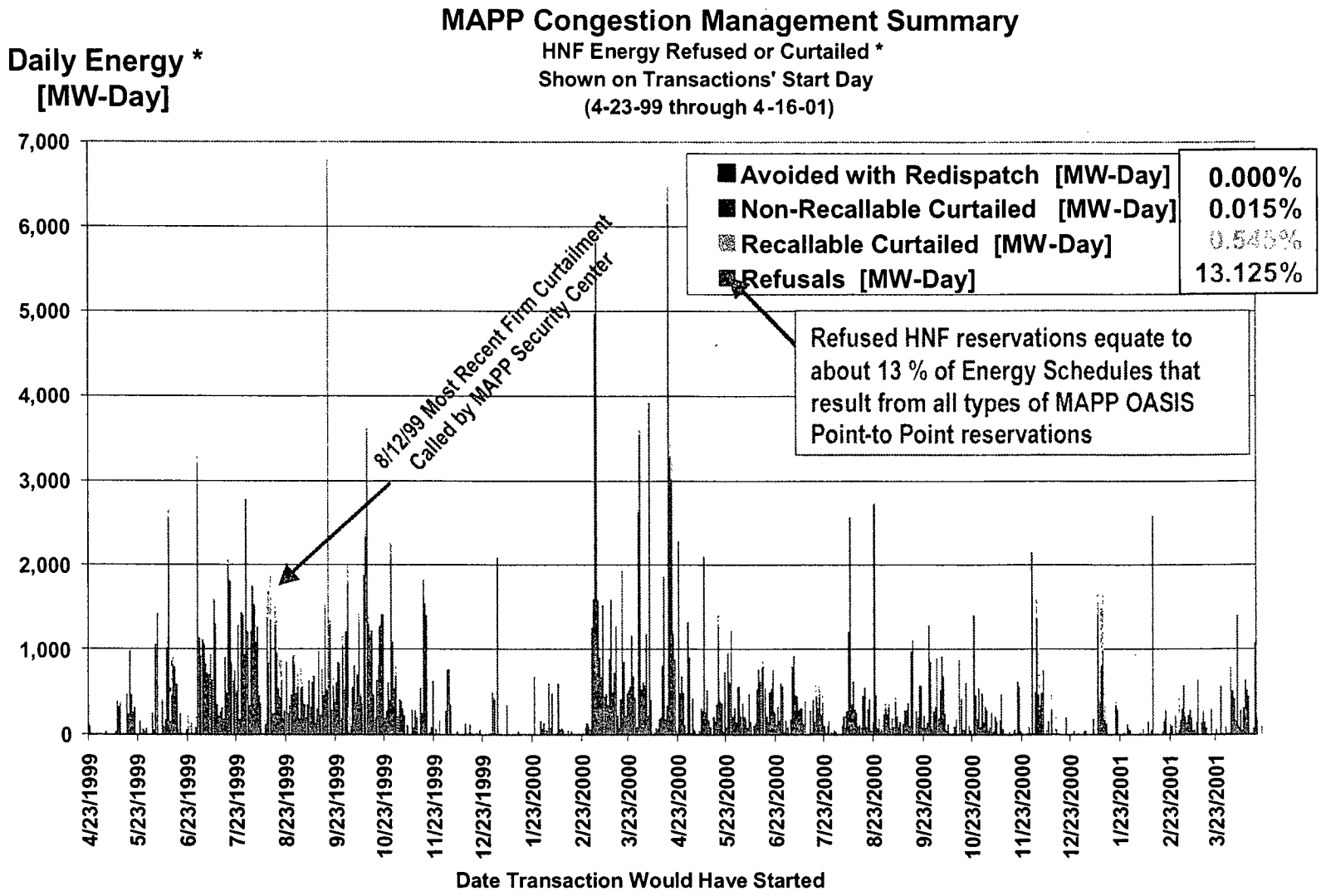


Figure 2.5-5. Firm and Non-Firm Schedule Curtailments (MW Day) (From 4-25-98 Through 4-16-01)

The additional data now shows that approximately 39 % (down from 48%) of the curtailments are due to COOPER_S and FTCAL_S, about 40% (up from 28 %) due to MAPP to MAIN related facilities and 15% (down from 22%) are due to the "other" category.

The next category of limitations shows transmission service refusals that have been individually evaluated on a flow-basis. Flow-based refusals provide another source of data similar to curtailments. The curtailment and refusal data was accumulated in the transmission system without the Arrowhead to Weston line in-service. The Arrowhead to Weston line constitutes the recognized expansion solution for dealing with the MAPP to MAIN limitations. Therefore, the 2000 Regional Plan and this 2001 update focus more on evaluating the level of need and alternatives for dealing with the MAPP to SPP limitations.

Most of the Congestion Management effort is being realized via the OASIS evaluation process by refusing requests during the Operating Horizon (from 1 to 36 hours into the future) versus after the fact curtailments or redispatch. The combined history of curtailments, OASIS Refusals, and redispatch are shown in Figure 2.5-6. The MAPP redispatch tariff is only applicable to Non-recallable schedules, and no redispatch has been warranted to date. Figure 2.5-6 displays the amount of recallable (Hourly Non-Firm [HNF]) and non-recallable energy curtailed from schedules that had started (blue portion of bar) versus the amount of energy schedules prevented from being initiated (red portion of bar) by refusing reservation requests. Figure 2.5-6 displays at the upper right side the daily sums and the percentages for the whole charted period (in font color corresponding to respective portion of bar). The percent values are the percent of all Point-to-Point (recallable + non-recallable) energy scheduled at the MAPP Security Center, and also correspond to the calculations that were illustrated in Figure 2.5-3.



* Energy Refused is based on the Segment with maximum MW times the Deal duration in days.

Figure 2.5-6 Congestion Management Summary

2.5.2 History of Firm Refusals

The number of Firm and Non-Firm transmission service requests and the refused portion is shown in red in Figure 2.5-7. The corresponding total energy associated with the approved point-to-point reservations has been relatively constant since January 1997. Since inception of the OASIS in 1997 the number of approved requests increased steadily. Most notable, the 2000 plan reported that the increase had appeared to level of, but this 2001 update reveals that the increase continues very strongly.

Since refusals have just recently (since the availability of the Cordova Generation) been significantly realized on the importing flowgates of LACYGNE_N, MNTZUMA_W, NI_WUMS, and QUADCITY_W, the impact on the total refusal assessments in Figure 2.5-7, Figure 2.5-8, and Figure 2.5-9 are small to date.

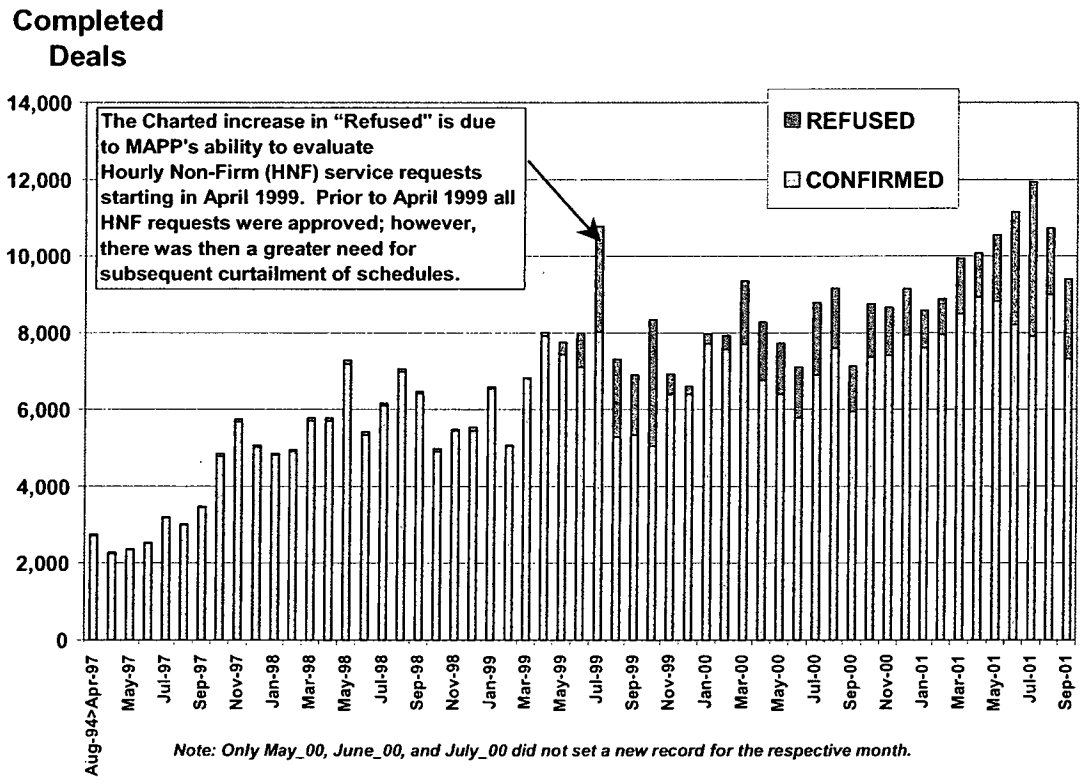


Figure 2.5-7. Volume of Point-to-Point Firm and Non-Firm Transmission Service

The Firm requests are fewer in number but they account for a majority of the scheduled energy (previously in Figure 2.5-3). This occurs because the nominal duration for a Firm request is about 4 (down from 6) months, versus 8 hours for a typical Non-Firm request. In order to correlate the scheduled energy associated with the Firm requests, a 34% load factor was applied to each MW Day of Firm reservation. This established the energy associated with Firm refusals in Figure 2.5-3. The MW Days associated with Non-Firm reservations are the actual requested

MWH, but divided by 24 and expressed in [MW Day] units. Therefore, no load factor was required to get the energy associated with the Non-Firm refusals. The energy associated with approved Firm or approved Non-Firm is the actual after-the-fact scheduled energy.

MAPP has performed flow-based evaluations of ATC on requests for Firm since 1997, and has done flow-based evaluations of Non-Firm since April 1999. The background work done for this report included the count and the MW Days of Firm and Non-Firm refusals.

Distribution of the refused Firm MW Days by MAPP constrained flowgate is shown in Figure 2.5-8. The "Only Limiting Flowgate" portion of the bar is the amount of business that was refused uniquely due to limiting flows on the respective flowgate. The "1 of 2" category is a flowgate's share of half of the refused service whenever that flowgate and one other flowgate contributed to the limit. Similarly, the "1 of 3" and "1 of 4" are when the refusal is split among three or four constrained flowgates. The sum of the constrained Firm business for the period 4/3/97 through 6/13/01 is 12,359,406 MW Days (up from the aggregate of 3,315,525 MW Days previously refused through 1/25/00).

When compared to the curtailments in Figure 2.5-5, the predominance of "COOPER_S" as a constraint is not sustained for the Firm refusals in Figure 2.5-8. However as a group, the two major MAPP to SPP flowgates (COOPER_S+FTCAL_S) account for 31% (up from 29%) of the Firm MW Days refused, and the MAPP to MAIN related flowgates (MNEX+ECL-ARP) accounted for 41% (down from 55%). Second to the MAPP to MAIN restrictions affecting the MAPP area (where the Arrowhead-Weston line is planned), the MAPP to SPP limitations are the most constrained portion of the system.

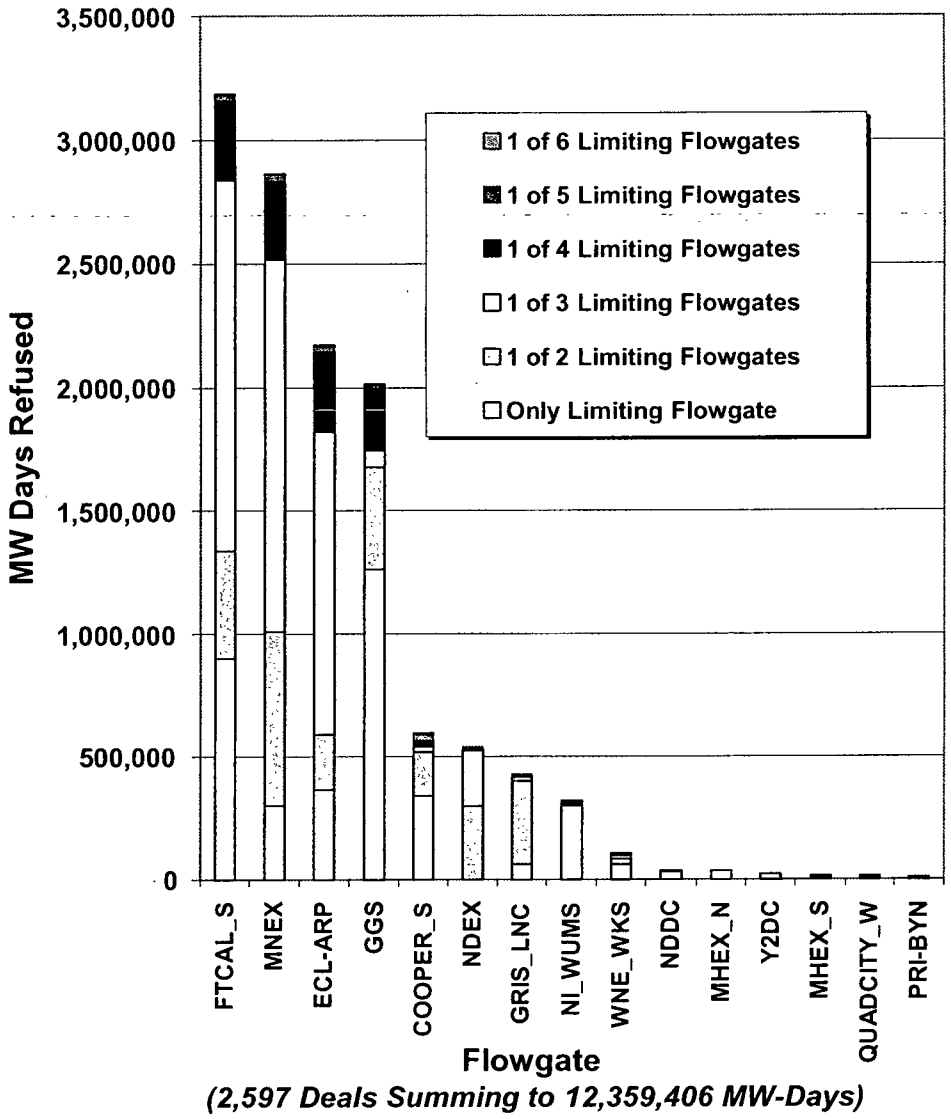


Figure 2.5-8. Refused Service Firm Capacity Transmission Service (FCTS) (From 4-3-97 through 6-13-01)

2.5.3 History of Non-Firm Refusals

Review of Non-Firm refusals is shown in Figure 2.5-9. The two major MAPP to SPP flowgates (COOPER_S + FTCAL_S) account for about 40% (up from 36%) of the total refused 330,562 MW Days, and the MAPP to MAIN group (MNEX or new MWSI + ECL-ARP + PRI-BYN) accounts for about 40% (same as the 2000 report) of the total refused 330,562 MW Days. Unlike the distribution of MWH curtailments in Figure 2.5-5 where COOPER_S was the predominant flowgate for curtailments, FTCAL_S is predominant for Non-Firm refusals. The sample of 330,562 MW Days refused for Non-Firm through 6/2/01 (up from the total of 138,656 MW Days previously refused through 1/21/00) is small when compared to the 12,359,406 MW Days of Firm refusals through 6/13/01 (Figure 2.5-9 versus Figure 2.5-8).

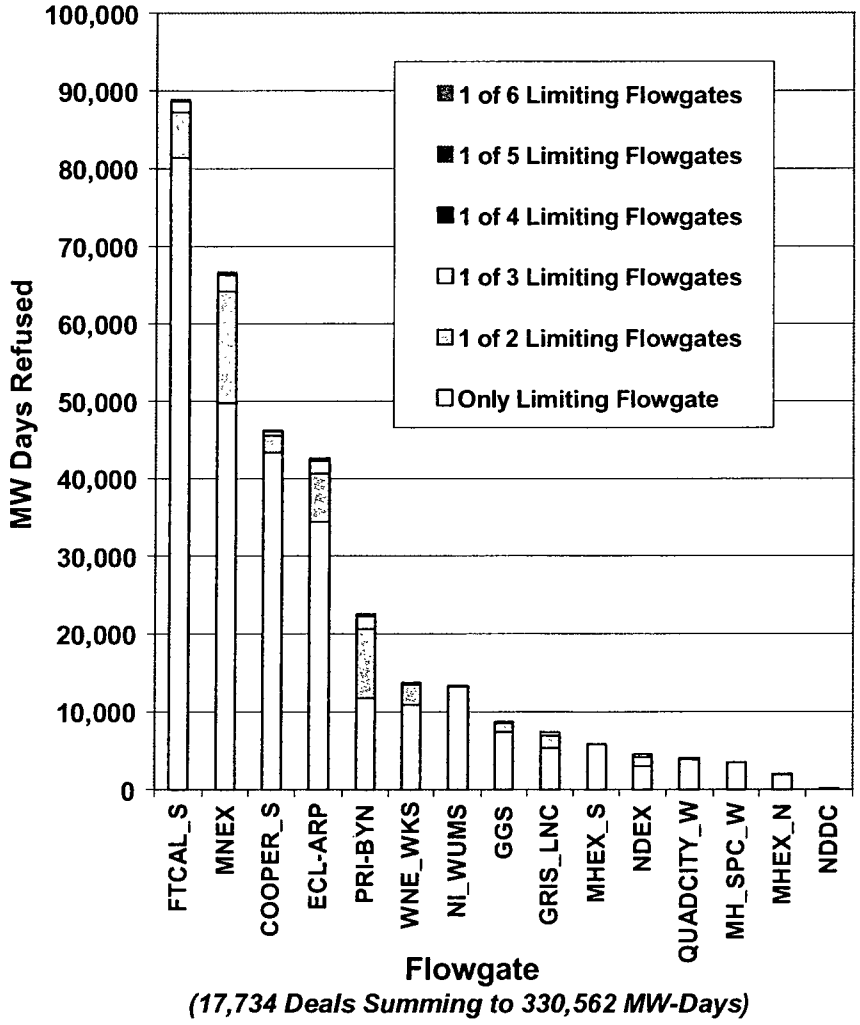


Figure 2.5-9. Refused Service Hourly Non-Firm (HNF) (From 4-23-99 through 6-2-01)

Section 3. SPG Summaries

The SPG facility updates are shown on the TPSC Forms 1-5, and are included in Appendix A. Additions or changes to Forms 1-3, and Form 5 are shown in red (gray for black-and-white print). Changes to the Regional Plan Map (Form 4) are qualified with a variation in color, and selective shading of cells in Map Legend Tables for lines and generators. The SPG update reports follow:

3.1 Iowa Transmission Working Group

3.1.1 Executive Summary

The Iowa Transmission Working Group (ITWG) generally covers the transmission facilities located within the State of Iowa. The Member participants of the ITWG are:

- Alliant Energy
- Cedar Falls Municipal Utilities
- Central Iowa Power Cooperative
- Corn Belt Power Cooperative
- Iowa Association of Municipal Utilities
- MidAmerican Energy Company
- Muscatine Power and Water
- Northwest Iowa Power Cooperative
- Western Area Power Administration

3.1.2 ITWG Subgroups

Wind Generation Subgroup

By the end of 2001, 80 MW (nameplate rating) of wind generation will be added in Iowa. This brings the total wind generation to approximately 325 MW in Iowa.

Marshalltown to Grand Junction 115 kV Subgroup

The 115 kV system described in this section stretches about 75 miles from the Grand Junction 161/115 kV substation on the west to the Marshalltown 161/115 kV substation on the east. A third 161/115 kV source, Boone Junction, is located approximately 1/3 of the distance from Grand Junction to Marshalltown.

The Grand Junction to Boone 115 kV line is owned by CIPCO, but operated by ALTW. This approximate 20-mile section has been reconstructed to 161 kV specifications, but is still operated at 115 kV. It uses T2-397 conductor and has a top rating of 206 MVA. A 161/115 kV, 50 MVA

autotransformer located at Grand Junction limits the rating of the Grand Junction to Boone 115 kV line to 50 MVA.

The Boone-Boone Junction-Ames-Fernald-Marshalltown lines are owned and operated by ALTW. This approximate 55 mile section of line is constructed and operated at 115 kV, uses 4/0 ACSR conductor, and has a top rating of 68 MVA. The largest single line section of this 115 kV system stretches nearly 31 miles from Marshalltown to Fernald.

Various contingencies on this 115 kV system cause overloads and low voltages in future models. Also, some 161 kV contingencies in the surrounding area can cause overloading of the 115 kV system. The problems associated with this area of the system have been identified long ago, and have been discussed in prior ITWG plans.

Detailed studies of the 115 kV system were placed on hold pending the completion of a 34.5 to 69 kV conversion study in the area that is served by the 115 kV system. The results of the subtransmission study identify the need for a new 69 kV source, tentatively called Huxley Substation, to be located on CIPCO's Boone Junction to Bondurant 161 kV line.

Studies to date indicate that the addition of the Huxley Substation source should reduce the contingency loading on the area 115 kV system, and could potentially delay the need for conversion to 161 kV. In addition, a future capacitor bank installation at the Ames 115 kV Substation appears to support low voltages that can occur during area contingencies.

Studies in this area have not been completed to date, but are continuing. In parallel with the study work, ALTW is assessing the physical condition of the aging 115 kV lines to determine when reconstruction will be the most economical from a physical point of view. The decision to rebuild the 115 kV lines and convert them to 161 kV will be made after the electrical studies and physical assessment are completed.

Marshalltown to Iowa Falls 115 kV Line Section

Marshalltown-Wellsburg-Eldora-Iowa Falls-Franklin 115 kV line is owned by ALTW. These lines are 266 MCM conductor with a top rating of 92 MVA. Violations have been identified and become more frequent in future years. The violations are overloads on the above-described sections of line due mainly to excessive var loading. ALTW has determined several system upgrades for the Iowa Falls and Wellsburg systems. Much of the 34.5 kV system in the Iowa Falls and Wellsburg area are being converted to 69 kV over the next 10 years. Along with the upgrades, some of the load will be transferred to Hampton and Fernald. ALTW is also adding a 115 kV, 14.4 MVAR capacitor bank at Wellsburg and two 115 kV, 14.4 MVAR banks at Iowa Falls in 2002.

Northwest Iowa Transmission Study Subgroup

The subgroup has initiated another study. Currently the group is in the process of model development. The model will be ready for study work this fall (2001).

Clinton Area Subgroup

The Clinton Iowa area transmission system has been recognized by ALTW as an area in need of review. The loading in this area, coupled with system transfers across Iowa to MAIN, can cause system violations. The Clinton Area Transmission Study will determine needed upgrades to the area transmission system to maintain system reliability and security.

Western Iowa Subgroup

Results from the contingency screening study indicate that overloads or undervoltages of lower voltage elements occur in the Denison, Creston, Eagle, and Spencer areas for single contingency outages of certain 230 and 161 kV elements. An outage of one 230/69 kV Eagle transformer results in overloading of the parallel unit. Similarly, an outage of one Denison or Spencer 161/69 kV transformer results in an overload of the second 50 MVA unit.

Several options exist to relieve the overloads, among them are to add transformer capacity at Denison and Eagle. WAPA is planning transformation additions in the Denison area budgeted for installation in 2003. NIPCO and MEC are jointly planning expansion of the Eagle substation by adding a new transformer in 2001.

Another alternative is to increase the area load serving capability with a tap of an existing line. Capacitor additions at various locations in the area, and several 69 kV line additions have been proposed in the Northwest Iowa Transmission Study completed in 1997. Sectionalizing the 69 kV system will eliminate transformer overloads and voltage violations at Denison and Creston. Continued analysis of this area along with operational procedures and future facility plans will be monitor with the affected utilities of both the Iowa Transmission Working Group SPG and the Missouri Basin SPG. No additional facilities besides the transformation additions at Denison and Eagle are recommended at this time.

New Renewable Resource Study Subgroup

This group will look at what additional transmission facilities would be needed to accommodate additional renewable resource generation in north and western Iowa.

3.1.3 Iowa Constrained Interfaces and Operating Guides

Two constrained interfaces have been defined in Iowa due to heavy bulk power transfers from MAIN to MAPP and SPP. The Quad Cities West flowgate (6081) was defined in May of 2001, and the Poweshiek – Reasnor flowgate (3704) was defined in July 2001.

The Quad Cities West flowgate was established to prevent overloads on the Quad Cities – Sub 91 345 kV line for the single contingent loss of the Cordova – East Moline (Sub 39) 345 kV line and East Moline 345/161 kV transformer.

The Montezuma – Bondurant Constrained Interface Temporary Operating Guide was established in July 2001 to prevent post-contingency overloading of the Poweshiek-Reasnor and Reasnor-

Des Moines 161 kV lines when flow on the Bondurant-Montezuma 345 kV line reaches or exceeds approximately 500 MW.

Westerns Denison transformer may be at risk of overload beyond emergency levels at certain pre-contingent load levels. Western has an operating guide to define load levels and responses. The 230/69 kV transformer additions at Denison should allow Western to remove the operating guide restrictions.

3.1.4 ITWG Transfer Analysis for Local Transmission Problems

The TPSC identified a list of potential transmission problems in the Iowa area for heavy transfer conditions in the 1998 MAPP Regional Plan. The ITWG was charged with reviewing the list and developing corrective actions or relevant explanations.

ALTW Lime Creek – Emery 161 kV line

This line was identified in the WIRE (Wisconsin Interface Reliability Enhancement) study as a potential limiting element. More analysis is necessary to verify if the line is actually a limiting element.

3.1.5 Description of Updates

Alliant Energy

Alliant Energy is planning the following changes:

Form 1 – Transmission Lines and Transformers

Twin Rivers to Viele 161 kV line

This project increases reliability in the Keokuk, IA region by constructing a 12.5 mile 161 kV line that will loop the existing radial 161 kV line that serves the area.

Grand Junction 2nd 161/115 kV Transformer

CIPCO's 45 MVA, 161/115 kV Dundee transformer failed in June 2001. This unit will be rebuilt and relocated to the Grand Junction substation and placed in parallel with the existing 50 MVA, 161/115 kV transformer before the summer of 2002. The existing Grand Junction unit overloads often during peak load conditions, and adding the second unit will help alleviate this problem. The failed Dundee unit will be rebuilt to closely match the rating and impedance of the existing Grand Junction transformer. Alliant will be installing a larger 75 MVA transformer at Dundee to replace the failed unit.

Form 2 – Devices

Capacitor Banks at Wellsburg and Iowa Falls

One 14.4 MVAR 115 kV capacitor bank at Wellsburg and two 14.4 MVAR 115 kV capacitor banks at Iowa Falls are scheduled to be in service in 2002, as part of an overall load serving plan recently finished by ALTW. The Iowa Falls-Wellsburg 115 kV line can overload under certain conditions due to excessive var loading. The capacitors will solve this problem. As well, some of the loading from these two substations will be transferred to other substations not served by this 115 kV line.

50.4 MVAR Capacitor at Carbide Substation

This 161 kV capacitor bank is needed in the Keokuk area to help support voltages that result from certain contingencies.

40 MVAR Capacitor at DAEC

This capacitor is needed in part to offset a var capability reduction of the DAEC plant and to support the Cedar Rapids area for certain contingencies.

30 MVAR Capacitor at PCI

This capacitor is needed to support the Cedar Rapids area for certain contingencies.

30 MVAR Capacitor at Fairfax

This capacitor is needed to support the Cedar Rapids area for certain contingencies.

Form 3 – Generation

Duane Arnold Energy Center (DAEC) Uprate

Alliant Energy is uprating the DAEC Nuclear power plant near Cedar Rapids, Iowa in 2001. The uprate will raise the power plant output 65MW to 585MW/600MW, summer and winter respectively. A study has been submitted to the MAPP Design Review Subcommittee demonstrating that the upgrade has no negative impacts on the system and that the present transmission system is adequate, requiring no transmission additions.

Cedar Falls Municipal Utilities (CFU)

Cedar Falls is reporting the following generation addition:

Form 3 – Generation

Cedar Falls CT #2

Complete.

Iowa Association of Municipal Utilities (IAMU)

The Iowa Association of Municipal Utilities is reporting the following generation additions:

Form 3 – Generation

Waverly Diesel

Complete.

Resale Power Group of Iowa (RPGI)

Complete.

Pella

Pella will replace 4 MW of lease diesel generation with a total of 28 MW of diesel generation by summer 2002.

Harlan

Harlan will add two 1.75 MW Diesel Generating Units at Harlan, Iowa by July 2001.

All of the generation additions listed for the IAMU are small generating units that will be connected to the local distribution system. Little, if any, of this power will be exported from the local utility systems. Approval for the accreditation of this generation is being sought from the DRS. Their approval will signify that the generation additions will not be detrimental to the reliability of the bulk power system. In all cases, there is more than adequate capacity in the existing transmission systems to handle these generation additions.

Central Iowa Power Cooperative (CIPCO)

CIPCO is reporting the following changes:

Form 1 – Transmission Lines and Transformers

Grand Junction 2nd 161/115 kV Transformer

CIPCO's 45 MVA, 161/115 kV Dundee transformer failed in June 2001. This unit will be rebuilt and relocated to the Grand Junction substation and placed in parallel with the existing 50 MVA, 161/115 kV transformer before the summer of 2002. The existing Grand Junction unit overloads often during peak load conditions, and adding the second unit will help alleviate this problem. The failed Dundee unit will be rebuilt to closely match the rating and impedance of the existing Grand Junction transformer. Alliant will be installing a larger 75 MVA transformer at Dundee to replace the failed unit.

Form 3 – Generation

Member Municipal Systems

Several of CIPCO's member municipal systems are planning to install a total of 13 small diesel generators (2 MW each) at eight different cities in Iowa. The cities are Lenox, Dayton, Panora, Winterset, Greenfield, Brooklyn, Stuart, and Earlville. The small diesel additions planned at these cities are being added to serve municipal load. Normally, this municipal load is fed from the CIPCO transmission system. However, during the periods in which these diesel units run, some or all of the municipal load is served by the diesel generation, which releases capacity on the transmission system. The transmission system is therefore adequate to accommodate these diesel additions. These units have received DRS approval and are planned to be installed by the end of 2001.

Wilton

Wilton Municipal is adding two 2.2 MW units with an in-service date of June 2002.

Corn Belt Power Cooperative (CBPC)

CBPC is reporting the following changes:

Form 3 – Generation

Wisdom CT

CBPC and Basin Electric Power Cooperative plan to sign an ownership and operating agreement for an 80-megawatt natural gas/oil-fired combustion turbine scheduled to be built adjacent to CBPC's Wisdom Station. The design of the combustion turbine and

generator has been completed and will be ordered this fall. Necessary permits are being secured. Installation will begin by October 2003 with testing in the spring of 2004 and ready for commercial operation by June 2004.

MidAmerican Energy Company (MEC)

MEC is reporting the following changes:

Form 1 – Transmission Lines and Transformers

Ashawa to 100th & 54th Avenue 161 kV Line – In Service 6/1/00

MEC is planning to add approximately 15 miles of 161 kV line from Ashawa to 88th and from 88th to 100th & 54th Avenue substations in 2000 to serve load growth in West Des Moines.

MEC LeMars 161/69 kV Substation – In Service 10/1/01

Plans for a LeMars 3rd source, formerly the 69 kV K-211 line, have changed to a 161 kV source. MEC currently plans to construct approximately 11.2 miles of 161 kV line tapped from the existing Plymouth-Little Sioux 161 kV line to the southeast corner of LeMars and to add 161-69 kV transformation by 6/1/2001 to serve projected load increases.

345 kV Lines Rates Upgrade – In Service Fall 2001

MEC is planning to increase ratings on the 345 kV lines from Hills east to the Quad Cities Power Station (QCPS) and from QCPS to Sub 39 in anticipation of potentially heavy east-west 345 kV transfers. These upgrades should be complete by June of 2001 depending on material deliveries and outage schedules. The upgrades are as follows:

345 kV line	Old Summer Rating	Proposed Sum Rating	Status
Hills – Sub 92	937	1190	Complete
Sub 92 – Walcott	845	1195	Complete
Walcott – Sub 56(Davenport)	845	956	Complete
Sub 56 – Sub 91	937	956	Complete
Sub 91 – Quad Cities	968	1195	Complete
Quad Cities – Cordova	1000	1195	Complete
Cordova – Sub 39 (Moline)	1000	1129*	Not Complete

* Initial work on the Cordova – Sub 39 line work was completed to achieve 1129 MVA. Further work was delayed until the fall of 2001, when the rating will be upgraded to 1195 MVA.

MEC NE Ankeny – Alliant Jasper – Perry 161 kV Tap – In Service 6/01/03

MidAmerican plans to construct 1.0 miles of double-circuit 161 kV line from the Alliant Perry – Jasper 161 kV line to a new NE Ankeny switching station to serve load growth in the Ankeny area and to relieve potential single contingency overloads on the Sycamore – John Deere 69 kV line, the Sycamore – 2nd & Broadway 69 kV line, and the Sycamore 150 MVA 161-69 kV transformers.

MEC Ankeny – NE Ankeny 161 kV – In Service 6/01/03

MidAmerican plans to construct 6.0 miles of 161 kV line from the Ankeny to NE Ankeny to serve load growth in the Ankeny area and to relieve potential single contingency overloads on the Sycamore – John Deere 69 kV line, the Sycamore – 2nd & Broadway 69 kV line, and the Sycamore 150 MVA 161-69 kV transformers.

MEC Ankeny – Sycamore 161 kV – In Service 6/01/03

MidAmerican plans to construct 7.0 miles of 161 kV line from the Ankeny to Sycamore to serve load growth in the Ankeny area and to relieve potential single contingency overloads on the Sycamore – John Deere 69 kV line, the Sycamore – 2nd & Broadway 69 kV line, and the Sycamore 150 MVA 161-69 kV transformers.

Form 2 - Devices

161 kV 50 MVAR Capacitor Banks at Bondurant and Booneville – In Service 6/1/00

MEC plans to install one 50 MVAR 161 kV capacitor bank at Bondurant and one 50 MVAR capacitor bank at Booneville.

161 kV 50 MVAR Capacitor Banks at S.E. Polk and Forest & Vermont – In Service 12/31/00

MEC plans to install one 50 MVAR 161 kV capacitor bank at S.E. Polk and one 50 MVAR capacitor bank at Forest & Vermont.

Form 3 – Generation

Cordova Energy Center – In Service 6/1/01

Complete.

Indianola Generators – In Service 6/1/00

Complete.

MEC Des Moines Generators – In Service 6/1/00

Complete.

MidAmerican Diesel Generation – In Service 6/1/00

Complete.

Landfill Generation – In Service 6/1/00

Complete.

City of Ames Generation – In Service 6/1/00

Complete.

MEC Greater Des Moines Area Generator Center – In Service 6/01/03

MidAmerican Energy Company plans to develop and construct the Greater Des Moines Area Generation Center to be built on property the company owns just east of Des Moines, Iowa in Pleasant Hill. The facility will be a 610-megawatt combined cycle plant similar to the Cordova plant. Two combustion turbines should be in-service in 2003 and one heat recovery steam turbine should follow in 2005.

Adair County Combined Cycle Project – In Service 6/01/04

Entergy Corp. has proposed a 631 MW Combined-cycle plant near the town of Orient in Adair County. The facility will be a nominal 631-megawatt with two 171 MW natural gas combustion turbines and one 289 MW heat recovery steam turbine. The Adair County facility will be operated as a merchant plant by Entergy Power Generation Corporation to provide power to the grid under a competitive market environment and would be operational in 2004.

The proposed location of the Adair County 345 kV bus is close to the crossing of the Booneville-Cooper 345 kV line and the Madison County – Council Bluffs 345 kV line in southwest Iowa. The proposed 345 kV interconnection is a ring bus built directly adjacent to the Booneville-Cooper 345 kV line. The Madison-Council Bluffs 345 kV line, which passes approximately 1.5 miles from the new substation, will be looped into the Adair County substation. The substation will initially be operated as a ring bus but will be designed for conversion to breaker-and-a-half.

Muscatine Power and Water (MPW)

MPW is reporting the following changes:

Form 3 – Generation

Unit 8A Generator Addition

MPW's existing Unit 8 boiler was modified to provide up to 295,000 pounds of steam/hour to an industrial customer during the MAPP summer season and up to 370,000 pounds of steam/hour during the MAPP winter season. Unit 8A went commercial on July 1, 2000. This modification reduced the generating capacity of Unit 8 to 36 MW in the summer and 24.2 MW in the winter. Unit 8A has a summer generating rating of 16.3 MW and a winter generating rating of 18.4 MW. Unit 8A is a backpressure (non-condensing) turbine which receives steam from Unit 8's boiler. The exhaust steam from Unit 8A is used to heat the customer's feedwater. Since the project resulted in a reduction in capacity, additional transmission is not needed. The DRS approved this project.

Northwest Iowa Power Cooperative (NIPCO)

NIPCO is reporting the following changes:

Form 1 – Transmission Lines and Transformers

Eagle 230/69 kV Transformer – In Service 6/30/03

The in-service date was changed to 6/30/03.

Western Area Power Administration (WAPA)

WAPA is reporting the following changes:

Form 1 – Transmission Lines and Transformers

Spencer 161/69 kV Transformers - In Service 5/1/04

The existing Spencer transformers may become overloaded upon many contingencies, and loading in the area is increasing. Western, with the participation of area utility entities, is in the process of developing a detail model of the area in order to study transformation requirements. Current plans are to meet NERC reliability standards.

Denison 230/69 kV Transformers – In Service 5/1/03

Western is examining transformation at Denison. The model developed in the Spencer work above will be used to determine requirements for the Denison equipment. Current plans are to meet NERC reliability standards.

Form 2 – Devices

Capacitor Banks at Spencer, and Creston, IA - In Service 5/1/04
Capacitor Banks at Denison, IA - In Service 5/1/03

Western has seen operational problems at these substations on the high voltage buses. Western currently plans to place capacitors in service at each of these substations, in the 20 MVAR range. More detailed study work needs to be completed to determine exact sizing.

3.1.6 Future ITWG Tasks

The following are tasks that the ITWG will consider in the next 10-year plan:

1. 10-year review using the current series models.
2. Review future generation in the ITWG models.
3. Update multi-section contingencies for analysis.
4. Perform transfer capability studies.
5. Continue to consider results of other SPG studies.
6. Improve detail in models and correct modeling errors.
7. Include other subgroups and TPSC study work input.
8. Review and approve individual company's 10-year plans, if necessary.
9. Investigate constrained interface issues associated with system generation additions and the purchase of power.

3.2 Missouri Basin

3.2.1 Background

Every two years, the MAPP Transmission Planning Subcommittee (TPSC) completes a Regional Plan as part of the requirements under the MAPP Restated Agreement. The 2000 MAPP Regional Plan was finalized by the TPSC in December 2000.

The five existing Subregional Planning Groups (SPGs) each coordinate their plans with the TPSC and in the "off years" these plans are updated to reflect any new facilities not included in the Regional Transmission Plan. This report updates the Missouri Basin Subregional Planning Group's transmission plan.

Overview of the Missouri Basin Subregion and System

The Missouri Basin subregion of MAPP covers portions of Eastern Montana/Western North Dakota, Central North Dakota, Eastern North Dakota, Western South Dakota, and Eastern South Dakota. The map below shows the approximate area of each of the Subregional Planning Groups.

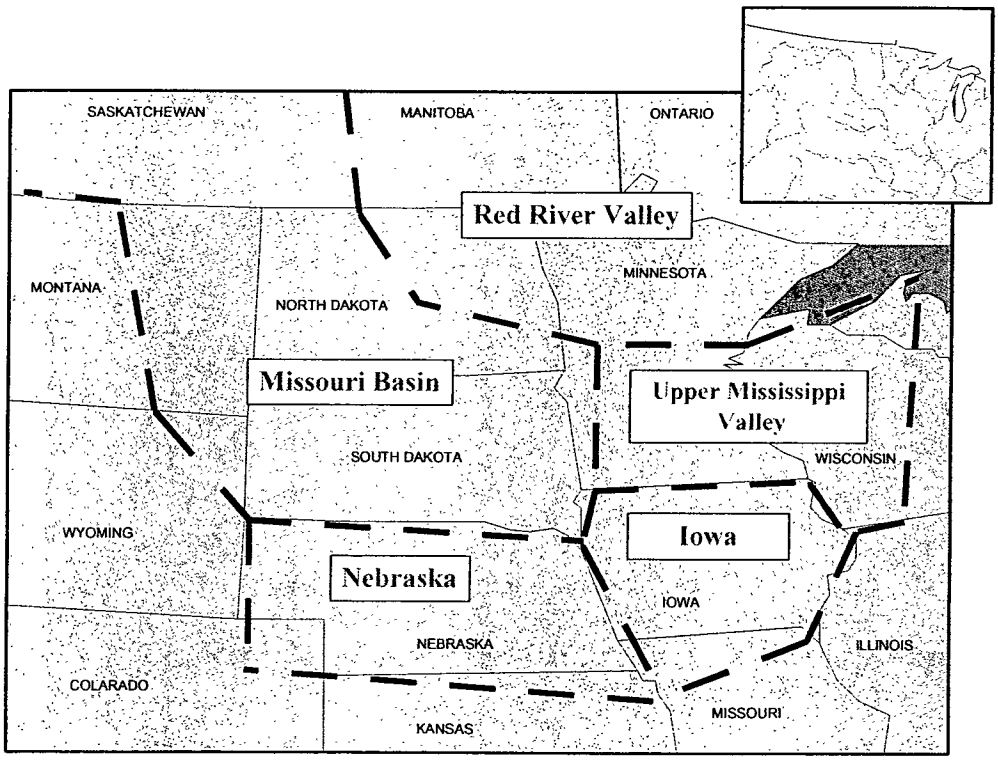


Figure 3.2-1. MAPP Sub-Regional Planning Areas

Participants in MBSPG

The following utilities own and/or operate transmission lines in the MBSPG subregion and participate in the MBSPG process:

- Basin Electric Power Cooperative (BEPC)
- East River Electric Power Cooperative (EREPC)
- Great River Energy (GRE)
- Heartland Consumers Power District (HCPD)
- Mid American Energy Company (MEC)
- Missouri River Energy Services (MRES)
- Montana Dakota Utilities (MDU)
- Northwestern Public Service Company (NWPS)
- Otter Tail Power Company (OTP)
- Western Area Power Administration (WAPA)
- Xcel Energy (XCEL)

3.2.2 Transmission Facilities

The following are transmission facility improvements presently planned in the MBSPG region. These facilities were not included in the December 29, 2000 Regional Plan but have since been proposed and are currently in the study or planning phase:

Tea Substation 230 kV Tap

East River Electric Power Cooperative is proposing a 230/69 kV substation south of Sioux Falls that will tap Western Area Power Administration's Sioux Falls-Utica Junction 230 kV line. This new substation near Tea, South Dakota is expected to be in service by 2003 and is primarily needed for load serving. Future conversion of 69 kV lines to 115 kV in the Sioux Falls area is under study and will be dependent on load growth.

Wolf Point-Williston 230 kV Upgrade

Western Area Power Administration is proceeding with upgrading the existing Wolf Point-Williston 115 kV line to 230 kV. This will be new 230 kV construction but the line will be operated at 115 kV. Future operation of the line at 230 kV will require replacement of transformers and the timing will depend on future area load growth.

Williston-Charlie Creek 230 kV Upgrade

Western Area Power Administration is proceeding with upgrading the existing Williston-Charlie Creek 115 kV line to 230 kV. This will be new 230 kV construction but the line will be operated at 115 kV. Future operation of the line at 230 kV will require replacement of transformers and the timing will depend on future area load growth.

Elk Creek Substation 115 kV Tap

Rushmore Electric Power Cooperative is proposing a 115/69 kV substation that will tap Western Area Power Administration's Rapid City to Newell 115 kV line. This new substation near Rapid City, South Dakota is expected to be in service by 2003 and is primarily needed for load serving.

3.2.3 Generation Facilities

The following are significant generation facilities that are proposed in the MBSPG region since completion of the Regional Plan in December of 2000.

Big Stone

Ottertail Power Company has received an interconnection request for a second unit at Bigstone in the 500-600 MW range. Ottertail is currently in the preliminary stages of study development.

ENXCO Wind Farm

ENXCO, Inc. is considering several wind farm development projects on the Buffalo Ridge area of South Dakota. These early development projects have well-defined sites with land under control, but have not been developed to the stage that they can be reported to MAPP for inclusion into the MAPP Models and the long-range plan because of known and existing transmission constraints.

ENXCO feels, however, that these projects are viable and will be developed in the near future because of utility interest and market demand. Because of that, ENXCO is taking this opportunity to introduce these projects so that they may receive some consideration in studies being conducted in this area. Wind generation has a relatively short lead-time for construction once the transmission work has been completed. Accordingly, ENXCO feels that it would not be appropriate to wait until next year to introduce these projects. The projects are:

Project Area	MW	Connected To	Coming on Line
Watertown	250	Watertown 230 kV substation	2004
Summit	40	Summit 115 kV substation	2002
Toronto	150	Watertown to Brookings 115 kV line	2003
White	150	White 115 kV substation	2003

Glendive

MDU will be adding a 40 MW combustion turbine near Glendive, Montana within the next three year timeframe.

Lignite Vision 21

Great River Energy and Montana Dakota Utilities/Westmoreland Power are considering two separate coal-fired units in North Dakota. Great River Energy is in the initial stages of study and a site is not yet known. MDU/Westmoreland has initiated a market study for a power plant in Southwestern North Dakota. Transmission requirements are too preliminary to report. The transmission studies may possibly be run jointly, but with two separate plant locations. The plants are being proposed to be in service by the 2007-2008 timeframe.

Watertown

Missouri River Energy Services (MRES) will be installing 150 MW of combustion turbines at its existing Watertown Power Plant. It is anticipated the first unit(s) will be installed by May 1, 2004. Following units will be installed between 2006 and 2008. MRES intends to include this generation as a Designated Network Resource.

3.2.4 Planning Studies

A number of planning studies are underway in the MBSPG region. Some of the studies are being required as a result of OASIS requests for transmission service. The following is a list of studies currently being conducted:

Transmission Expansion Study – Western Area Power Administration

Study to examine transmission requirements for wind generation at Jamestown, N.D. and Ft. Thompson, S.D.

Southwestern Minnesota Area Transmission Study – Xcel Energy

Study to examine outlet transmission for the next 400 MW of wind generation on the Minnesota/South Dakota portion of the Buffalo Ridge.

Northwest Iowa Transmission Study

Study to examine Northwest Iowa area problems due to load growth.

3.2.5 TPSC Forms

Updated TPSC Forms 1 – 5 identifying planned improvements for the region.

3.3 Nebraska

The Nebraska Subregional Planning Group (SPG) was formed in 1997. The primary objective of the Nebraska SPG is to develop a ten-year subregional transmission plan for the Nebraska subregional area. The Nebraska subregional area consists of the transmission networks encompassing the entire state of Nebraska and the adjacent networks in Northwest Missouri and portions of Northern and Western Kansas. The core members of the Nebraska SPG consist primarily of the regional entities with vested interest in the future development of the Nebraska SPG regional transmission system. Those entities are:

- Lincoln Electric System (LES)
- Municipal Energy Agency of Nebraska (MEAN)
- Nebraska Public Power District (NPPD)
- Omaha Public Power District (OPPD)
- Tri-State G & T Association (TSGT)
- St. Joseph Light & Power (SJLP)
- Kansas City Power & Light (KCPL)
- UtiliCorp United Incorporated (UUI)
- Sunflower Electric Power Corporation (SECI)

It is the responsibility of the Nebraska Subregional Planning Group (SPG) to provide updates and modifications to the SPG Plan between biennial planning year cycles and submit those modifications to the MAPP TPSC for approval. The Nebraska Subregional Planning Group (SPG) submits the following information as an update to the Nebraska Subregional Plan. Following is a summary of the Nebraska SPG modifications:

3.3.1 Form 1 – Transmission Lines and Transformers:

1) All new facility construction and existing facility upgrades planned for 2000 year in-service have been completed.

2) The Gentleman 345/230 kV second transformer addition and 345 kV substation expansion project is also complete.

3) The in-service dates for several transmission line projects have been modified and are shown in the attached Form 1 in Appendix A.

4) The Kansas City area projects involving a 345 kV line from Iatan – Nashua and a Nashua 345/161 kV transformer have been withdrawn from the SPG plan.

5) All other planned facilities and in-service dates are currently valid.

6) The following new transmission facility additions should be added to the Nebraska SPG Plan and integrated into the MAPP Regional Plan:

Facility	Addition	Area	Date
Bucyrus – North Louisburg	161 kV new transmission line	KCPL	1/1/2002
Beverly – Red Willow	115 kV substation upgrades	NPPD	2/1/2002
Beverly – Enders	115 kV substation upgrades	NPPD	2/1/2002
Duncan Road – Blue Springs	161 kV transmission upgrade	UUI	12/31/2002
Blue Springs – Prairie Lee	161 kV transmission upgrade	UUI	12/31/2002
Sub 3740 – Sub 3455	345 kV new transmission line	OPPD	5/1/2003
Sub 3740 – Sub 3458	345 kV new transmission line	OPPD	5/1/2003
19th & Alvo – NW 12th & Arbor	115 kV new transmission	LES	6/1/2003
84th & Bluff – 84th & Fletcher	115 kV new transmission line	LES	6/1/2003
Blue Valley – Crosstown	161 kV new transmission line	KCPL	6/1/2003
Stilwell – Antioch	161 kV new transmission line	KCPL	6/1/2003
Crooked Creek	230/115 kV substation and transformer	NPPD	6/1/2004
Crooked Creek – Broken Bow	115 kV new transmission line	NPPD	6/1/2004
Antioch – Oxford	161 kV new transmission line	KCPL	6/1/2004
Wagener – NW 68th & Holdrege	345 kV transmission line	LES	6/1/2005
Sub 3453 – Sub 1253	345/161 kV new transformer	OPPD	6/1/2005
Russell – Smith Center	230 kV new transmission line	UUI	12/31/2006
NW 68th & Holdrege	345/115 kV new transformer	LES	6/1/2006

3.3.2 Form 2 – Devices

1) All of the Capacitor bank additions planned for 2000 and 2001 in-service are completed.
2) The following new devices should be added to the Nebraska SPG Plan:

Facility	Area	MVAR Capacitor Bank	Date
Sub 942	OPPD	30	1/1/02
Olathe Substation	KCPL	50	6/1/2003

3.3.3 Form 3 – Generating Units

1) All of the generating units planned for 2000 in-service date are complete.
2) Rokeby Unit #3 and the Aries plant are also complete.
3) The Iatan Unit #2 project has been withdrawn.

4) The following generating units should be added to the Nebraska SPG Plan:

Facility	Area	MW	Date
GCW Wind Farm	UUI	110	12/1/2001
Alliance Diesel Generators	MEAN	5.4	1/1/2002
DCLFG Units 1-4	OPPD	3.2	6/1/2002
Paola CT Units 1-3	KCPL	231	6/1/2003
Fremont CT	FRET	50	6/1/2003
Grand Island CT's	GRIS	80	5/1/2004
Beatrice CC	NPPD	229	6/1/2005
Sand Sage Unit #1	SECI	600	6/1/2005
Hastings Energy Center Unit #2	MEAN	200	6/1/2007
Cass County Unit #3	OPPD	160	6/1/2009

3.4 Red River Valley

3.4.1 Background

The *MAPP Red River Valley Transmission Plan 2000-2009* identifies planned system improvements that serve to meet regional and inter-regional reliability and market requirements. This report also describes planning studies that are in progress at this time. In an effort to provide continuity between biennial planning cycles and periodic review of the regional transmission plan, in light of actual system development, an update to this plan is made on each off year of the biennial planning cycle.

In order to provide an update to this plan, this report addresses the following:

- Provides an overview of the Red River Valley Subregion, and System as a convenience to the reader.
- Identifies participants of the RRVSPG planning process.
- Describes RRVSPG initiatives to improve the regional planning process.
- Provides a near term assessment based on the results of automatic contingency screening analysis.
- Provides a progress update for planned improvements describing the latest topology and design; obstacles to implementation; milestones reached in the permitting process; MAPP approvals and pending requirements; and projected in-service dates.
- Identifies significant generation interconnection requests.
- Discusses in progress planning studies.
- Provides updates to the TPSC reporting Forms 1 – 5.

Overview of the Red River Valley Subregion and System

The RRV subregion of MAPP covers approximately north and central North Dakota; and north Minnesota surrounded by Lake Superior to the east; and it includes the entire Province of Manitoba to the Hudson Bay in the north as shown in Figure 3.4-1.

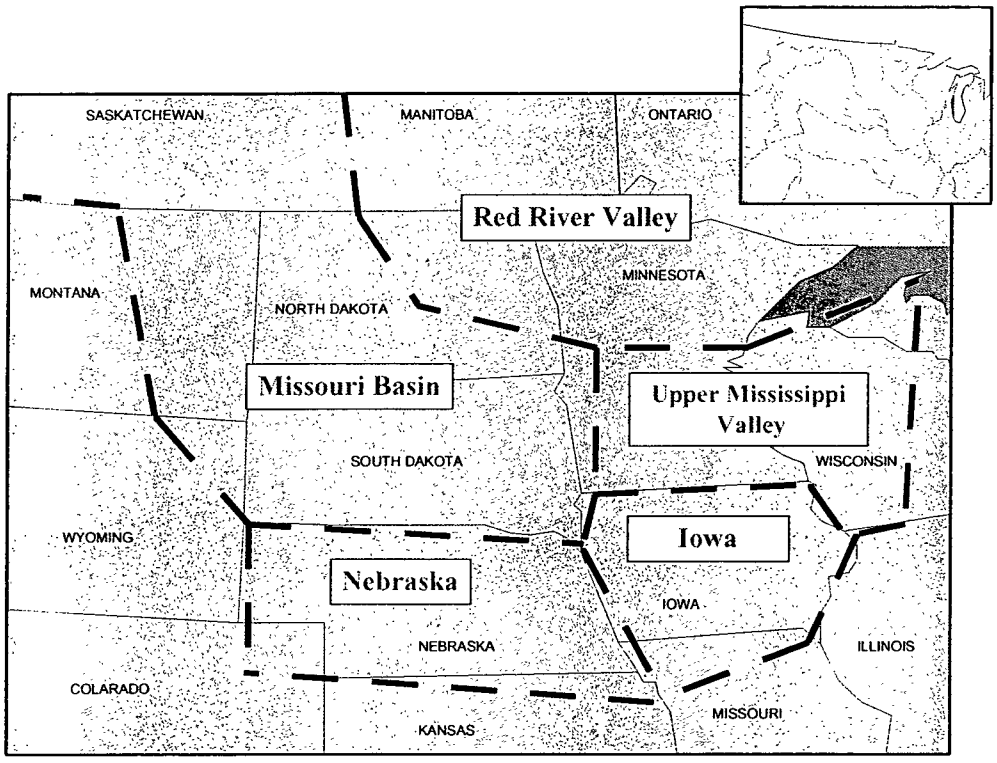


Figure 3.4-1. MAPP Sub-Regional Planning Areas

Bulk energy is delivered to the RRV subtransmission by 230 kV and 345 kV transmission systems. A single 345 kV circuit supplies the RRV region, the Center – Jamestown – Maple River Line. This line extends from the North Dakota Coal Fields to the approximate center of the region. Interconnected 230 kV transmission lines form the 230 kV system and originate essentially from generation centers to the North, South, West and East. The 230 kV lines that form the MHEX Interface deliver energy from the North. From the South, generation resources are available from the Twin Cities area, Minnesota Valley, and Big Stone. From the East, generation resources are available mainly from Boswell. North Dakota plants located in the coal fields provide Western resources. Subtransmission at 115 kV and below delivers energy to load centers scattered throughout the region having low to moderate load densities.

The Manitoba bulk transmission system consists of two 900 km DC bipoles operating at ±500 kV bringing the northern hydraulic generation of about 3600 MW to southern load centers near Winnipeg. MH also has about 1300 MW of hydraulic generation and 230 MW thermal generation distributed within the southern region of the province. Bulk AC transmission in

Manitoba includes a network of transmission lines operating at 230 kV extending from Hudson Bay to Winnipeg, and Winnipeg to Brandon load centers in the west. MH system is connected to the Saskatchewan Power System in the west through three 230 kV interconnections. Manitoba's system is also connected to the east via two 115/230 kV phase shifted 230 kV interconnections to the Ontario Hydro System. High capacity connection to the south is through a 500 kV line, which extends from the Dorsey Station in the outskirts of Winnipeg to Forbes and Chisago near the Twin Cities. This connection was preceded with two 230 kV connections at LaVerendrye – Drayton and Richer – Moranville which continues on to Running and Shannon.

Participants in RRVSPG

Participants in the RRVSPG process include:

- Basin Electric Power Cooperative (BEPC)
- Great River Energy (GRE)
- Manitoba Hydro (MHEB)
- Minnesota Power (MP)
- Minnkota Power Cooperative (MPC)
- Missouri River Energy Services (MRES)
- Montana Dakota Utilities (MDU)
- Northwestern Public Service Company (NPS)
- Otter Tail Power Company (OTP)
- Western Area Power Administration (WAPA)
- Xcel Energy (XCEL)

Participation is encouraged from all interested parties.

3.4.2 RRVSPG Initiatives

The RRVSPG has undertaken the following initiatives aimed at improving the regional planning process:

Model Building Process

The RRVSPG realizes that the end-use objectives of the models developed by the Model Building Working Group (MBWG) may in fact be different for various MAPP users. For instance, subregional planning groups analyze native load serving issues while operating groups may study transfer limitations at flow gates. In the past, the users have customized MBWG models to meet their own individual needs. The RRVSPG would like to work with the MBWG so that the original model series can be developed with each end-use in mind.

Automatic Contingency Screening Analysis

In an effort to provide an outlook for the condition of the region, the RRVSPG plans to provide a near term assessment of the region through the completion of AC contingency checking analyses. The group is developing specific data files to support PSS/E's Activity ACCC to simplify this effort. In addition, various reporting tools, which parse ACCC results, are being developed to provide convenient reports.

Minnesota State Transmission Plan

Statues effective August 1, 2001 require that each public utility, municipal utility, and cooperative electric association, or the generation and transmission organization that serves each utility or association, that owns or operates electric transmission lines in Minnesota shall jointly or individually submit a transmission projects report, or transmission plan, to the commission by November 1 of each odd-numbered year.

The subregional planning groups of MAPP will provide input into the development of the state transmission plan. The RRVSPG continues to monitor developments towards this goal.

3.4.3 Benchmark Analyses

Preliminary automatic contingency analyses has been completed for 2001, 2004, 2009 planning horizons using models developed for the Red River Valley / West Central Minnesota Transmission Improvement Planning Study (RRV/WMN TIPS), which is described later in this report.

The following general observations and comments regarding system performance are noted and require further investigation:

- Facility loading increases over the planning horizons as expected with load growth.
- The loss of the Maple River 230/115 kV transformer appears to cause the highest degree of loading on remaining elements with redistribution of power flows for both summer and winter planning horizons.
- A significant number of buses have voltage levels below nominal for system intact cases. Single contingencies significantly increase the number of buses having voltages below nominal.
- A large number of contingency cases failed to solve and require manual analysis. The most prevalent contingencies that failed to solve involved 345 kV line outages.

Further review of system intact cases for 2001 provided the following insights regarding reactive compensation:

- Insufficient reactive compensation of transformer and line losses and load requirements result in excessive reactive power flow on the 230 kV system.
- A preliminary review of power flows for West Central Minnesota suggests that compensation to supply reactive power to load may be necessary for the following locations:

Benton Co.	Henning	Riverton
Cass Co.	Hubbard	Wahpeton
Crookston	Moderow	Willmar
Ellendale	Moorhead	
Falconer	Red River	

- A preliminary review of power flows for West Central Minnesota suggests that compensation of line losses may be needed for the following lines:

  345 kV Center – Jamestown – Buffalo – Maple River

  230 kV Heskett – Wishek – Ellendale

  230 kV Big Stone – Blair

  115 kV Lines Loaded Above 25 MW

- A preliminary review of power flows for West Central Minnesota suggests that shunt compensation may be needed to offset transformer losses at the following locations:

230/115 kV Benton Co.	230/115 kV Wing River
230/115 kV Maple River	230/115 kV Winger
230/115 kV Riverton	345/230 kV Maple River

The RRV/WMN TIPS study will develop conceptual improvement alternatives to reinforce the region and will examine the reactive requirements for the region.

3.4.4 Planned Improvements

The following provides a progress update for facility additions in the region:

Manitoba - United States Northward Transfer Enhancement (Harvey – Glenboro Project)

The 1998 RRV SPG plan identified five transmission alternative plans for further study prior to selection of a recommended plan. Each of these plans met the objectives of initially providing approximately 700 MW of MH-US northward transfer capability. Further studies were recommended to assess additional benefits including enhancement of MH-US southward transfer capability, local load serving benefits, impact on system losses, and the ability to provide increased North Dakota generation outlet capability. Manitoba Hydro and Northern States Power carried out these additional studies under the direction of the RRV SPG. Based on the results of the study, a report was prepared recommending that a new 230 kV transmission line be constructed from Harvey to Rugby in North Dakota to Glenboro in Manitoba. The location of the line is shown geographically in Figure 3.4-2 below.

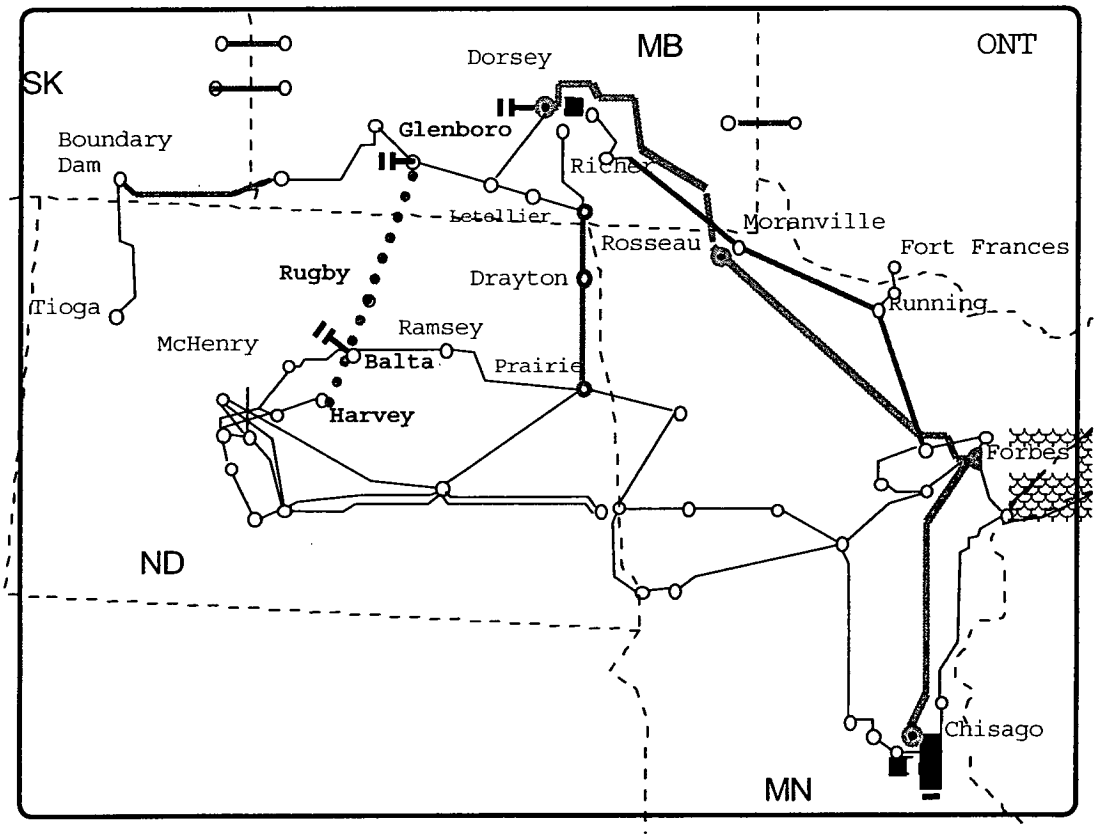


Figure 3.4-2. Geographic Location of the Harvey-Rugby-Glenboro 230 kV Line

The proposed Harvey-Glenboro line will be approximately 160 miles in length, with the Harvey to MH-US border portion being about 100 miles and the MH-US border to Glenboro portion being about 60 miles.

MHEB, NSP and OTP are the Harvey - Glenboro project sponsors. MHEB, NSP, OTP and GRE are parties to seasonal diversity contracts. This project will enhance the long term MH - US northward transfer capability to allow delivery of these contracts, as well as to provide load serving benefits in North Dakota and Manitoba.

The project sponsors have completed design review studies and submitted the report to the MAPP Design Review Subcommittee for technical approval of the project. DRS approval was obtained at DRS meetings on October 17, 2000, with further discussions on November 17, 2000 and December 11, 2000.

The current single line diagram for the Harvey-Rugby-Glenboro facilities is shown in Figure 3.4-3.

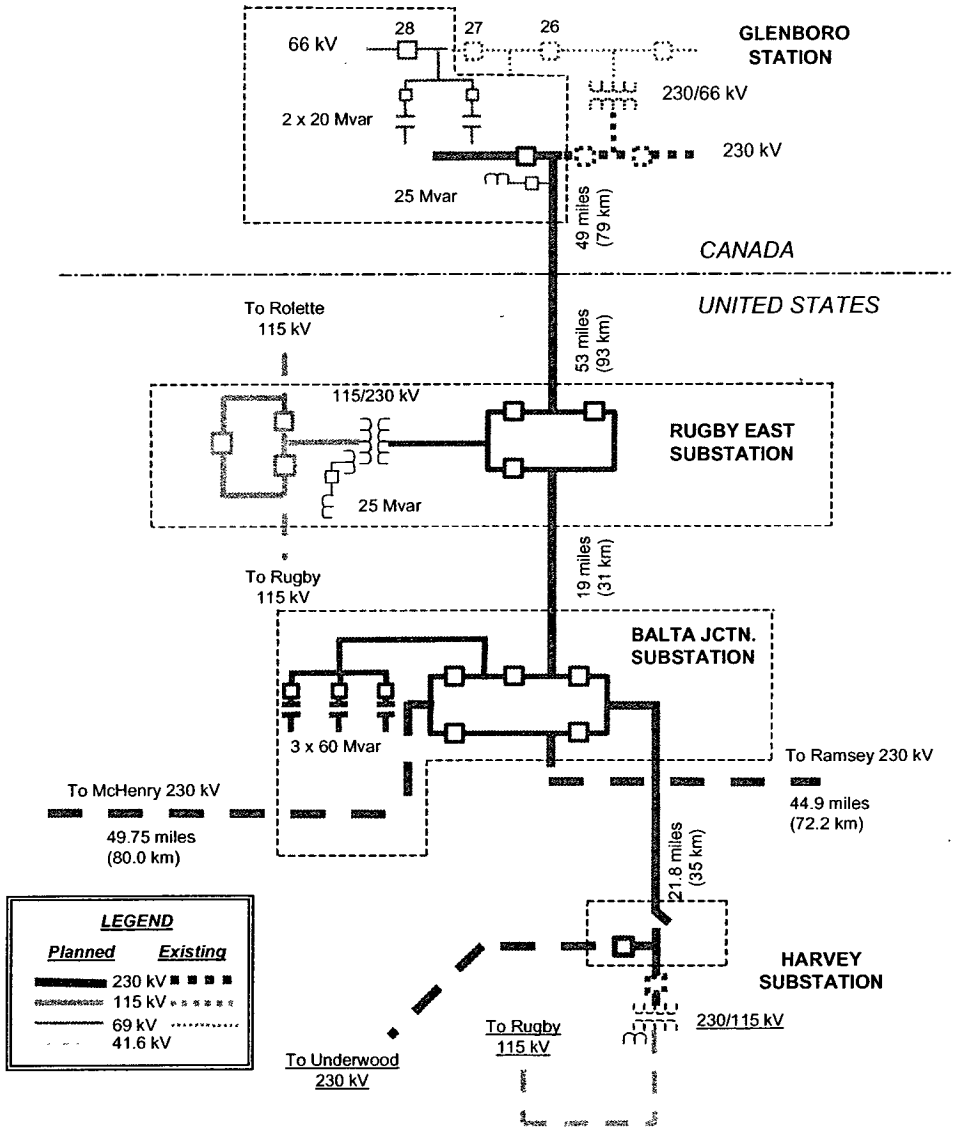


Figure 3.4-3. Harvey - Glenboro 230 kV line Single Line Diagram

In Canada, the National Energy Board (NEB) Application, which includes the Environmental Impact Study, is being finalized. Legal staff has drafted a Cabinet Submission and Order in Council in preparation for the NEB filing. The NEB Application is expected to be filed in mid-August 2001, pending receipt of the Order in Council. An application to Manitoba Conservation (Provincial) will be made at the same time. The Provincial and Federal reviews are also expected to take place concurrent with the NEB review. The Provincial, Federal and NEB review processes will take a minimum of three months to complete. Land acquisition will follow in the fall.

Negotiation of the Facilities Construction Agreement has been completed and the agreement has been signed by all three companies on July 13, 2001.

In the US, OTP has divided its project into two sections - Section I extends from Harvey to Rugby, and Section II extends from Rugby to the Manitoba border. OTP has received route permits for both sections of the project from the North Dakota Public Service Commission (PSC). A route permit for Section I (Harvey to Rugby) was issued in October 2000, which was followed by a permit for Section II (Rugby to the border) in late December 2000. Both approvals required from the ND State Legislature have been received in January 2001 from the Senate and in March 2001 from the House. Over 50% of the land acquisition has been completed in Section II.

Xcel Energy's application for a Presidential Permit has also been filed with the US Dept of Energy and the permit is expected to be issued by mid-September.

An Operations Coordinating Agreement has been drafted and it is under review. A joint application (MH and OTP) will be filed with the International Boundary Commission (IBC) once submission is made to Manitoba Conservation and the NEB. Receipt of this approval will allow the transmission line to physically cross the international border.

Brandon Combustion Turbine

Construction is continuing to install two simple cycle natural gas combustion turbines (CTs) at the Brandon Generating Station with an in service date of May 2002.

The new facility will improve the reliability of the resource supply to Manitoba load and firm export transactions by firming up the hydraulic generation during periods of low water (drought conditions in Manitoba) or generating equipment outages.

The two new Brandon CTs will have an average rating of 230 MW in the summer and 272 MW in the winter.

The units will be terminated into existing 115 kV breaker positions, which are available from the retired coal-fired Brandon Units 1 & 2. Consequently, minimal new transmission will be required to integrate the units into the Manitoba Hydro transmission network.

A study will be completed by January 2002 for MAPP Design Subcommittee approval as part of the accreditation process for the CTs.

Manitoba Area Transmission

Manitoba Hydro has plans to refurbish and re-conductor a number of 115 kV lines in the system. In northern Manitoba, the conversion of the Kelsey G.S. outlet lines designated as lines K24W and R26K from 138 kV operation to 230 kV along with an installation of a new Kelsey 250 MVA 138/230 kV transformer has been deferred to 2004. A fourth 230 kV line from Winnipeg to Brandon is planned to be build in year 2007, will be deferred by about ten years with the addition of the Brandon CTs and the proposed new Harvey-Glenboro interconnection.

Shannon Transformer 230/115 kV Addition

Minnesota Power's (MP) Shannon Substation 230-115 kV autotransformer becomes overloaded with the loss of MP's 96 Line, a 230 kV line extending from the Shannon Substation to the Minntac Substation. This condition worsens with the simultaneous outage of Manitoba Hydro's D602F Line, a 500 kV line extending from the Dorsey Substation to the Forbes Substation. Existing operating guides attempt to lower the flow along the Manitoba – United States transmission interface (MHEX) with the loss of D602F; however, the remaining power flow across the interface is still sufficient to aggravate overloading of the Shannon autotransformer when the 96 Line is also out of service. Minnesota Power confirmed the extent and nature of overloading on this transformer. Based on a 2009 planning horizon, overloads ranged from 120% to 151% depending on native load, prior outage conditions of D602F and MHEX levels. Similar results were achieved for the present system.

Minnesota Power plans to relocate an existing transformer or purchase a new transformer to complement the existing transformer already installed at the Shannon Substation for installation in 2002. This improvement is being implemented in the near term to avoid possible increases in MAPP's Operating Reserve Requirements (MORR) with reduction of MHEX limits for prior outage of D602F due to the existing constraints at Shannon.

Audubon-Detroit Lakes – Frazee 115 kV Line

Loads within north central Minnesota have driven a need for a larger load serving line within the area. Past studies have identified the need for a 115 kV line between the Audubon Substation and Frazee. This project is intended to be an extension of the Inman – Rush Lake – Perham – Frazee 115 kV project. The project will consist of three segments: the upgrade of the current Audubon-Detroit Lakes 41.6 kV line to 115 kV, increasing the tap at Detroit Lakes from 41.6 kV to 115 kV, and constructing a new 115 kV line from Detroit Lakes to Frazee. As part of this project, the 115 kV bus at the Audubon Substation will be rearranged. Project sponsors include Detroit Lakes Public Utilities, Otter Tail Power Company, Lake Region Electric Cooperative, Great River Energy, Western Minnesota Municipal Power Agency, and Missouri River Energy Services. It is expected to have this 115 kV line in service by the end of 2004.

Baxter-Brainerd 115 kV Line

A new 115 kV line is expected in the Baxter-Brainerd Area. Present and projected load served by Great River Energy has exceeded the capability of being reliably served from the existing 34.5 kV system. Great River Energy has proposed to build a 115 kV line between Minnesota Power's Baxter and Brainerd substations. Great River Energy 34.5 kV loads of Baxter and Southdale will then be converted to the new 115 kV line. This project is expected to be completed in 2004.

Hubbard-Park Rapids 115 kV Line

The 34.5 kV system in the Park Rapids area is becoming voltage limited and reliability is becoming an issue. One of the existing 34.5 kV sources from Hubbard is capable of 115 kV conversion. Great River Energy is proposing a new 115/34.5 kV source in the Park Rapids area with the line to Hubbard being converted to 115 kV in 2004, although load growth will ultimately determine timing. Other 34.5 kV improvements will be included with this project.

GRE DC Upgrade

Great River Energy is seeking additional outlet for its Coal Creek plant, which currently delivers its power to the Twin Cities line via a 400 kV DC line. With a minor DC line voltage upgrade, the existing line will be able to carry about another 2.5% of power allowing for the margin needed by Coal Creek for outlet.

Bemidji Area Capacitor Banks

The Bemidji area is a region that is experiencing very rapid growth rates. Loads have grown within this region enough to depress voltages below emergency criteria during critical contingencies. The most severe outage is the Winger to Wilton 230 kV line. A study has been conducted by Otter Tail Power Company to find a short-term solution to low voltage problems in this area. Study results have shown that capacitor bank additions to the area have somewhat significant impacts on voltages. It has been identified that the most effective placement of capacitors in the region are the 115 kV buses of Wilton and Bemidji. Agreements are in place between Otter Tail Power Company and Minnkota Power Cooperative for Otter Tail to place a 20 MVAR bank at Bemidji and for Minnkota to install a second 23.5 MVAR bank at Wilton. Otter Tail plans to have the 20 MVAR installed at Bemidji by the Winter of 2001, while Minnkota expects to have their second 20.5 MVAR bank installed at Wilton in the Spring of 2002. The addition of these capacitor banks will provide an interim fix for the transmission system. A transmission planning study (RRV / WMN TIPS) is presently being conducted to identify long-term transmission improvements to this region. These capacitor installations at Bemidji and Wilton will complement any future transmission additions to the area.

Benson Area Capacitor Banks

Great River Energy will be placing a 36 MVAR capacitor at the Benson 115 kV substation to help resolve voltage issues on loss of the Morris source.

Paynesville Area Capacitor Banks

The Paynesville 115 kV capacitors were placed in service July 2000. These 20 MVAR banks (there are two) are expandable to either 30 or 40 MVAR in the future. Presently, the bank size is limited by system fault strength being inadequate for increments over 20 MVAR.

West Central Minnesota Capacitor Bank

Low voltages on the 115 kV and 230 kV systems occur within the Red River Valley region based on historical operating experience. These situations are attributed to deficiencies in reactive supply within the region. Preliminary analyses related to the RRV/WMN study also support this notion. Minnesota Power plans to install at least one shunt capacitor bank at 115 kV in its Western Division to offset transformation and line losses. Analyses show that the region will also benefit since additional reactive support will be provided to the 230 kV system.

A 27 MVAR bank has been budgeted and a tentative location of Badoura has been selected. The location and size may change with completion of detailed reactive planning analyses. A shunt capacitor bank may also be located near the vicinity of the Riverton Substation to offset transformation and line losses.

3.4.5 Generation Interconnection Requests

The following describes significant generation interconnection requests that may affect the region:

Big Stone

Otter Tail Energy Delivery has received a transmission request for either a 500 MW or 600 MW generation addition at the Big Stone Plant site. The new generation is scheduled to be placed in service in 2007. Otter Tail is currently in the process of conducting studies to identify the necessary transmission additions required to accommodate this request.

Coal Creek

Over the last few years GRE has been upgrading various components of the Coal Creek Station (CCS) generating facilities in order to improve efficiency and extend the life of the units. These upgrades have resulted in increased unit capabilities. GRE is studying the transmission system performance at increased CCS output (1153 MW) and higher CUDC line flows (1128 MW). This report will be presented to the MAPP DRS and SPGs during the fall of 2001.

FibroMinn

This new generating facility will be located in Benson, Minnesota, and connected to the GRE Benson 115 kV bus. The 50 MW of output from the unit will be delivered to the Xcel Energy network load. GRE is currently studying the effects of this generation addition and will be reporting the results to the MAPP DRS and the SPGs.

Glendive/Miles City

Montana-Dakota is planning to add a 40 MW natural gas-fired combustion turbine to its existing Glendive Combustion Turbine site in Glendive, Montana. The company has begun the environmental air permitting process and likely will order the turbine in 2002. With that time frame, the new combustion turbine can be operational in the summer of 2004.

Montana-Dakota is studying the addition of two 40 MW natural gas-fired combustion turbines, one to its existing Glendive Combustion Turbine site in Glendive, Montana, and one to its existing Miles City Combustion Turbine site in Miles City, Montana. The new combustion turbines would be operational in the summer of 2007. The addition of these two turbines is dependent upon the outcome of the "Lignite 21" and "Big Stone" feasibility studies.

Lignite 21 – MDU

Montana-Dakota is investigating the feasibility of a 500 MW lignite-fired baseload unit near Gascoyne, North Dakota, which could be considered commercial in 2008. The feasibility study is being funded through matching funds available from the North Dakota Industrial Commission (NDIC). The NDIC approved up to $10 million matching funds for this project in May 2001. The feasibility study involves a detailed environmental, economic, and transmission study which could lead to the construction of the 500 MW power plant, which has been referred to as the Lignite Vision 21 Project.

Lignite 21 – GRE

Similar to MDU, GRE is investigating the feasibility of a lignite-fired unit in North Dakota as part of the North Dakota Industrial Commission's Lignite Vision 21 program. GRE is considering a plant size up to 750MW at or near one of three sites: Coal Creek, Stanton, or New Salem with a 2008 in-service date. The feasibility study, including an evaluation of transmission alternatives, is proceeding in two steps: a preliminary evaluation during 2001 followed by a more-detailed evaluation in 2002.

Griggs-Steele Wind Development Zone

Western has received a transmission request from the Griggs-Steele Wind Development Zone for 130 MW of transmission services. The 130 MW of wind generation will be located near the Pickart, ND substation. Approximate in-service date is Dec. 2003. System studies are commencing.

3.4.6 Planning Studies

RRV/WMN TIPS

In conjunction with the West Central Minnesota Study (page 10 of the "2000 MAPP Red River Valley Transmission Plan 2000-2009"), the scope of this study has recently been extended to include regions within the Red River Valley to lend itself to be called the Red River Valley / Western Minnesota Transmission Improvement Planning Study (RRV / WMN TIPS). Load serving issues to the Red River Valley with the loss of the McHenry – Ramsey 230 kV line during the Winter of 2000 – 2001 has been the trigger point for combining these two studies into one regional study.

This study has been a purely "work-in-process" project up to this point. A tremendous amount of time has been spent gathering load data and verifying topologies within the models. Six planning horizons are to be investigated during this study. These will include Summer and Winter Peak models for 2001, 2004 and 2009.

Otter Tail Power Company and Minnesota Power are taking the lead in this study with the intent of finding the most efficient and economical way to address local load serving issues within the study area.

Preliminary analysis will include the investigation of numerous fixes to the study area. Comments from members of the RRV SPG have given way to this rather lengthy list of possible fixes within the study area:

Options Considered for RRV / WMN TIPS

Western Sources	
230 kV Line	Harvey – Prairie
230 kV Line	Garrison – Ramsey – Drayton
345 kV Line	Coal Creek – Underwood – Harvey – Prairie
Voltage Upgrade 115 kV to 230 kV	Garrison – Max – Minot – Rugby
Voltage Upgrade 230 kV to 345 kV	Bismarck – Jamestown – Fargo
50% Series Compensation	230 kV Garrison – Jamestown Line, Jamestown – Fargo Circuits 1 & 2
75% Series Compensation	230 kV Garrison – Jamestown, Jamestown – Fargo Circuits 1 & 2
SVC	WAPA Jamestown
Eastern Sources	
230 kV Line	Boswell – Wilton
115 kV Line	Roseau – Karstad
Voltage Upgrade 115 kV to 230 kV	Wilton – Bemidji – Nary – Laporte – Badoura
Northern Sources	
230 kV Line	LaVerendrye – Letellier – Drayton – Prairie – Maple River
230 kV Line	LaVerendrye – Stanley – Hensel – Drayton – Donaldson – Halma – Karlstad-Viking – Thief River – Plummer – Plummer Tap – Winger
230 kV Line	Letellier – Drayton, Circuit 2
345 kV Line	Dorsey – Karlstad – Viking – Thief River – Plummer – Plummer Tap – Winger
Southern Sources	
345 kV Line	Benton County – Alexandria – Maple River
345 kV Line	Benton County – Maple River
345 kV Line	Watertown – Granite Falls
345 kV Line	Granite Falls – Blue Lake
345 kV Line	Watertown – Granite Falls – Blue Lake
Voltage Upgrade 230 kV to 345 kV	Fargo – Moorhead – Morris – Granite Falls
Internal Improvements	
Voltage Upgrade 115 kV to 230 kV	Winger – Mahnomen – Ulrich – Audubon
Voltage Upgrade 115 kV to 230 kV	Fargo – Caledonia – Grand Forks
SVC	Prairie

Initial analysis will include all options listed in the above table. Contingency screening analyses will be completed to determine the most effective improvements. The improvements considered most effective will be analyzed in further detail to determine which option(s) will provide the best overall enhancement to serve load within the study area. Plans are to complete this study by this fall.

TPSC Forms

Updated TPSC Forms 1 –5 identifying planned improvements for the region are provided in Appendix A.

3.5 Upper Mississippi Valley

3.5.1 Introduction

Purpose of Report

The purpose of this report is to provide an update to the August 2000 Upper Mississippi Valley Subregional Planning Group (UMV SPG) 10-year transmission plan. The report is based on the results of study work performed since the 10-year plan was compiled. It also includes input from the staff of the various utilities that own and/or operate the transmission network in the subregion.

Description of Upper Mississippi Valley (UMV) Subregion

The UMV subregion of MAPP consists of approximately the southern half of the state of Minnesota and the western half of the state of Wisconsin. The electric transmission system consists of 115, 138, 161, 230, 345, and 500 kV AC transmission lines and a 400 kV DC transmission line interconnected at substations by large power transformers. Discussions of the 34.5 and 69 kV subtransmission systems are included where the subtransmission provides the major of power supply into a given area.

The following entities own and/or operate transmission lines in the UMV subregion:

Alliant Energy (ALT)
Dairyland Power Cooperative (DPC)
Great River Energy (GRE)
Hutchinson Utilities Commission (HUC)
Minnesota Power (MP)
Xcel Energy/Northern States Power (NSP)
Rochester Public Utilities (RPU)
Southern Minnesota Municipal Power Agency (SMMPA)
Willmar Municipal Utilities
Wisconsin Power and Light Co. (WPL)

Methodology

The transmission owners periodically review the status of the transmission network and project the amount of new load that will be added to the network, including new generation additions and transmission service requests. The network is then analyzed under a variety of contingency outage scenarios using computer simulation programs and other means. The analysis results are then compared to the MAPP planning criteria and other local planning criteria developed following national practices, to determine if system improvements are needed. Depending on the initial purpose of the analysis, the results may be summarized in a formal report or spawn a more

comprehensive, thorough analysis through an expanded study team consisting of several other owners and interested parties.

The resulting study reports provide a knowledge base used by the utilities to determine network expansion projects. In cases where the need is immediate or near-term, a new project may be implemented. In cases where the need for a project is several years out, the report provides a guideline for expansion should load growth increase or a new, unexpected large load be added to the network. In either case, the analysis process provides a level of confidence that the network expansion projects are being added in an efficient, coordinated, and economical manner.

3.5.2 Overview of Changes to the UMV 10-Year Plan

Planning is an ongoing and constantly changing process. New information, changing plans of developers, generation providers and even the economy all result in the need to continue to re-evaluate the best way to accommodate the needs of the transmission system users.

Projects start out as general ideas of the planning engineers to address likely needs expected to arise in the future. As the time gets closer to a final commitment to a project, the clearer these needs become and the more scrutiny the ideas and plans undergo to assure the projects which do go forward are well thought out and comprehensively evaluated. This process is apparent in the changes that have occurred in the UMV 10-year plan.

The largest changes are a result of the firming up of a number of generation plans in the UMV region. Some of the largest include new combustion turbine generation at Hurley and Ashland in northern Wisconsin and Faribault in Minnesota. These will require varying amounts of transmission development for outlet capability. The most significant of all is in SW Minnesota where wind generation developers are requesting to interconnect major wind developments.

Along with generation additions, further analysis has been conducted in the greater St. Paul area to firm up transmission plans requiring immediate commitment.

3.5.3 Discussion of Changes to the 10-Year Plan

Generation Outlet

A number of generation additions have been announced since the last update. These proposals are in various stages of development and are subject to change. The following describes the transmission additions associated with these proposed additions. As the generation proposals firm up and construction begins, the transmission construction schedules (and plans where the generation scope changes) to support them will also be firmed up.

Wind Generation

Since last year's report, Xcel Energy has accepted bids for its remaining wind generation commitment for a total of 425 MW. This is all installed or scheduled for constructed along the portion of the Buffalo Ridge in SW Minnesota. There is not sufficient transmission capacity in the region to support this level of wind development. The transmission required to support the 425 MW commitment was determined and is now in final stages of approval for construction. This consists of the Chanarambie-Lk Yankton and Lk Yankton-Lyon Co (Marshall Tap) 115 kV lines and associated substation facilities including a new Lyon Co substation near Marshall Minnesota. This study work is documented in "Preliminary Results of an Interconnection Study for 36-130 MW of Wind Generation near Chanarambie, Minnesota" January 11, 2001.

There are in addition other commitments for wind generation along the Ridge. Several wind generation developers are proposing additional large blocks of generation. A second study for wind generation outlet is in the final stages of completion. This study is identifying the transmission outlet requirements for an additional 400 MW of wind generation along the Buffalo Ridge in Minnesota, bringing the total to 825 MW.

There are four basic options identified; the preferred plan adds a 345 kV Split Rock-Lakefield Jct. line with a 115 kV line from Chanarambie to a new Fenton collector station to a new Nobles Co 345-115 kV station. This option appears to offer the best overall results with respect to:

- Power system performance (system intact and contingent loadings and voltages)
- Power and energy losses (MW and MWH)
- Practicality (logistics of construction and operation)
- Price (cumulative present worth cost)

Along with the 345 kV line the following additional transmission capacity additions are required:

- Upgrade Wilmarth-Lakefield 345 kV
- Build 2nd Lakefield Jct.- Fox Lk 161 line
- Rebuild Fox Lake – Rutland-Winnebago Jct.161 kV
- Upgrade Minn Valley 230-115 TX to 187 MVA
- Reconductor W. Faribault-Loon Tap-Dome-Summit 115 kV line to 310 MVA
- Reconductor Grant Co. - Elbow Lake-Brandon-Alex Switching station-Alexandria-Douglas Co 115 kV line to 310 MVA
- Reconductor Willmar - Kerkhoven Tap 115 kV line to 200 MVA
- Reconductor Paynesville - Wakefield 115 kV to 310 MVA

- Reconductor Minn. Valley - Redwood Falls tap - Franklin 115 kV to 310 MVA
- Upgrade the Black Dog 230 - 115 kV transformer to 336 MVA

There are also two significant 69 kV upgrades associated with the wind outlet:

- Rebuild Franklin - Bird Island 69 kV to higher capacity (probably to 115 kV standards and with double circuit capability)
- Rebuild Paynesville - Munsun Tap 69KV to higher capacity (probably to 115 kV standards and with double circuit capability)

This option also appears to be highly compatible with other transmission improvements which may be undertaken to address local and regional load-serving needs, enhance power system transfer capability, or provide outlet capacity for additional generation developments in the Dakotas, Minnesota, and Iowa.

The details of this analysis are documented in a report entitled Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission Outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0 - 400 MW beyond initial 425 MW)

FibroMinn Biomass Unit

An Independent Power Producer (IPP) has proposed the construction of a biomass generating unit (FibroMinn) near Benson, Minnesota. The unit will have an output of approximately 50 MW and will be connected to the GRE 115kV transmission system at the existing Benson substation. The unit will be fueled by turkey litter and the energy produced will be sold to Xcel Energy.

The transmission system in the area is already above capacity and the additional power flow caused by the unit causes the transmission lines causes even more overloading. Present plans call for the facilities to be upgraded in early 2004. Until the facilities are upgraded, the Fibrominn plant output may be restricted depending on transmission operating conditions.

W. Faribault Combustion Turbines

An interconnection request has been received for a 150 MW Combustion turbine site near Faribault MN. This is associated with a generation capacity bid accepted by Xcel Energy. To accommodate this, the existing 115-69 kV transformers at W. Faribault need to be replaced with 2-112 MVA capacity units. Also, the Loon Lake 115-69 kV transformer will be replaced with a 70 MVA transformer. There is also additional 69 kV transmission upgrade out of W. Faribault required with this. (This will likely be built for 115 kV capacity but operated at 69 kV). There is the possibility of some delay in this projects due to siting issues.

The details of this analysis is documented in a report entitled *Preliminary Results of an interconnected Study for 250 MW of CT Generation Near Faribault, Minnesota. January 11, 2001.*

Hurley and Gingles Combustion Turbines

Two interconnection requests where received for 55 MW combustion turbine sites near Hurley and Ashland in northern Wisconsin. Aside from the direct 115 kV tie line into the Hurley and Gingles substations, only substation work is required for these additions. There is the possibility of some delay in these projects due to siting issues.

The details of this analysis is documented in a report entitled *Preliminary Results of an Interconnected Study for 55 MW of CT Generation Near Ashland, Wisconsin and 55 MW of CT Generation near Hurley, Wisconsin. January 11, 2001.*

Black Dog Repowering

The Xcel Energy Black Dog generating plant is replacing and upgrading units 1 and 2 with new combustion turbine technology. The new generation will now be gas-fired. This will add 115 MVA of additional capacity at the plant site. There will be changes to the substation configuration at Black Dog and reconductoring to higher capacity of two existing 115 kV circuits from Black Dog to Wilson substations. Due to work load scheduling, the reconductoring will be completed by fall of 2001.

Chaska (Minn River Generating Station)

Actual operation has identified an additional 4.9 MW of capacity available from this plant. Final MAPP approvals are pending for this added capacity.

EPS/BECK Power

A 50 MW biomass generating plant is preliminarily proposed near St. Peter, Minnesota for 2004. A preliminary study identified the need to increase capacity of the Traverse to Arlington 69 kV line. This condition occurs when the Lakefield Generation is on and the Blue Lake – Wilmarth 345 kV line is outaged. This 22 mile project would likely be built for 115 kV but initially operated at 69 kV. The actual in-service date of this project is dependent on the firming up of the generation project.

Transmission Load Serving Study Updates

Long range transmission plans are in a continuing state of review. This review allows for refinements in scheduling and adjustments if major changes occur in load development. Also, as the time horizon approaches for construction, the details on which the plans decision are made become more clear. One major milestone was achieved when regulatory approval was granted for the Arrowhead-Weston 345 kV line in the summer of 2001, two years after it was submitted to Minnesota and Wisconsin regulatory agencies. The current estimated in-service date for the

line is 2005, whereas it was 2003 when the project was initially proposed in 1999. The original project scope for an estimated 229-mile route (with a 345-115 kV substation at Tripoli) has changed to the recently approved 220-mile estimated route without a 345-115 kV substation in the plan. The map (Form 4 in Appendix A) reflects the most recent scope and approximate route. The following describes other major changes in the plan from last year's submittal.

Greater St. Paul Area

There are three 115 kV lines serving the city of St. Paul in its inner ring of suburbs. There are now numerous conditions where these facilities could exceed their safe operating limits. Originally, a second Terminal-Western 115 kV line (via a new Fairview substation) was proposed. However, alternatives for Fairview have been developed and a similar priced alternative has been proposed. This is a new Red Rock – Daytons Bluff 115 kV line via Battle Creek. This project has the advantage of increasing the reliability of the Daytons Bluff station by adding a third line into the substation. This will allow utilization of the full reliability capability of the three distribution network design of the Daytons Bluff station.

Likewise the distribution plans are now such that the reconductor of the Terminal-Rose Place 115 kV line will likely be deferred to later than the study period reported here.

Chisago – Apple River Project

Additional detailed engineering analysis have resulted in some minor changes to the details of this project. The recommendation is to construct the Minnesota portion of this project at High Capacity 115 kV. While in Wisconsin, the project would continue with 161 kV. Details of this analysis are documented in Chisago 115-161 kV Hybrid Analysis.

Downtown Minneapolis

The project to add cooling to the Fifth Street-Main Street 115 kV cable was found during engineering not to add sufficient capacity. A new study is required of the local downtown Minneapolis transmission supply including any impacts from the distribution facility moves associated with the new light rail line in Minneapolis.

Garfield and Nicollet Substations and Associated Transmission

Distribution planning had a plan to upgrade two old 13.8 kV to 4 kV stations to 115 kV service via use of existing distribution duct lines with low capacity 115 kV cables. However, this plan has now been deferred by other alternatives to beyond the present study period.

Burnsville Transformer Addition

An change to the forms worth noting is the addition of a second, 115/69kV transformer at the Burnsville bulk substation. This project replaces the conversion to 115kV of the GRE-Minnesota Valley load at the Prior Lake substation. After a physical review of the existing Prior Lake substation site it was determined that there was insufficient space to convert the substation to the

higher voltage. The Burnsville transformer addition will add sufficient transformation capability to alleviate the overloading of the Glendale 115/69kV transformers during contingencies.

Some of the 69kV transmission lines in the Burnsville area will also have to be reconductored as part of the introduction of additional capacity in the Burnsville area.

New Sandstone Substation

GRE will be adding a new 230/69 kV, 60 MVA transformer at Sandstone to provide voltage support to the GRE 69 kV and MP 46 kV system. Growth in the Hinckley-Sandstone area is causing low voltage situations during system intact and contingent events.

Dickinson 115/69 kV Addition

A new 115/69 kV, 48 MVA source will be added at the existing GRE Dickinson substation to provide a new 69 kV delivery point into a long radial 69 kV line. This source will provide improved reliability to this area that consists of the expanding northwest Twin Cities suburban development.

Section 4. Projects Completed

This section identifies the transmission and generation projects that have been completed and placed in-service beyond the facilities listed in the 2000 MAPP Regional Plan. Completed projects include only the facilities that have become known to the TPSC through the process of acquiring the information from the SPGs.

The official planning process started with the effective date of the MAPP Restated Agreement in November 1996, but was not implemented through its first planning cycle until November 1998. As such, some participants or other related industry players may not realize or be familiar with the TPSC reporting process of reporting expansion plans through the SPGs. Therefore, some facilities have been planned and placed in service without the knowledge of the TPSC. The following tables do include some completed facilities that were not known as planned facilities in the 2000 MAPP Regional Plan. In Table 4.1, Table 4.2, and Table 4.3, new information about completed branches (lines and transformers), devices, and generators appears in red (gray for black-and-white print). Where an entire row of items appears in red/gray, the facility was not in the 2000 Regional Plan but has since been reported as a completed project. The TPSC did extensive work to confirm the completion status, but did not do extensive survey activity to revise exact in-service dates. However, some revised in-service dates were captured in the process, and are indicated as a red/gray revision.

Table 4.1. Transmission Lines and Transformers Completed Since 2000 Regional Plan

Transmission Lines and Transformers

						Line Mile Estimates						Need Estimates (SRM =100 %)						
In Service Date (mm/yy)	MAPP Sub-region or Other Region	From:	To:	Circuit #	Voltage(s) (kV)	Number of Alternatives or None Reported (NR)	Reconductor or Thermal Increase	Rebuild or Conversion	New	Total Miles	Summer Rating (MVA)	Network	Gen Outlet	Transfer Capability	Improvement (Losses, Maint, Availability, etc)	Other	A=Authorized P=Planned C=Completed W=Withdrawn
6/1/2000	ITWG	Ashawa	89 th	1	161	NR			11.0	11.0	363	100					C
6/1/2000	ITWG	88 th	100 th & 5 th Ave	1	161	NR			4.0	4.0	363	100					C
12/1/2001	ITWG	MEC Hespers	MEC Sheldon	1	69	NR			11.6	11.6	64				100		C
6/1/2001	ITWG	Hills	Sub 92	1	345	NR	16			16.0	1195			100			C
6/1/2001	ITWG	Sub 92	Walcott	1	345	NR	21			21.0	1195			100			C
6/1/2001	ITWG	Walcott	Sub 56 (Davenport)	1	345	NR	6			6.0	956			100			C
6/1/2001	ITWG	Sub 56	Sub 91	1	345	NR	13			13.0	956			100			C
6/1/2001	ITWG	Sub 91	Quad Cities	1	345	NR	14			14.0	1195			100			C
6/1/2001	ITWG	Quad Cities	Cordova	1	345	NR	2			2.0	1195			100			C
6/1/2000	NEBRASKA	Elsie	Red Willow Creek	1	115	NR			12.0	12.0	174	100					C
6/1/2000	NEBRASKA	Red Willow Creek	Blackwood Creek	1	115	NR			7.0	7.0	174	100					C
6/1/2000	NEBRASKA	Warrensburg	Odessa	1	161	NR			26.0	26.0	233	100					C
7/1/2000	NEBRASKA	Grand Island	Aurora	1	115	NR	13.8			13.8	137			100			C
7/1/2000	NEBRASKA	Aurora	York	1	115	NR	21.0			21.0	137			100			C
1/1/2001	NEBRASKA	Sub 1237	Sub 1236	1	161	NR			11.4	11.4	400	100					C
4/1/2001	NEBRASKA	Gentleman 345 kV	Gentleman 230 kV	2	345-230	1					336		100				C
6/1/2001	NEBRASKA	Wagener	Waverly	1	115	NR			5.0	5.0	363	90			10		C
6/1/2001	NEBRASKA	Pleasant Hill 345 KV	Pleasant Hill 161 KV	1	345-161	NR					400	100					C
6/1/2001	NEBRASKA	Pleasant Hill	Prairie Lee	1	161	NR		13		13.1	466	100					C
6/1/2001	NEBRASKA	Pleasant Hill	Longview	1	161	2		9.7		9.7	544	100					C
4/1/2000	RSV	Dorsey	Nespawa		230	NR			108.0	108.0	399	100					C
4/1/2000	RSV	Cornwallis	Nespawa		230	NR			36.0	36.0	399	100					C
10/6/2000	RSV	Cliff Lake Tx			230-115	NR					200	100					C
12/31/2000	RSV	Frazee	Rush Lake		115	NR			25.0	25.0	161	100					C
5/1/2000	UMV	Wheaton	Wheaton Tap		161	NR	2.2			2.2	445	100					C
5/1/2000	UMV	Benton Co	Benton Co Tap		115	NR	4.1			4.1	300	80		20			C
5/1/2000	UMV	Benton Co Tap	Granite City		115	NR			1.0	1.0	300	80		20			C
9/1/2000	UMV	Wissota (Hydro Lane)	T Corners		115	2		52.7		52.7	310	40			60		C
9/1/2000	UMV	Wissota Xfmr			115-69	NR					42	100					C
11/1/2000	UMV	Air Lake	Dodd Park		115	NR			4.0	4.0	300	100					C
11/1/2000	UMV	Air Lake	Lake Marion		115	NR			6.5	6.5	337	100					C
12/1/2000	UMV	Loon Tap	Loon Lake		161	1			16.0	16.0	191	100					C
1/1/2001	UMV	Pleasant Valley Xfmr		1	345-161	NR					500		100				C
3/15/2001	UMV	Black Dog	Wilson	1	115	NR	4.5			4.5	240		100				C
5/1/2001	UMV	Maynard Xfmr		1	115-69	NR					47	100					C
5/1/2001	UMV	Holcombe Xfmr			115-69	NR					47	100					C
6/1/2001	UMV	Gleason Lake	Gleason Lake Tap		115	NR	0.0				0	100					C
9/1/2001	UMV	Stone Lake	Bay Front		161	NR		56.0		56.0	445	100					C
9/1/2001	UMV	Stone Lake Xfmr			161-69	NR					50	100					C
10/1/2001	UMV	Black Dog	Wilson	3	115	NR	4.5			4.5	240		100				C

Section 4. Projects Completed

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Table 4.3. Generating Units Completed Since 2000 Regional Plan

	Generating Units				Planning Parameters						
In Service Date mm/yy	MAPP Sub-region or Other Region	Name:	Location:	Grid Injection Voltage (kV)	Summer Winter Rating (MW) Note 1	Nominal Dispatch Capacity Factor Note 2	Oil	Gas	Coal	Other	A=Authorized P=Planned C=Completed W=Withdrawn
[illegible]	IPWS	South Load Center Diesels	Waverly, Iowa	13.8	12	0.20%	X				C
[illegible]	IPWS	Stuart	Stuart, IA	13	2	0-10%	X				C
[illegible]	IPWS	Pella	Pella, IA		4		X				C
6/1/2000	IPWS	Anita Unit 4	Anita, IA	2.4	0.295	0-10%	X				C
6/1/2000	IPWS	Anita Unit 5	Anita, IA	2.4	0.295	0-10%	X				C
[illegible]	IPWS	Maquoketa 9	Maquoketa, IA	12	1.805	0-10%	X				C
6/1/2000	IPWS	Sibley 4	Sibley, IA	2.4	2	0-10%	X				C
[illegible]	IPWS	Story City 3	Story City, IA	12	3	0-10%	X	X			C
6/1/2000	IPWS	La Porte 3A	La Porte, IA	2.4	1.805	0-10%	X				C
6/1/2000	IPWS	La Porte 4A	La Porte, IA	2.4	1.805	0-10%	X				C
6/1/2000	IPWS	New London 1	New London, IA	12	2	0-10%	X				C
6/1/2000	IPWS	New London 2	New London, IA	12	2	0-10%	X				C
6/1/2000	IPWS	New London 3	New London, IA	12	2	0-10%	X				C
6/1/2000	IPWS	MEC Des Moines Generation	Des Moines	69	12		X				C
6/1/2000	IPWS	MEC Indianola Generation	Indianola	69	25		X	X			C
6/1/2000	IPWS	MEC Shenandoah Units	Shenandoah	69	20		X				C
6/1/2000	IPWS	MEC Knoxville Units	Knoxville	69	16		X				C
6/1/2000	IPWS	MEC Lundquist Units	Lundquist	69	20		X				C
6/1/2000	IPWS	MEC Landfill Generation	Quad Cities	69	3					X	C
6/1/2000	IPWS	AMES	Ames	69	34.1				X		C
6/1/2000	IPWS	MPW Unit 8	Muscatine, IA	69	36/24.2	80%			X		C
6/1/2000	IPWS	MPW Unit 8A	Muscatine, IA	69	16.3/18.4	90%			X		C
6/1/2000	IPWS	Dayton	Dayton, IA	12	2	0-10%	X				C
[illegible]	IPWS	Cedar Falls CT #2	Cedar Falls GT sub, IA	69	24/28		X	X			C
6/1/2000	IPWS	Pantora	Pantora, IA	12	2	0-10%	X				C
[illegible]	IPWS	CREC	Cedar Rapids, IA	161	585-600	100%				X	C
[illegible]	IPWS	Estherville	Estherville, IA	12	2	0-10%	X				C
6/1/2000	IPWS	Lenox	Lenox, IA	12	2	0-10%	X				C
6/1/2000	IPWS	Brooklyn	Brooklyn, IA	12	2	0-10%	X				C
6/1/2000	IPWS	Greenfield	Greenfield, IA	12	2	0-10%	X				C
[illegible]	IPWS	Winterset	Winterset, IA	12	2	0-10%	X				C
[illegible]	MAIN	Cordova Generators	Cordova, IL	345	178 / 230	50 -100%		X			C
[illegible]	MAIN	Cordova Generators	Cordova, IL	345	178 / 230	50 -100%		X			C
[illegible]	MAIN	Cordova Generators	Cordova, IL	345	181.5 / 230	50 -100%				X	C
6/1/2000	NEBRASKA	Sarpy County Units #4 & #5	Omaha, NE	161 KV	95			X			C
6/1/2001	NEBRASKA	Hawthorn Unit #7	Kansas City, MO	161 KV	80			X			C
[illegible]	NEBRASKA	Hawthorn Unit #8	Kansas City, MO	161 KV	80			X			C
6/1/2001	NEBRASKA	Hawthorn Unit #9	Kansas City, MO	161 KV	140			X		X	C
6/1/2001	NEBRASKA	Rokeby CT Unit #9	Lincoln, NE	115 KV	90 / 96			X			C
6/1/2001	NEBRASKA	Ames Plant	Pleasant Hill, MO	161 KV	595			X			C
[illegible]	LMV	Peaking / Diesel	Lakefield, MN	2.4/69	3					X	C
6/1/2000	LMV	Lake Marion	Lakeville	12.47/69	8 8	0-20 %	X				C
6/1/2000	LMV	Hastings	Hastings	12.47/69	8 8	0-20 %	X				C
[illegible]	LMV	Gas Turbine	Mower City MN, P Valy Twp	161	310/352	0-15 %		X			C
[illegible]	LMV	Utches Plus	Winnton		2 mw						C
[illegible]	LMV	Chaska / Mill Road	Chaska, MN	115	45			X			C
[illegible]	LMV	Lakefield Junction	Martin County, MN	345	550	0-20%		X			C
[illegible]	LMV	Diesel	Forest City, IA	69	6	0-8%	X				C
6/1/2001	LMV	Diesel	Lake Mills, IA	69	6	0-8%	X				C
[illegible]	LMV	Diesel	Hammond, WI	69	2 X 3	0-8%	X				C
[illegible]	LMV	Elk Mound	Eau Claire City, WI	161	84/96	0-20 %	X	X			C
[illegible]	LMV	Wilmar	Wilmar	69	12	0-20 %	X				C
		Note 1: Wind Ratings at Nacelle/s (Accredited)									
		Note 2: For Analysis Purposes CF = 8% for Peaking, 30% for Intermediate and 70% for Base									

Table 4.2. Devices Completed Since 2000 Regional Plan

Devices (capacitors, reactors, FACTS, etc):

				Need Estimate (SUM =100 %)							
In Service Date (m/d/y)	MAPP Sub-region or Other Region	Name and Type:	Location:	Voltage(s) (kV)	Summer Rating (Various Units)	Network	Gen Outlet	ATC	Improvement (Losses, Maint, Availability, etc)	Other	A=Authorized P=Planned C=Completed W=Withdrawn
1/31/2001	ITWG	Capacitor	MEC Bondurant	161	50 MVAR				100		C
1/31/2001	ITWG	Capacitor	MEC SE Polk	161	50 MVAR				100		C
5/1/2001	ITWG	Capacitor	MEC Booneville	161	50 MVAR				100		C
5/1/2001	ITWG	Capacitor	MEC Forest & Vermont	161	50 MVAR				100		C
10/1/2000	MB	Capacitor	Brookings	115	20x2	100					C
10/1/2000	MB	Capacitor	Jamestown	115	40	100					C
6/1/2000	NEBRASKA	Capacitor Banks	East Columbus	34.5	10.8 MVAR x2	1					C
12/1/2000	NEBRASKA	Reactor Bank (Series)	Leeds	161	20 MVAR	1					C
6/1/2001	NEBRASKA	Capacitor Bank	Schuyler	115	21 MVAR	1					C
6/1/2001	NEBRASKA	Capacitor Bank	33rd & Superior	115	50 MVAR	1					C
6/1/2001	NEBRASKA	Capacitor Bank	Hickok	115	12 MVAR x2	1					C
11/1/1999	RRV	Capacitor	Rugby Area	115	20 MVAR	100					C
6/1/2000	RRV	Capacitor	Long Prairie	115	1 x 27 MVAR	100					C
3/31/2000	UMV	Capacitors	Elk	69	5.1 MVAR	100					C
4/30/2000	UMV	Capacitors	Heron Lake	69	12.0 MVAR	100					C
5/1/2000	UMV	Capacitors	Paynesville	115	2 X 20 MVAR	100					C
12/1/2000	UMV	Capacitors	Stone Lake	161	2-20 MVAR	100					C
12/1/2000	UMV	Capacitors	Scott Co	115	60 MVAR	100					C
5/1/2001	UMV	Capacitors	Crystal Cave	161	2 x 40 MVAR						C
5/1/2001	UMV	Capacitors	Wilson	115	120 MVAR	100					C
9/1/2001	UMV	Capacitors	Burnsville	115	60 MVAR	100					C

Section 5. TPSC Observations and Conclusions

This update to the December 29, 2000 "MAPP Regional Plan 2000 through 2009" confirms the original importance of two major transmission needs reported in the 2000 Regional Plan:

- Increased MAPP to MAIN capacity:

  Manifested by the Arrowhead (at Duluth, Minnesota) to Weston (at Wausau, Wisconsin) 345 kV line as updated in the UMV Section, and

- Increased MAPP to SPP capacity:

  Pending specific recommendations from a study team that has been created in accordance with recommendations in the 2000 Regional Plan

The concepts of these two needs are geographically depicted in Figure 5-1. Continued reviews of OASIS reservation refusal service requests has confirmed the previous conclusion that an expansion plan needs to include improvements in each area. This is because a majority of constrained reservations are due to the simultaneous limits between MAPP-MAIN and MAPP-SPP. Therefore, implementing an expansion project targeted at one interface alone will only provide increased transfer capability for a small set of circumstances. The mutual benefit (quantified by reducing the "yellow" portion of the bars in Figure 2.5-8) can only be realized if expansion proceeds on both interfaces. In contrast, completing expansion along only one interface would only reduce a portion of the "green" section of the bars in Figure 2.5-8.

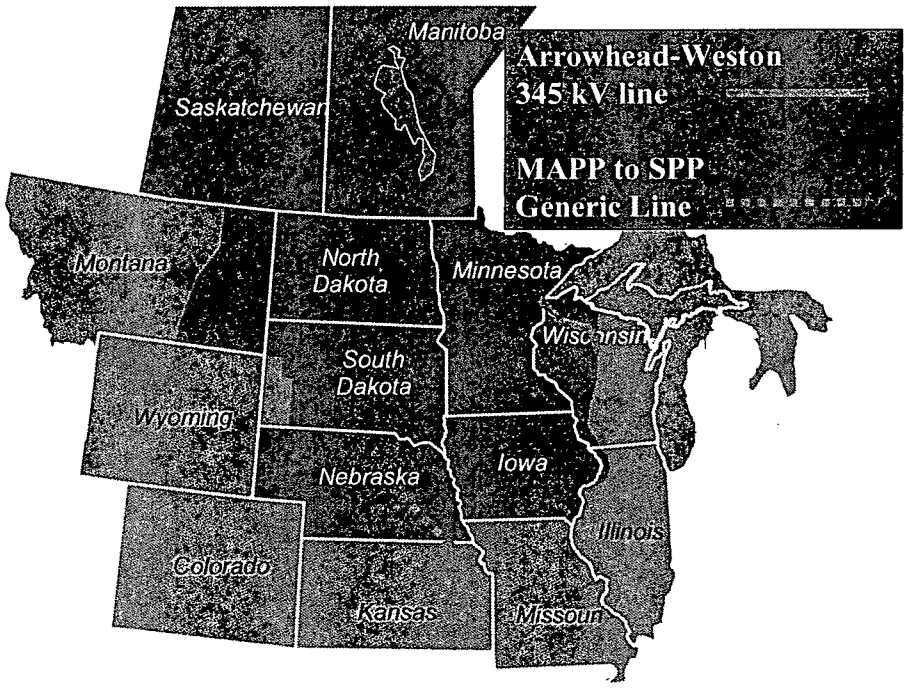

Figure 5-1. Two Major Transmission Needs and Solutions

Besides confirming the original need to improve export capability over these two major interfaces, recent OASIS transmission request review since the 2000 Regional Plan was issued has shown that the need is now bi-directional. That is, the recent tracking has also shown transmission constraints (via TLR and refused OASIS reservations) in MAPP import capability. The area of bi-directional constraint is shown on Figure 2.5-1. To date these constraints have only hampered transporting cost effective generation to MAPP load. However, these constraints are a good indicator of limited reliability sharing between regions in the future. To date, more costly generation has been brought into service and reliability has been maintained. Without increased interregional transmission tie capacity, the constraints are likely to evolve to firm curtailments when generation is not available on the receiving side of the constraint. Providing long-term reliability by maintaining higher generation reserves on both sides of the bi-directional transmission constraint would be more costly to consumers located on both sides.

The open access environment fostered by FERC Orders 888 and 889 have created a demand for transmission capacity at certain interfaces that far exceeds the capability for which the system was designed. Furthermore, this demand appeared to be short term or seasonal in nature. While the majority of this demand is still due to short-term requests, the more recent OASIS review shows a large increase in the number of requests for long-term transmission service that is being refused.

In recent years, siting of gas-fired and wind generation has taken advantage of surplus transmission capability by utilizing local transmission outlet solutions. Consequently, there have been no large transmission projects constructed to enhance the transmission capability to move power across the MAPP region. However, this update to the 2000 Plan now shows a 345 kV transmission addition in southwest Minnesota that will enhance wind outlet capability. Previously, only additions at 115 kV or lower had been related to accommodating wind generation outlet.

This update provides more certainty to the location of future generation than the previous siting review conducted in the 2000 Plan. In comparison, this 2001 update reflects 2972 MW (up from 188 MW) as completed in the most recent two years, and 6786 MW (up from 4381) sited by nine years into the future. While the amount that is "site unknown" nine years into the future remains about the same at 2704 MW (up from 2514 MW) this is a smaller percentage of all future generation reported.

In addition to this "2001 Update to the 2000 Regional Plan", the TPSC is working on the development of a transmission "Vision Plan". This Vision Plan will consist of a collection of concept level transmission plans that address future generation outlet to load, and relief of existing transmission constraints in the MAPP region.

Future goals that the TPSC plan to address in the next plan for the MAPP region include:

- Definition of MAPP simultaneous export capability enhancement available from a proposed MAPP-SPP transmission project, and
- Quantification of MAPP simultaneous import capability.

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Exhibit CWK-1

Selected Gas Utility Companies
Data for Most Recent Calendar Year

Selected Gas Distribution Companies		A Market Price per Share Olson, Schedules 4 and 11	B Book Value per Share Olson, Schedules 4 and 11	C Market/Book Ratio Olson, Schedules 4 and 11	D Earnings Per Share Zacks Investment Research	E % Earnings to Mkt Price ~~E/A~~ D/A	F % Earnings to Book Val. E/B D/B
AGL Resources, Inc	ATG	19.62	11.46	1.71	1.24	6.3%	10.8%
KeySpan Corp.	KSE	37.28	20.51	1.82	2.41	6.5%	11.8%
Leclede Gas Co.	LG	21.97	14.99	1.47	1.37	6.2%	9.1%
Northwest Natural Gas	NWN	24.56	17.42	1.41	1.77	7.2%	10.2%
Peoples Energy Corp.	PGL	39.09	22.02	1.78	2.71	6.9%	12.3%
Vectren Corp.	VVC	21.91	11.59	1.89	1.77	8.1%	15.3%
WGL Holdings	WGL	27.72	15.31	1.81	1.77	6.4%	11.6%
Average						6.8%	11.6%
Selected Combination Companies							
Ameren Corp.	AEE	40.50	23.75	1.71	3.28	8.1%	13.8%
Energy East Corp.	EAS	20.72	15.24	1.36	2.04	9.8%	13.4%
Puget Sound Energy Corp	PSD	24.94	16.27	1.53	2.04	8.2%	12.5%
Wisconsin Energy Corp	WEC	20.44	17.16	1.19	1.57	7.7%	9.1%
WPS Resources	WPS	34.31	20.55	1.67	2.53	7.4%	12.3%
Average						8.2%	12.2%

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Selected gas utilities companies data for most recent calendar year by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 12
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

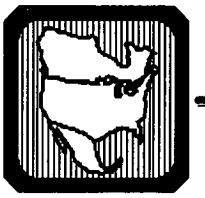
Reliability Assessment

2001–2010

The Reliability of

Bulk Electric Systems

in North America



North American Electric Reliability Council

October 16, 2001

EXHIBIT
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Reliability Assessment, 2001-2010
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 11
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

MAPP

Planned resources in the MAPP-U.S. area are judged to be inadequate to supply the forecast annual summer peak demand growth through the next ten years. When demand forecast uncertainty is taken into account, the Region may be capacity deficient by 2004 summer and nearly 5,442 MW deficient by 2010 summer. MAPP-U.S. utilities have committed to provide an additional 5,018 MW of capacity during this period. Most utilities in the Region propose to install natural gas-fired combustion turbines with short construction lead-time to meet capacity obligations.

In general, the MAPP transmission system is adequate to meet the needs of the member systems and will continue to meet reliability criteria through the planning period. Because of the tremendous increase in power marketing activity, however, the system is expected to continue to operate near its secure limit. Current studies at MAPP have also identified potential restrictions that may limit energy transfers from the Twin Cities (Minneapolis-St. Paul) area to Iowa and Wisconsin.

MAPP Assessment Process

The MAPP Reliability Council and Regional Reliability Committee direct the annual assessment of adequacy and security through the Council's working group structure. The Transmission Reliability Assessment, Composite System Reliability, and Model Building Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies, Design Review, and Operating Review Subcommittees are committed to reviewing MAPP reliability from near-term and long-term perspectives to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 2000 summer non-coincident peak demand was 32,411MW, a 0.4% decrease over 1999, without ALTW-CIPC, and 7.3% below the 2000 forecast (34,952 MW). Alliant-West and CIPCo have moved out of the MAPP Region and into the MAIN Region.

MAPP-Canada was 1.6% above the 1999 actual demand and 7.4% below the 2000 forecast.

MAPP-U.S. accounted for 0.8% below 1999 actual demand and 7.3% below the 2000 forecast. The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.9% per year during the 2001–2010 period, as compared to 1.6% predicted last year for the 2000–2009 period. The MAPP-U.S. 2010 non-coincident summer peak demand is projected at 33,286 MW. This projection is 2.8% below the 2009 non-coincident summer peak demand predicted last year.

Annual electric energy usage for MAPP-U.S. in 2000 (145,981 GWh) was 9.8% above 1999 consumption and 1.2% above the 2000 forecast.

Resource Assessment

Generating system adequacy for MAPP-Canada will be adequate over the ten-year period. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-Canada area will have capacity surplus of nearly 1,326 MW by 2010 summer.

The MAPP-U.S. Region is judged to be inadequate over the 2001–2010 period. Net capacity for MAPP-U.S. (committed and proposed generation additions, uprates, and retirements) will provide an additional 5,018 MW of capacity in the MAPP-U.S. area for 2001–2010. Committed and proposed capacity additions (new) account for 2,525 MW, uprates account for 2,605 MW, and retirements accounts for 79 MW. The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15%, which is equivalent to a 13.04% minimum capacity margin requirement. The summer reserve margin is expected to be below the 2000 forecast and to decline from a high of 20% in 2001 to 15% in 2005 and 1% in 2010 when committed and proposed generation is considered. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-U.S. area may be capacity

deficient by 2004 summer and nearly 5,442 MW deficient by 2010 summer.

Because of the potential generating system inadequacy, MAPP must plan for additional resources and carefully watch construction lead times to ensure that enough resources will be available to maintain Regional adequacy. The ability to import power may be severely limited in the near term because of the lack of external resource availability.

Transmission Assessment

The existing transmission system within MAPP-U.S. is comprised of 7,239 miles of 230 kV, 5,742 miles of 345 kV, and 342 miles of 500 kV transmission lines. MAPP-U.S. members plan to add 229 miles of 345 kV and 605 miles of 230 kV transmission in the 2001–2010 time frame. The MAPP-Canada existing transmission system is comprised of 4,578 miles of 230 kV and 130 miles of 500 kV transmission lines. MAPP-Canada is planning for an additional 59 miles of 230 kV transmission in the 2001–2010 time frame.

MAPP member systems continue to plan for a reliable transmission system. Coordination of expansion plans in MAPP takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission owning members, transmission-using members, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the five subregional planning groups, has prepared the MAPP Regional Plan, 2000 to 2009, to address the needs of all stakeholders.

In general, the MAPP transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the ten-year transmission plan are implemented. However, MAPP continues to monitor the thirteen transmission constraints within the Region that limit MAPP exports. Current studies at MAPP have identified potential restrictions on the transmission system for outages of certain 345 kV tie lines connecting the Twin Cities metropolitan area of Minneapolis-St. Paul to Iowa and Wisconsin area, such as Prairie Island-Byron or King-Eau Claire. These outages may result in system stability restrictions that continue to limit energy transfers from the Twin Cities to Iowa and Wisconsin.

A transmission system limitation was recently identified in the eastern North Dakota-northern Minnesota area that will limit the ability to meet firm obligations in and through the area during winter peak conditions. A study is currently being conducted that will identify and recommend transmission system alternatives.

MAPP has seen a tremendous increase in power marketing activity resulting from open access and available low cost energy in the Region. This high level of activity has stretched the existing transmission system to its reliability limits to take advantage of market opportunities. MAPP members will continue to take a proactive role in the planning and operation of the system in a secure and reliable manner.

Operations Assessment

The MAPP Security Center has been fully operational with the implementation of real-time system monitoring of key flowgates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Operating Review Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and scheduled transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the Region through the sharing of generation during system emergencies.

The Mid-Continent Area Power Pool (MAPP) membership includes 104 utility and non-utility systems. The MAPP Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is 900,000 square miles with a population of 18 million.

MONTANA-DAKOTA UTILITIES CO.
POOL SALES CALCULATION

	ACTUAL DATA						2002 PROJECTED		
	On-Peak Sales (Mwh)	Off-Peak Sales (Mwh)	Total Sales (Mwh)	Total Sales Revenue	Margin	Actual Fuel Cost per Mwh	Fowards On-Peak Price 1/	2002 Est. Off-Peak Price	2002 Margin Estimate
Jan-02	47,691	45,273	92,964	$1,644,146	$621,897	11.00			$ 621,897 2/
Feb-02 3/			48,328	830,017	319,180	10.57			$ 319,180 3/
Mar-01	52,292	43,693	95,985	2,600,162	1,564,642	10.79	21.80	12.00	$ 628,761
Apr-01	39,727	40,154	79,881	2,193,183	1,335,859	10.73	22.00	12.00	$ 498,518
May-01	27,343	23,548	50,891	1,345,245	459,452	17.41	25.80	12.50	$ 114,007
Jun-01	28,866	18,586	47,452	2,088,900	1,396,597	14.59	31.10	12.50	$ 437,755
Jul-01	32,476	26,985	59,461	3,582,253	2,640,279	15.84	40.50	13.00	$ 724,109
Aug-01	37,571	29,082	66,653	4,066,038	2,969,765	16.45	33.00	13.00	$ 521,635
Sep-01	37,593	36,413	74,006	1,437,175	644,063	10.72	23.80	12.50	$ 556,764
Oct-01	44,942	35,572	80,514	1,575,604	591,734	12.22	22.60	12.00	$ 458,683
Nov-01	46,911	33,155	80,066	1,530,192	639,113	11.13	22.60	12.00	$ 566,970
Dec-01	42,721	42,517	85,238	1,556,362	648,503	10.65	24.10	12.00	$ 631,921
Total	438,133	374,978	861,439	24,449,278	13,831,083				**$ 6,080,199**

1/ Based on 2002 IntercontinentalExchange (ICE) Forward contracts
2/ Actual for January 2002
3/ Actual for February 1st through February 14th, times two to reflect full month.

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2/24/02

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MDU Pool Sales Calculation
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 10
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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Table 1, Prices & Intercontinental Exchange Forward Electricity Prices by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 9
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Table 1
Prices and Intercontinental Exchange Forward Electricity Prices

Delivery Period	NYMEX Futures Strip ($/MWh)	Intercontinental Exchange Forward Prices ($/MWh)	Difference - Forward prices minus NYMEX Futures Prices ($/MWh)
March, 2002	$21.10	$21.80	$0.70
April, 2002	$31.60	$22.00	-$9.60
May, 2002	$24.70	$25.80	$1.10
June, 2002	$30.00	$31.10	$1.10
July, 2002	$38.25	$40.50	$2.25
August, 2002	$38.25	$33.00	-$5.25
September, 2002	$22.90	$23.80	$0.90
October, 2002	$22.90	$22.60	-$0.30
November, 2002	$22.90	$22.60	-$0.30
December, 2002	$22.90	$24.10	$1.20
Average for 10 Month Period	***$27.55***	***$26.73***	***-$0.82***

Note:
1) Prices quoted are for On-Peak Periods for delivery at Cinergy trading hub.
2) NYMEX quotes as of February 16, 2002
3) Intercontinental Exchange (ICE) forward price quotes as of February 16, 2002

EXHIBIT
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2/25/02

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JANUARY 22, 2002
CASE NO. PU-399-01-186

Request No. 5:

Refer to page 15, line 7: Explain why a model that assumes that the next dividend will be received today results in a multiplication of the dividend yield by (1 + .5g). Conversely, explain why the multiplication of the dividend yield by (1 + 5g) implies that the next dividend will be received today.

Response:

Please see Attachment A for a description of the derivation of the 0.75g multiplier. The derivation of the 0.5 multiplier is identical, except that it (i) moves the timing of each dividend forward one-quarter by subtracting 0.25 from the exponent in the denominator of each term in equation (1), and (ii) does not contain the (1+g) factor in the numerator until the third term in the equation.

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Response to Data Request No. 5
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 8
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

EXHIBIT
8
2/25/02

Incorporating the assumptions that "the next dividend increase is a half year away" and the next dividend is one quarter away in the constant growth DCF model means that the current market price of a share of common stock would be:

$$P_0 = \left[\frac{D_0}{4(1+k)^{.25}} + \frac{D_0(1+g)}{4(1+k)^{.5}} + \frac{D_0(1+g)}{4(1+k)^{.75}} \right.$$

$$+ \frac{D_0(1+g)}{4(1+k)} + \frac{D_0(1+g)}{4(1+k)^{1.25}} + \frac{D_0(1+g)^2}{4(1+k)^{1.75}}$$

$$\left. \ldots + \frac{D_0(1+g)^{\infty}}{4(1+k)^{\infty}} \right] \qquad (1)$$

where,

k = the annual cost of common equity capital;

D_0 = the current annual dividend (most recent quarterly dividend multiplied by four);

P_0 = the current price per share; and

g = the expected annual dividend growth rate.

Employing the same algebraic steps used in deriving the annual dividend model results in the following DCF model:

$$k = \frac{D_0}{4P_0}[(1+k)^{.75} + (1+g)(1+k)^{.5} + (1+g)(1+k)^{.25} + (1+g)] + g \quad (2)$$

Equation (2) assumes that the next dividend at the current rate will be received in three months, or one-quarter year. The $(1+k)^{.75}$ term in brackets is associated with this first dividend. The second dividend is assumed to be received in six months, or one-half year. This dividend also includes the annual dividend increase, hence, the second term in brackets is $(1+g)(1+k)^{.5}$.

The investor required rate of return estimated using equation (2) overstates the required rate of return for ratemaking since it includes the return that investors expect to earn during part of the year by reinvesting the dividends received in the first three quarters of the year. In other words, equation (2) describes investors' effective market required rate of return, k_{mkt}. The required rate of return estimated using this model includes the partial year return which investors have an opportunity to earn on their own by reinvesting the first three quarterly dividends. The portion of the effective market rate of return that is associated with dividend reinvestment is:

$$k_{div} = \frac{D_0}{4P_0}\{[(1+k)^{.75} -1] + (1+g)[(1+k)^{.5} -1] + (1+g)[(1+k)^{.25} -1]\} \quad (3)$$

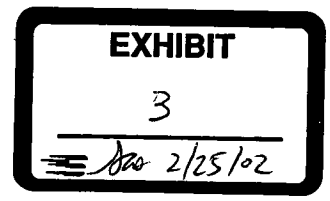
Subtracting equation (3) from equation (2) yields the following required ratemaking rate of return, k_{reg}:

$$k_{mkt} - k_{div} = \frac{D_0}{4P_0}[1 + (1+g) + (1+g) + (1+g)] + g$$

$$= \frac{D_0}{P_0}[1+.75g] + g. \quad (4)$$

MDU Electric Operations

PSC Staff Presentation
Case No. PU-399-01-186
February 25, 2002



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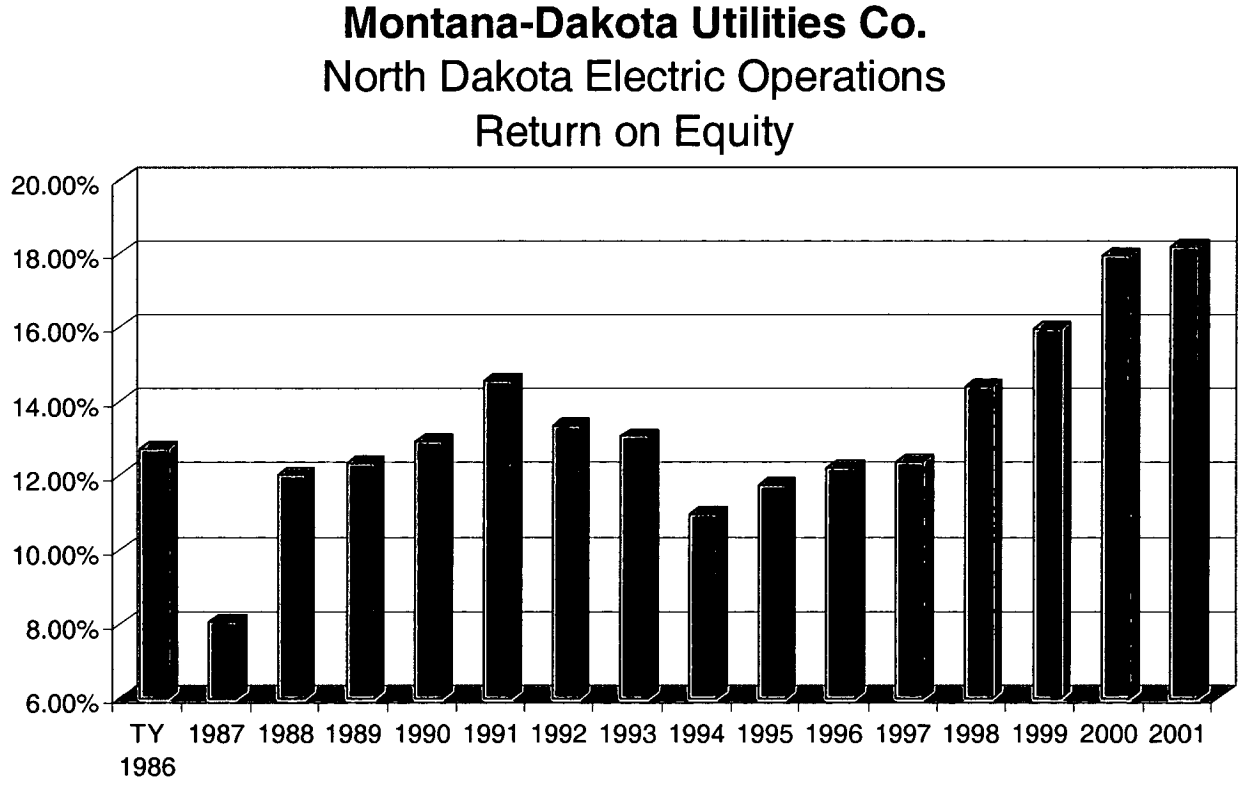
PSC Staff Presentation
by Public Service Commission
Exhibit # 3
02/25/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Brief History

- Last electric rate case was filed in 1986 resulting in a 6.37% rate increase.

- Recent earnings are too high for a regulated monopoly service provider.



Test Year

- Staff's direct testimony filed on September 7, 2001 utilized a 2000 historical test year plus additional off-system sales margins for an excess earnings position of $9.155 million.

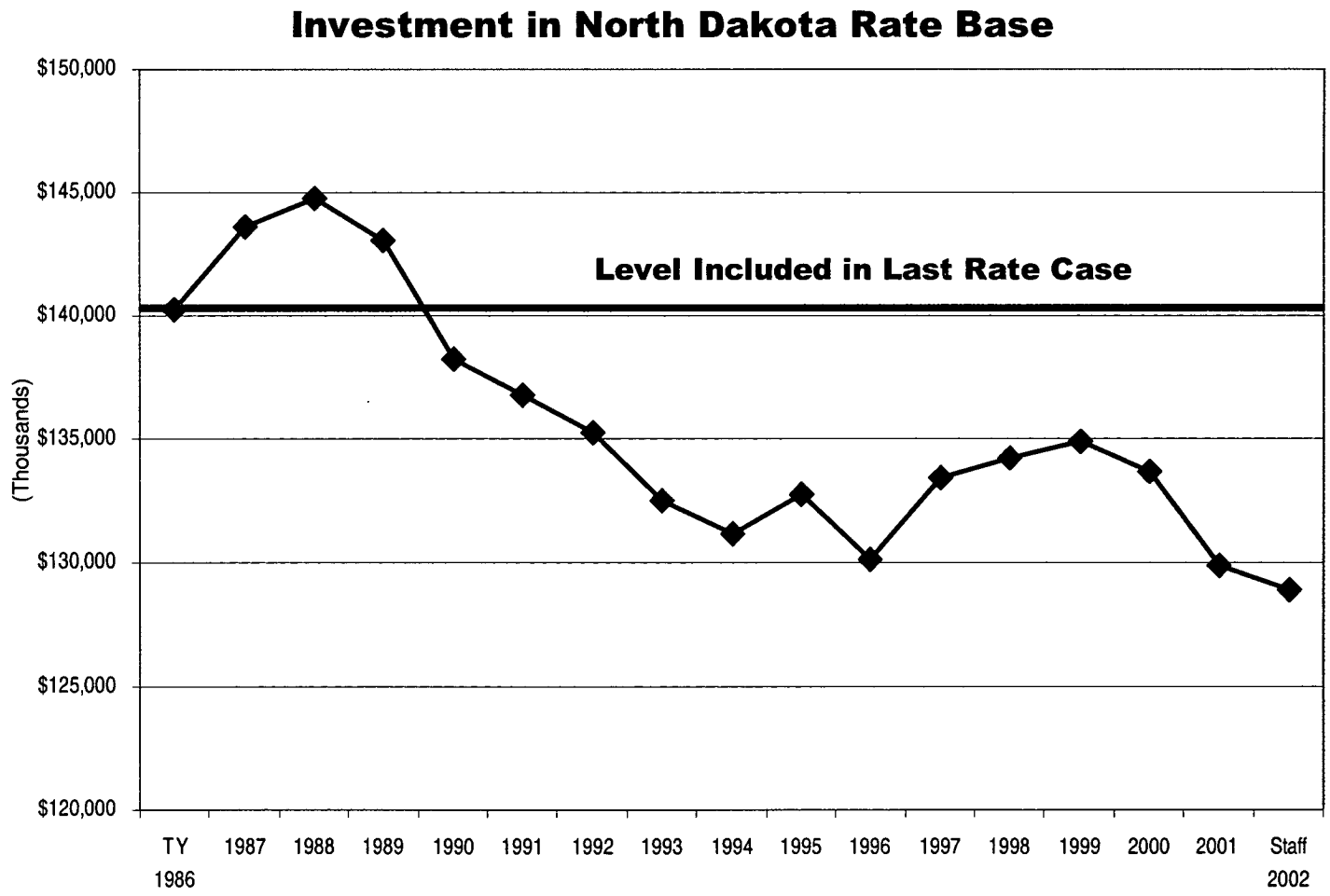
- 2001 results were received January 30, 2002 yielding a return similar to that of 2000.

- Staff rebuttal testimony gives consideration to the new 2001 test year information and MDU's testimony effectively moving the test year to 2002 and beyond. Staff reduced its original position to a finding of excess earnings of $7.3 million.

Profit Regulation Components

- Rate Base
- Rate of Return
- Net Regulated Income

Rate Base History



Rate Base Summary

- In rebuttal testimony, staff updated rate base for 2001 financial information and accepted all of MDU's adjustments to rate base for extraordinary capital costs.

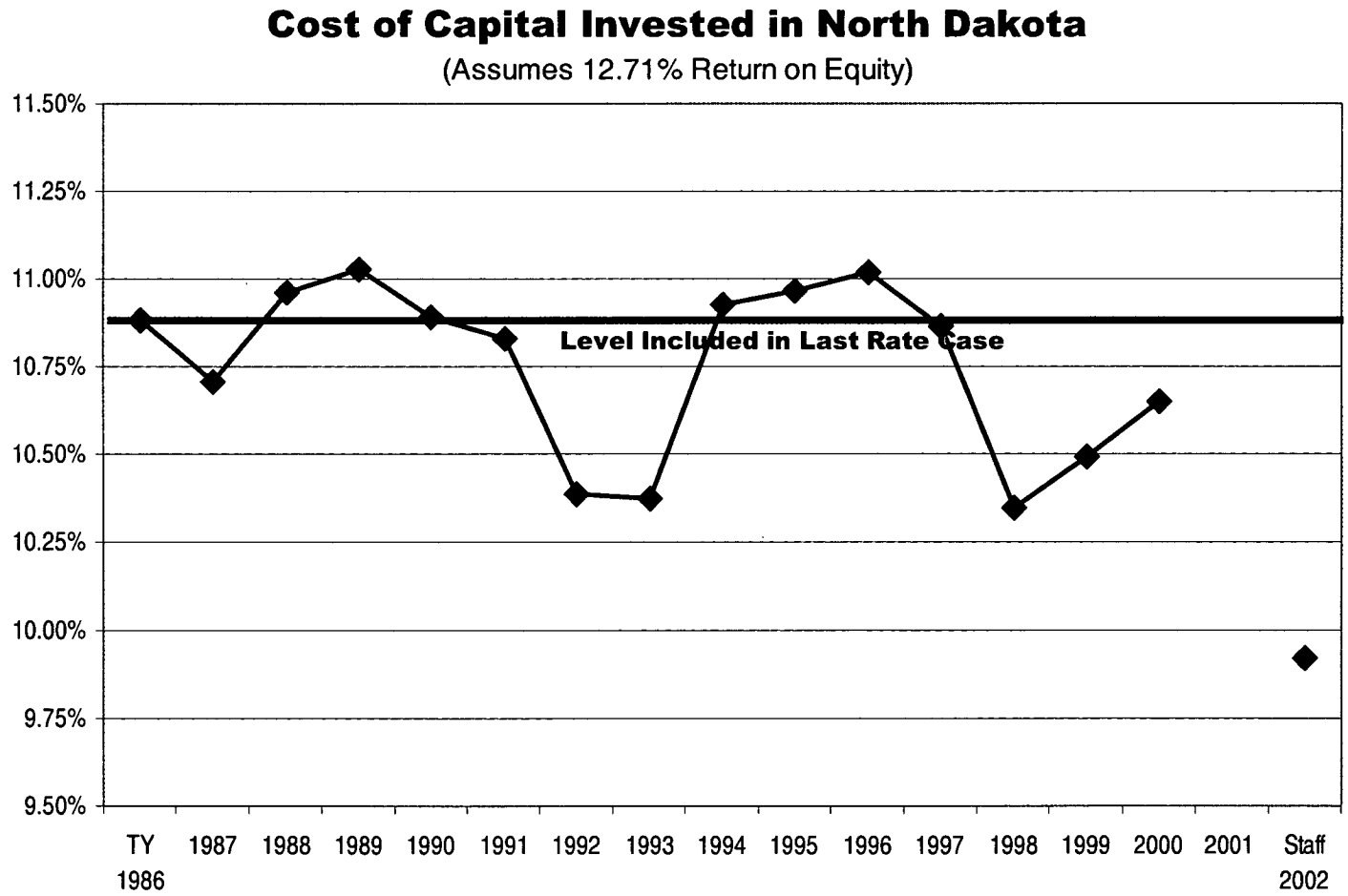
- In surrebuttal testimony, MDU accepted staff's rate base.

MDU and Staff Rate Base

	(Thousands)			
	Beginning		Ending	Average
Description	Balance	Adjustments	Balance	Balance
Plant in Service	$379,126	$4,325	$383,451	$381,289
Accum. Res. for Depreciation	215,094	71	215,165	215,130
Avg. Net Plant in Service	$164,032	$4,254	$168,286	$166,159
Constr. Work in Progress	518		518	518
Materials & Supplies	2,909		2,909	2,909
Fuel Stocks	1,255		1,255	1,255
Prepayments	99	15	114	107
Net Negative Salvage			0	-
Accum. Def. Income Taxes	(39,774)	(65)	(39,839)	(39,807)
Accum. Invest. Tax Credits	(2,229)		(2,229)	(2,229)
Customer Advances	(10)		(10)	(10)
Average Rate Base	$126,800	$4,204	$131,004	$128,902

Required Return on Investment

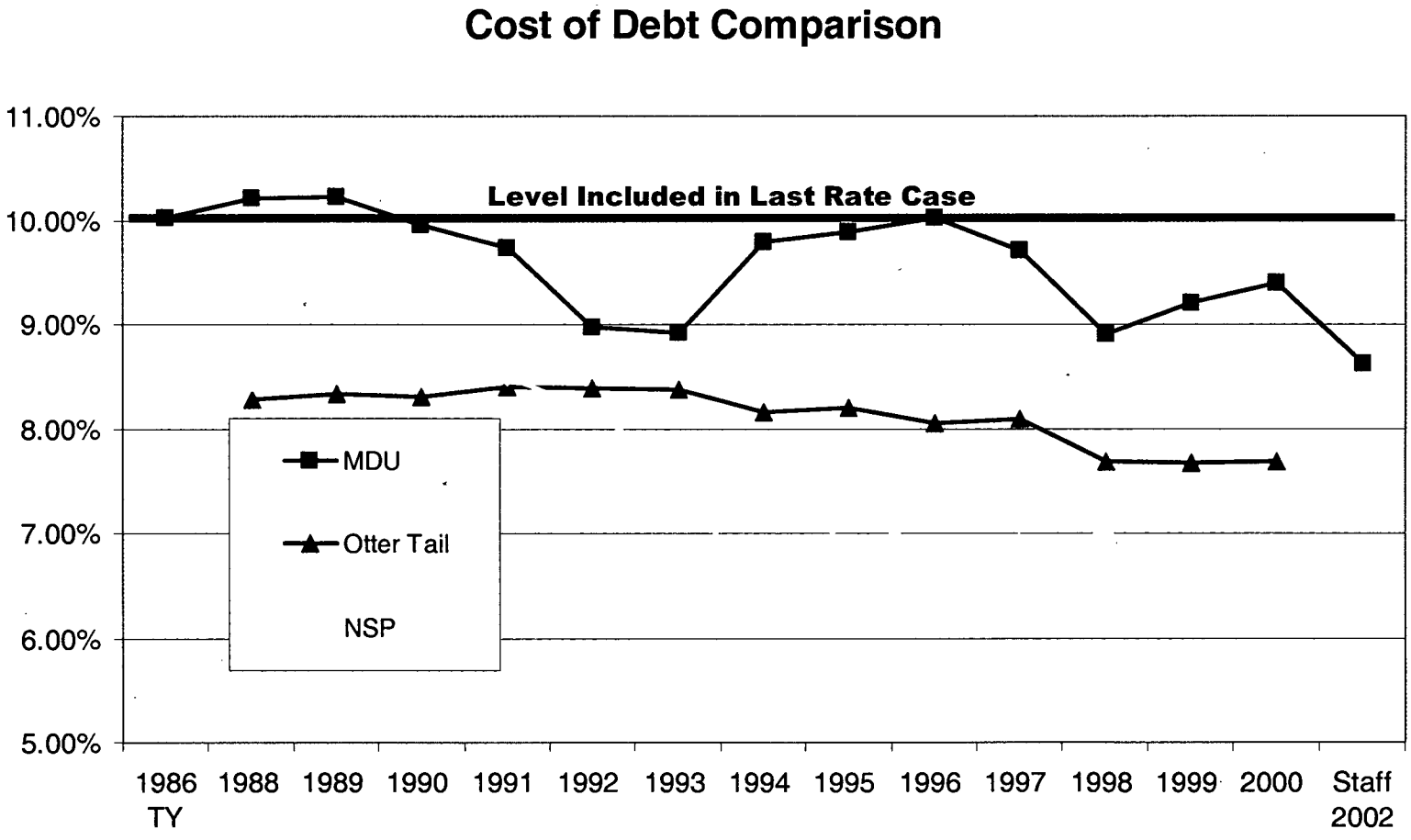
- Common Equity
- Preferred Equity
- Long-Term Debt



Cost of Capital Summary

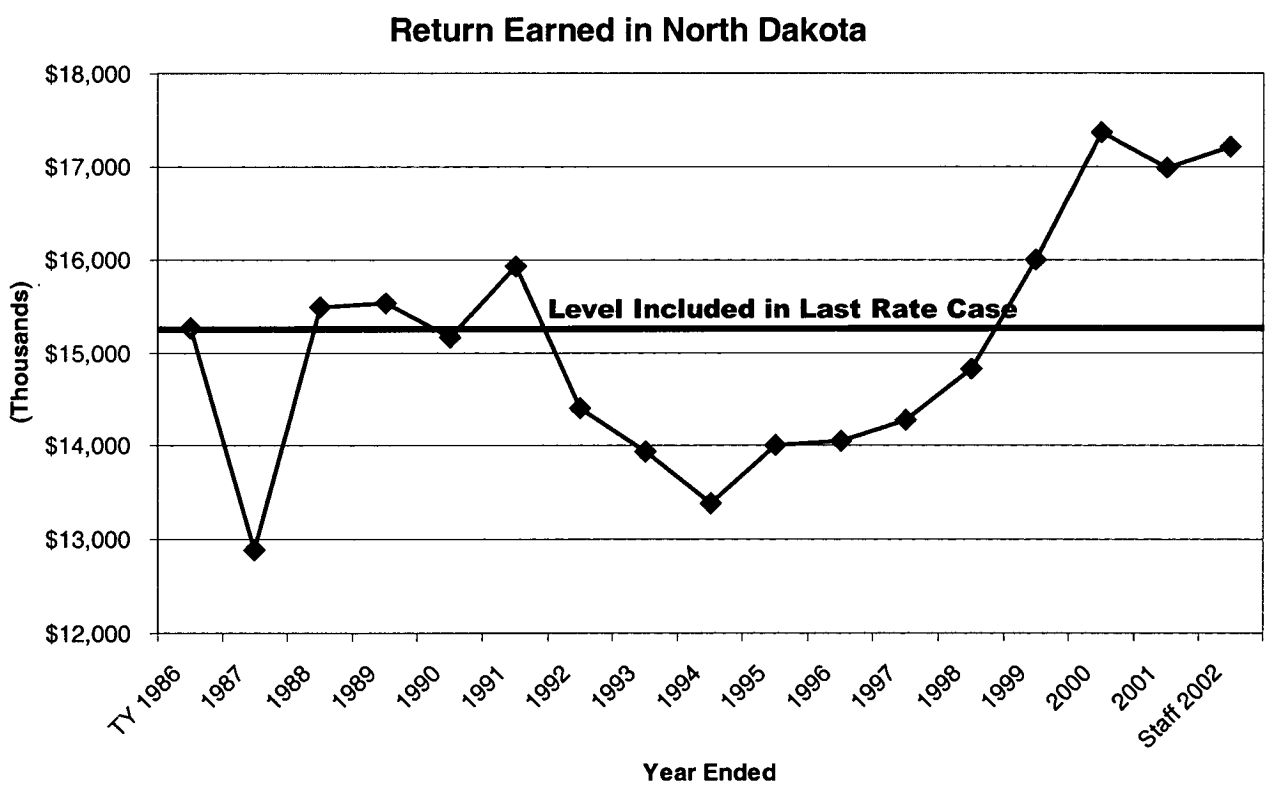
	Staff		
	Capital		Weighted
Description	Ratio	Cost	Cost
Debt	45.90%	8.62%	3.96%
Preferred Stock	5.23%	4.63%	0.24%
Equity	48.87%	11.70%	5.72%
Total	100.00%		9.92%
	Montana-Dakota Utilities Co.		
	Capital		Weighted
Description	Ratio	Cost	Cost
Debt	45.90%	9.22%	4.23%
Preferred Stock	5.23%	4.63%	0.24%
Equity	48.87%	12.75%	6.23%
Total	100.00%		10.70%

Long-Term Debt



Net Regulated Income

- Revenues
- Expenses
- Net Income



Revenues

- Retail Sales
- Sales for Resale
- Other Revenue

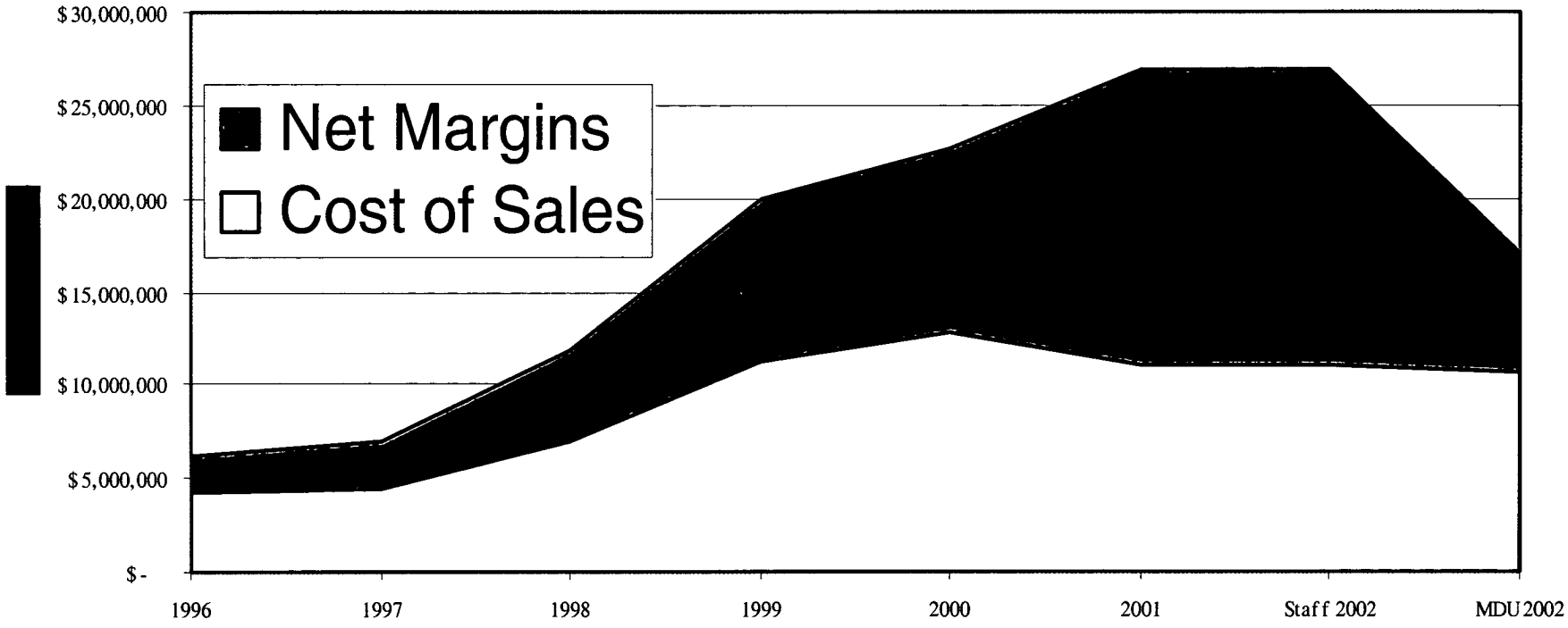
Retail Revenues

- MDU does not calculate the impact of weather on retail sales.

- North Dakota net margins (revenues less production expense) excluding off-system sales are $1.1 million down in 2001 compared to 2000.

- No adjustment.

Resale Margins



Why the Difference?

- Staff relies on actual results
- MDU relies on future projections

Factors Affecting Future Resale Margins

- Futures Contracts
- Natural Gas Prices
- Droughts
- National Economy
- Manufacturing Industry
- New Generation Capacity
- Natural Gas Supplies

Factors Affecting Future Resale Margins (Continued, Page 2)

- Weather
- Natural Gas Transportation Rates
- Incremental Operating Costs
- Transactional Risks
- Fuel Cost Differentials
- Transmission Constraints
- Generation Mix

Factors Affecting Future Resale Margins (Continued, Page 3)

- Transmission Access
- Market Power of Supplier
- Institutional Inefficiencies
- Regulation Uncertainties
- Stranded Cost Exposure
- Plant Outages
- Incomplete Market Information

Factors Affecting Future Resale Margins (Continued, Page 4)

- Nuclear Safety Regulations
- Hedging Activities
- Spark-Spreads
- Conservation Programs
- Gas Exploration Levels
- Gas in Storage
- Market Uncertainty

Proposal to Settle Resale Issue

- The uncertainties of the future warrants the consideration of actual results as a proxy for future rates.

- The resulting rates in this proceeding may be in effect for 15 years. Using an average of recent results will smooth out recent market fluctuations and provide for a normalized level going forward.

- Staff suggests the commission consider using an average of sales margins during the past 3 years for purposes of rate design in this proceeding.

Resale Settlement Calculation

Description	Total
1999 Resale Margins	$ 8,772,849
2000 Resale Margins	9,918,345
2001 Resale Margins	15,937,892
Add-back Demand Penalties	457,836
Total	$ 35,086,922
3 Year Average	$ 11,695,641
2001 Resale Margins	15,937,892
Total Company Adjustment	$ (4,242,252)
N.D. Share	66%
N.D.Adjustment	$ (2,799,886)

Expense Issues Remaining

- Demand Penalty – The penalties for non-compliance with MAPP reserve requirements should not be included as a ratemaking expense. However, can agree that the cost of securing additional capacity for compliance should be included in the cost of service.

- A & G Costs – Requires a closer look.

Administrative & General Expenses

Total Company (Thousands)							
Account Description	1996	1997	1998	1999	2000	2001	MDU
Salaries	$3,990	$4,116	$4,070	$4,118	$4,181	$5,024	$5,024
Office Supplies	1,883	1,903	1,812	2,112	2,122	2,906	2,906
Outside Services	545	521	558	687	677	653	653
Property Insurance	238	216	202	200	244	344	590
Injuries & Damanges	748	694	639	639	576	474	474
Employee Pen. and Ben.	5,796	4,384	4,410	3,484	2,451	2,415	3,883
Regulatory Commission	125	60	59	66	161	3	3
General Advertising	5	13	18	18	116	195	195
Misc General	789	725	862	830	1,094	978	978
Rents	55	50	35	38	40	124	124
Maintenance of Gen Plant	600	606	627	654	692	772	772
Total A & G Expense	$14,774	$13,288	$13,292	$12,846	$12,354	$13,888	$15,602
Percent Change		-10.1%	0.0%	-3.4%	-3.8%	12.4%	12.3%

Remaining A & G Issues

- Office Supplies
- Insurance Expense
- Pensions & Benefits
  - Pension Expense
  - FAS 106
  - SISP

Office Supplies Expense

- Automobile Service
- Bank Charges
- Books & Subscriptions
- Building Service
- Communications
- Office Equipment
- Computer Infrastructure
- Membership Fees
- Office Supplies
- Legal Department Expenses
- Postage and Printing
- Meals, Travel and Incidental Expenses
- Corporate Aircraft

Office Supplies Summary

- Office supplies expenses are controllable expenditures.
- MDU's surrebuttal testimony does not provide an analytical approach to quantifying future estimated costs.
- Staff's position remains unchanged.

Insurance Expense

- Property Insurance
  - Cost of insurance or reserve accruals to protect against losses to property.
- Injuries and Damages
  - Cost of insurance or reserve accruals to protect against damage claims of employees or others not covered by insurance.

Insurance Expense Summary

- MDU's surrebuttal testimony does not include a review of all insurance expenditures and is inconclusive.
- Staff's position remains unchanged.

Pension and Post Retirement

- MDU's surrebuttal testimony does not include a review of all employee pension and benefits expenditures and is inconclusive.

- Staff's position remains unchanged.

SISP

- Double pension for "key employees"
- Enron debacle
- Front page principle
- Beneficiaries
- Mergers and Acquisitions

- Staff's position remains unchanged

Summary of Net Regulated Income Adjustments

Description	Amount	Account	
Reduce Sales for Resale Margins	($2,800)	Revenue	
3 Year Amortization of AVS Maint.	(635)	Production	
Eliminate Demand Penalties	(316)	Production	
Add Additional Capacity	186	Production	
Eliminate Schedule F Revenues	370	Transmission	
Energy Share & Lignite Council Dues	33	A & G	
Normalize Office Supplies Expense	(447)	A & G	
Depreciation for Plant Additions	77	Depreciation	
Adjust Income Tax Expense	(852)	Income Tax Expense	
Reduce Net Regulated Income	($1,216)		

Net Regulated Income Statement

	(Thousands)				
	Reported by MDU				
Description	1999	2000	2001	Adjustments	Test Year
Sales for Resale	$13,265	$15,034	$17,687	($2,800)	$14,887
All Other Revenues	80,657	81,929	84,415	0	84,415
Total Revenues	$93,922	$96,963	$102,102	($2,800)	$99,302
Production Expense	$37,160	$38,365	$40,671	($765)	$39,906
Transmission Expense	3,667	3,567	3,915	370	4,285
Distribution Expense	4,586	4,660	5,010	0	5,010
Customer Accounts	2,162	2,113	2,233	0	2,233
Customer Service & Info.	96	105	113	0	113
Sales Expense	258	269	281	0	281
Administration & General	8,303	8,154	8,968	(414)	8,554
Total O & M Expense	$56,232	$57,233	$61,191	($809)	$60,382
Depreciation	$11,436	$11,803	$11,955	$77	$12,032
Taxes Other Than Income	$3,936	$3,811	$4,019	$0	$4,019
Income Tax Expense	$6,319	$6,750	$7,955	($852)	$7,103
Net Regulated Income	$15,999	$17,366	$16,982	($1,216)	$15,766
Income Tax Calculation:					
Net Income Before Taxes	$22,318	$24,116	$24,937		$22,869
Less Interest Deduction:					
Rate Base	$134,869	$133,667	$126,800		$128,902
Weighted Cost of Debt	4.93%	4.74%	3.96%		3.96%
Calculated Interest Deduction	$6,644	$6,332	$5,017		$5,101
Other Tax Adjustments	$281	($743)	$163		$163
Taxable Income	$15,955	$17,041	$20,083		$17,931
Combined Tax Rate	39.61%	39.61%	39.61%		39.61%
Income Tax Expense	$6,319	$6,750	$7,955		$7,103

Staff Revenue Excess Calculation

	(Thousands)				
	Reported				
Description	1999	2000	2001		Test Year
Average Rate Base	$134,869	$133,667	$126,800		$128,902
ROR Required (11.7% ROE)	10.07%	10.20%	9.92%		9.92%
Return Required	$13,575	$13,627	$12,574		$12,783
Return Earned	$15,999	$17,366	$16,982		$15,766
Return (Excess)	($2,424)	($3,738)	($4,408)		($2,984)
Tax Factor	1.656	1.656	1.656		1.656
Revenue (Excess)	($4,014)	($6,191)	($7,300)		($4,941)

Worksheet for Commission (1 of 2)

	(Thousands)				
	Reported				
Description	1999	2000	2001		Test Year
Average Rate Base	$134,869	$133,667	$126,800		$128,902
ROR Required (11.7% ROE)	10.07%	10.20%	9.92%		
Return Required	$13,575	$13,627	$12,574		
Return Earned	$15,999	$17,366	$16,982		
Return (Excess)	($2,424)	($3,738)	($4,408)		
Tax Factor	1.656	1.656	1.656		1.656
Revenue (Excess)	($4,014)	($6,191)	($7,300)		
	Cost of Capital				
Long-Term Debt	$144,894	45.90%			
Preferred Stock	16,500	5.23%	4.63%	0.24%	
Common Equity	154,250	48.87%			
TOTAL	$315,644	100.00%			

Worksheet for Commission (2 of 2)

	(Thousands)				
	Reported by MDU				
Description	1999	2000	2001	Adjustments	Test Year
Sales for Resale	$13,265	$15,034	$17,687		
All Other Revenues	80,657	81,929	84,415	0	84,415
Total Revenues	$93,922	$96,963	$102,102		
Production Expense	$37,160	$38,365	$40,671	($765)	$39,906
Transmission Expense	3,667	3,567	3,915	370	4,285
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Sales Expense	258	269	281	0	281
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Depreciation	$11,436	$11,803	$11,955	$77	$12,032
Taxes Other Than Income	$3,936	$3,811	$4,019	$0	$4,019
Income Tax Expense	$6,319	$6,750	$7,955		
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Net Income Before Taxes	$22,318	$24,116	$24,937		
Less Interest Deduction:					
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Weighted Cost of Debt	4.93%	4.74%	3.96%		
Calculated Interest Deduction	$6,644	$6,332	$5,017		
Other Tax Adjustments	$281	($743)	$163		$163
Taxable Income	$15,955	$17,041	$20,083		
Combined Tax Rate	39.61%	39.61%	39.61%		39.61%
Income Tax Expense	$6,319	$6,750	$7,955		

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

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

RECEIVED
MAR 5 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

March 5, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-01-186

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of the Late Filed Exhibits requested at the hearing held on February 25 and 26, 2002, in the above referenced docket.

Attached are Late Filed Exhibits 16 through 20. This completes all information requested of Montana-Dakota at the hearing.

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

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

Attachments
c: D. Schulz
W. Pearce

72 PU-399-01-186 Pages: 1
Cover letter re Late Filed Exhibits 16 - 20
by Montana-Dakota Utilities Co., a Division of MDU R
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Late Filed Exhibit No. 16

Requested Information:

Provide monthly on-peak and off-peak prices for MAPP for the period 1998 through 2001.

Responses:

Please see Attachment A (also labeled as Exhibit No. ___(RJS-12).

71 **PU-399-01-186** Pages: 2

Details on monthly on-peak & off-peak prices for MAPP (1998-2001)
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # Late Filed 16
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Case PU-399-01-186
Late Filed Exhibit No. 16
Exhibit No. _____(RJS-12)

Table 1

MAPP Average Monthly On-Peak and Off-Peak Electricity Prices

($/MWh)

Year	Month	On-Peak $/MWh	Off-Peak $/MWh
1998	1	$20.58	$11.00
	2	$18.35	$12.71
	3	$24.24	$12.82
	4	$23.61	$12.53
	5	$40.19	$12.12
	6	$51.22	$11.79
	7	$104.18	$12.32
	8	$37.22	$12.69
	9	$29.12	$12.19
	10	$21.84	$12.40
	11	$24.69	$14.37
	12	$24.68	$12.13
1999	1	$24.37	$13.88
	2	$19.99	$13.90
	3	$19.96	$14.01
	4	$27.77	$12.00
	5	$24.72	$11.83
	6	$30.51	$13.47
	7	$228.89	$10.19
	8	$39.68	$9.83
	9	$18.55	$11.04
	10	$19.96	$12.90
	11	$21.43	$15.64
	12	$23.30	$16.07
2000	1	$28.75	$15.77
	2	$24.98	$15.94
	3	$27.36	$14.73
	4	$29.39	$13.84
	5	$40.17	$13.95
	6	$35.54	$14.64
	7	$50.80	$13.42
	8	$62.43	$13.63
	9	$28.71	$15.05
	10	$39.07	$31.01
	11	$45.81	$18.41
	12	$91.32	$18.44
2001	1	$50.61	$21.38
	2	$42.63	$22.13
	3	$44.48	$14.41
	4	$52.17	$12.45
	5	$37.66	$18.11
	6	$39.18	$18.01
	7	$47.51	$12.66
	8	$48.60	$13.77
	9	$22.34	$13.73
	10	$23.39	$14.66
	11	$23.75	$14.98
	12	$22.57	$15.11

Source: Bloomberg

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Late Filed Exhibit No. 17

Requested Information:

Provide details of the changes in Account 921 from 2000 to 2001.

Responses:

Please see Attachment A for the details and a comparison of amounts in Account 921 for 2000 and 2001.

70 PU-399-01-186 Pages: 2

Details on changes in Account 921 from 2000 to 2001
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # Late Filed 17
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Case No. PU-399-01-186
Late Filed Exhibit No. 17
Attachment A

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF OFFICE SUPPLY EXPENSES
ELECTRIC UTILITY
2001

		Acct. 921			
		2001	2000	Change	% Change
5211	Subcontract labor	$533,665	$146,513	$387,152	264.24%
5292	Custodial Services & Supplies	58,407	71,284	(12,877)	-18.06%
5300	Materials	1,882	1,343	539	40.15%
5410	Company Vehicles	15,021	11,068	3,953	35.72%
5511	Commercial Air Service	79,364	93,110	(13,746)	-14.76%
5512	Corporate Aircraft	101,762	23,093	78,669	340.66%
5513	Corporate Aircraft - Undistributed		23,988	(23,988)	-100.00%
5514	Personal Vehicle use	5,879	5,922	(43)	-0.73%
5521	Meals & Entertainment	43,706	45,567	(1,861)	-4.08%
5522	Other Reimbursable Exp.	107,664	105,602	2,062	1.95%
5610	Telephone	369,690	280,403	89,287	31.84%
5620	Photocopier	149,694	123,487	26,207	21.22%
5630	Office Supplies	535,359	376,562	158,797	42.17%
5640	Utilities	6,470	7,201	(731)	-10.15%
5641	Company Consumption - Elec	96,458	109,765	(13,307)	-12.12%
5642	Company Consumption - Gas	48,732	18,108	30,624	169.12%
5651	Postage	110,057	85,559	24,498	28.63%
5652	Express Mail	34,915	25,075	9,840	39.24%
5661	Rental of Office Eqpt.	4,483	4,290	193	4.51%
5811	Professional Organ. Dues	8,478	11,227	(2,749)	-24.49%
5830	Employee Meetings	32,877	42,551	(9,674)	-22.73%
5851	Seminars & Meeting Exp.	40,445	48,993	(8,548)	-17.45%
5852	Executive Training	12,331	11,176	1,155	10.34%
5854	Other Employee Training	47,749	49,538	(1,789)	-3.61%
5911	Software Maintenance	235,325	246,787	(11,462)	-4.64%
5913	Permits & Filing Fees	5,284	3,126	2,158	69.04%
5914	Bank Service Fees	100,007	7,736	92,271	1192.74%
5934	Computer Rental	79,433	99,408	(19,975)	-20.09%
5950	Freight	740	318	422	132.61%
5982	Reference Material	40,154	43,044	(2,890)	-6.71%
5997	Credit Card Approval	0		0	#DIV/0!
	Total	$2,906,032	$2,121,844	$784,188	

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Late Filed Exhibit No. 18

Requested Information:

Update Exhibit No.___ (DRB-2) to include insurance premium expense for 2001.

Responses:

Please see Attachment A.

69 PU-399-01-186 Pages: 2

Details on Update Exhibit No. (DRB-2) to include insurance premium expense
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # Late Filed 18
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF INSURANCE EXPENSE
ELECTRIC UTILITY
2001 AND PROJECTED 2002

Type of Insurance	Company	2001 Expense	2002 Annual Premium	Change	% Change
Director's & Officer's Liability Insurance -- 1st Layer	Federal Insurance Company (CHUBB Group)-Aon Risk Se	$41,386	$38,463	($2,923)	-7.06%
Director's & Officer's Liability Insurance -- 2nd Layer	AEGIS - Aon Risk Services	1,928	1,816	(112)	-5.81%
Director's & Officer's Liability Insurance -- 3rd Layer	Energy Insurance Mutual - Aon Risk Services	28,035	30,089	2,054	7.33%
Director's & Officer's Liability Insurance -- 4th Layer	Clarendon	4,603	10,403	5,800	126.00%
Fiduciary and Employee Benefits Liability Insurance	Johnson & Higgins	8,662	7,873	(789)	-9.11
Public Liability&Property Insurance Damage of Other:	AEGIS - J & H Marsh & McLennan	130,217	187,495	57,278	43.99%
Public Liability&Property Insurance Damage of Other:	Energy Insurance Mutual	7,148	9,192	2,044	28.60%
Fire, Extended Coverage Perils, Boiler & Machinery	FM Global	224,945	311,157	86,212	38.33%
Blanket Crime	Aon Risk Services	3,129	2,635	(494)	-15.79%
Special Contingency	Alexander & Alexander	547	850	303	55.39%
Hired and Non-owned Aircraft Liability	J&H Marsh & McLennan, Inc.	1,570	1,570	0	0.00%
General Liability	Self Insurance	65,700	146,545	80,845	123.05%
Big Stone		53,842	59,280	5,438	10.10%
Coyote		78,775	83,662	4,887	6.20%
Total		$650,487	$891,030	$240,543	36.98%
ND Factor - O&M Excl. Fuel, Purch. Pwr & A&G		64.5967%	64.5967%		
2001 North Dakota Insurance Expense		$420,193	$575,576	$155,383	36.98%

Case No. PU-399-01-186
Late Filed Exhibit No. 18
Attachment A

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Late Filed Exhibit No. 19

Requested Information:

1. Provide the percentage of fixed costs of the aircraft acquired in January 2001 that are charged to Montana-Dakota.

2. Provide the percentage of use of the aircraft for Montana-Dakota that occurred in 2001.

Responses:

1. In 2001, 33.5% of the fixed costs of the aircraft were allocated to Montana-Dakota.

2. In 2001, Montana-Dakota used the aircraft for 36.1% of the trips made.

68 PU-399-01-186 Pages: 1

Details of fixed costs of aircraft

by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # Late Filed 19
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Late Filed Exhibit No. 20

Requested Information:

3. Provide details of the approximate 20% change in Account 920 between 2000 and 2001.

4. Provide the dates and amounts of salary changes.

Responses:

3. Please see Attachment A for the details and a comparison of amounts in Account 920 for 2000 and 2001.

4. The effective dates of increases for non-union and union employees is January 1 and May 1 respectively. The overall percentage increase for 2000 was 3.75% and the overall percentage increase in 2001 was 4.32%.

67 PU-399-01-186 Pages: 2

Details of the change in Account 920/salary changes
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # Late Filed 20
03/05/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Case No. PU-399-01-186
Late Filed Exhibit No. 20
Attachment A

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF A&G SALARIES
ELECTRIC UTILITY
2001

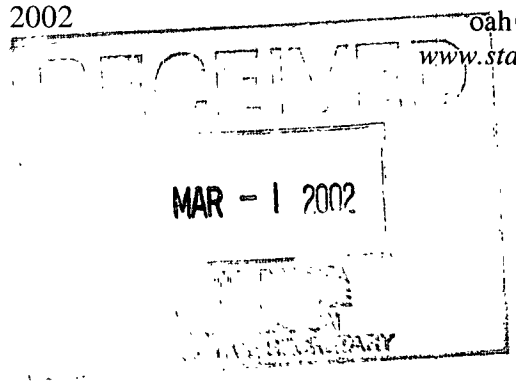
		Account 920			
		2001	2000	Change	% Change
5110	Straight Time	$3,411,907	$3,127,054	$284,853	9.11%
5120	Premium	25,743	27,179	(1,436)	-5.28%
5130	Bonus & commission	1,217,274	581,509	635,765	109.33%
5140	Moving	5,715	226	5,489	2428.76%
5150	Meals	624	551	73	13.25%
5193	Vacation	362,936	444,800	(81,864)	-18.40%
	Total	$5,024,199	$4,181,319	$842,880	20.16%

OFFICE OF ADMINISTRATIVE HEARINGS
STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.state.nd.us/oah

February 28, 2002



Mr. William Binek
Hearing Administrator
Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

Dear Mr. Binek:

On November 27, 2001, you requested the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Montana-Dakota Utilities Co. 2000 Electric Operations Annual Report (PU-399-01-0186). I was designated as a procedural administrative law judge to conduct the hearing, but not to make recommended findings of fact and conclusions of law, or issue a recommended order. The hearing on this matter was scheduled for February 25 and 26, 2002, and was held on those two days. The hearing was closed and the matter submitted to the Commission for final disposition. I understand that the Commission will issue the appropriate order, if necessary.

I am closing our file on this matter and returning that portion of the record I have in my possession to you for filing with the official agency record of this matter, as appropriate. I have returned to you copies of materials submitted to me prior to the hearing. I am also providing you with a copy of the exhibit list I have prepared to help the Commission understand the filing of exhibits. Please file these documents and copies of documents with the file on this matter, as appropriate.

Thank you for your attention to these matters.

Sincerely,

Allen C. Hoberg
Administrative Law Judge

ACH/ljc
Enc.
cc: Douglas W. Schultz
William P. Pearce

66 **PU-399-01-186** Pages: 1

Letter closing ALJ's file

by Office of Administrative Hearings

03/01/2002 CC: Comm Legal PUD (3) Mike ALJ

EXHIBIT LIST

Matter	Montana-Dakota Utilities Complaint - Electric Rates Investigation North Dakota Public Service Commission S="Staff" offered exhibit; M="MDU" offered exhibit; C="Commission" requested; A="Admitted"; NA="Not Admitted"
Hearing	February 25 and 26, 2002 - Public Service Commission hearing room

No.	Description	Mkd	Idd	Ofd	W/D	Adm	Note
1	Mike Diller Direct Testimony (docket #15)			S		A	
2	Mike Diller Rebuttal Testimony (docket #54)			S		A	
3	Mike Diller hollow point presentation on MDU's Operations			S		A	New exhibit, not previously docketed
4	Charles King Direct Testimony (docket #14)			S		A	Minor corrections to exhibit in testimony
5	Charles King Rebuttal (docket #53)			S		A	
6	All of MDU's prefiled Direct Testimony			M		A	See docket index for various docket numbers of all direct testimony witnesses
7	All of MDU's prefiled Surrebuttal Testimony			M		A	Some corrections as noted in testimony (see docket index for various docket numbers of all surrebuttal witnesses)
8	Gaske Surrebuttal - schedule omitted in prefiled materials			M		A	New exhibit not previously docketed
9	Shiffman Surrebuttal - chart (RJS-7) omitted in prefiled materials			M		A	New exhibit not previously docketed

Exhibit List from Feb, 25 & 26, 2002 Hearing
by Office of Administrative Hearings

03/01/2002 CC: Comm Legal PUD (3) Mike ALJ

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

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

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FEB 19 2002
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

February 19, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-01-186

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of the surrebuttal testimony and exhibits of its witnesses in the above referenced case.

Attached is the testimony of Mr. J. Stephen Gaske, Mr. Douglass A. Mahowald, Mr. Paul L. Wilkinson, Mr. Roger Schiffman, Mr. Terry L. Blinsky, Mr. Richard A. Espeland, Mr. Donald R. Ball and Ms. Rita A. Mulkern.

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

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Attachments
c: D. Schulz
W. Pearce

EXHIBIT
7
2/25/02

64 PU-399-01-186 Pages: 1
Cover Letter re Surrebuttal Testimony
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
02/19/2002 CC. Comm Legal Illona, Pat, Jerry Mike

10	Blinsky Surrebuttal - chart (TLB-7) omitted in prefiled materials			M		A	New exhibit not previously docketed
11	Reliability Assessments 2001-2010 (MAPP report) from internet			C		A	Offered by Commissioner Wefald
12	Charles King exhibit - 2001 selected Gas Utility Companies			S		A	New exhibit not previously docketed
13	2000 Update MAPP report			M		A	New exhibit not previously docketed
14	PUR advance sheets (12/15/01)			S		A	New exhibit not previously docketed
15	RJS-8 schedules			M		A	New exhibit not previously docketed
16	RJS-12 (responses to Binek's questions)			M		A	Late-filed exhibit - to be filed in response to Staff questions
17	Office Supplies schedule			M		A	Late-filed exhibit - to be filed in response to Staff or Commission questions
18	Industrial expense schedule (DRB-2)			M		A	Late-filed exhibit - to be filed in response to Staff or Commission questions
19	Airplane Costs schedule (3 items)			M		A	Late-filed exhibit - to be filed in response to Staff or Commission questions
20	Account #920 - Administrative Salaries information			M		A	Late-filed exhibit - to be filed in response to Staff or Commission questions

Exhibit No.___(JSG-3)

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

DOCKET NO. PU-399-01-186

PREPARED SURREBUTTAL TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7720 Wisconsin Avenue, Suite B-102 Bethesda, MD 20814.

Q2. Are you the same J. Stephen Gaske who filed Prepared Direct Testimony earlier in this proceeding?

A. Yes.

Q3. What is the purpose of your Prepared Surrebuttal Testimony?

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to evaluate the Rebuttal Testimony of Charles W. King filed on behalf of the Staff of the North Dakota Public Service Commission ("PSC") on February 11, 2002. In his rebuttal testimony, Mr. King makes a number of errors in analysis that lead him to recommend an inadequate allowed rate of return for setting Montana-Dakota's North Dakota electric rates. Consequently, I will respond to various issues addressed in Mr. King's rebuttal testimony including: the cost of debt, the need for a flotation cost adjustment, the dividend yield adjustment to the DCF model, the relevance of the Risk Premium and Alternative Equity Investment analyses in my

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Surrebuttal Testimony of J. Stephen Gaske
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
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Prepared Direct testimony, the selection of a proxy group, and the risk implications of being a diversified, regulated company.

In addition, I have been asked to comment on some of the economic assumptions that PSC Staff witness Mike Diller has relied upon in attempting to establish a test-year amount of margins from sales for resale to be credited to North Dakota ratepayers.

Debt Cost

Q4. Do you have any comments on Mr. King's recommended cost of debt for Montana-Dakota?

A. Yes. In his rebuttal testimony, Mr. King concedes that he had incorrectly calculated the cost of debt for Montana-Dakota in his direct testimony. Nevertheless, he recommends that the PSC adopt his admittedly incorrect debt cost because his incorrect number is lower than the correct number. Mr. King's rationale for recommending use of an incorrect number is that the cost of Montana-Dakota's debt currently is higher than the cost of debt experienced by some other utilities in North Dakota. By recommending that the PSC effectively disallow a portion of Montana-Dakota's debt cost, the implication is that Montana-Dakota has been imprudent in managing its cost of debt. However, Mr. King does not present any evidence that the Montana-Dakota debt cost is excessive, unreasonable or imprudent.

Q5. Is it normal for different utilities to have different costs of debt?

A. Yes. The cost of debt in the capital markets fluctuates over time. As companies need to issue new debt to finance new plant, or repay existing debt as it comes due, or for other purposes, they go to the capital markets and must pay the competitive cost that is available in the market at that time. If all utilities in North Dakota were to issue all of their debt at the same time, they might have debt costs that are nearly identical. However, all utilities in North Dakota do not have the same simultaneous needs to issue debt. Thus, differences in debt costs are often explained by the vintage of the debt obligations of different utilities.

Q6. How does the vintage of its debt affect Montana-Dakota's debt costs?

A. Because the cost of long-term debt has declined considerably during the past 15-20 years, the timing of Montana-Dakota's debt issuances explains nearly all of the differences between Montana-Dakota and the other two North Dakota comparison utilities referenced by Mr. King. For example, Montana-Dakota's long-term debt issued after April 1992 has an average cost of 7.31 percent. This is lower than the 7.68 percent debt costs of Otter Tail Power Company that Mr. King cites in his rebuttal testimony and very close to Northern States Power Company's 6.99 percent long-term debt costs that he cites.

The primary reason that Montana-Dakota has higher debt costs than these other North Dakota companies is the cost associated with debt refinancing in April 1992. As described in the Prepared Surrebuttal Testimony of Mr. Mahowald, in order to obtain lower debt costs, Montana-Dakota refinanced a large amount of debt

at that time. The costs, as well as the benefits, of this refinancing are still a part of Montana-Dakota's cost of debt.

Q7. Are there other reasons for the magnitude of the differences between Montana-Dakota and the other utilities?

A. Another reason that Montana-Dakota appears to have higher debt costs than the other two North Dakota companies may be attributable to differences in the methods used to calculate Montana-Dakota's debt costs and the debt costs of the other two utilities. In response to a data request, Mr. King provided a copy of the calculation of the 6.99 percent debt cost for Northern States Power Company ("NSP"). This calculation shows that the debt costs were calculated using the same accounting-based approach that Mr. King advocates in this proceeding. As I discussed in my Prepared Direct Testimony, and as Mr. King concedes, this accounting-based calculation understates the effective cost of debt and is contrary to the usual method of calculating effective debt costs for ratemaking, which uses a "yield-to-maturity" calculation. If the effective NSP debt costs were to be calculated using the "yield-to-maturity" approach that is appropriate for ratemaking, the cost of NSP's debt for ratemaking purposes undoubtedly would be higher than the "accounting-based" cost. Mr. King also indicated in his data response that he did not know the details of how the Otter Tail debt cost was calculated.

Q8. What do you conclude with regard to Mr. King's debt cost recommendation?

A. Although Mr. King concludes that Montana-Dakota has "... what *appears to be* an unreasonably high debt cost,"[1] his analysis did not attempt to determine the

[1] Rebuttal Testimony of Charles W. King, page 2, lines 25-26, emphasis added.

reason for the difference between Montana-Dakota's debt costs and the costs of the other two North Dakota utilities. Even the most cursory inquiry into the reasons for Montana-Dakota's higher debt costs would have shown that these costs are reasonable.

Flotation Cost

Q9. At page 4, lines 1-5 of his testimony, Mr. King claims that Montana-Dakota's costs of raising new common equity capital are 0.94 percent. Do you agree with his analysis and conclusion?

A. No. Mr. King has made a classic "apples-to-oranges" comparison in attempting to calculate the flotation costs that Montana-Dakota would incur if it needed to attract any significant amount of new common equity capital in order to finance its electric utility operations. Mr. King's analysis looks at the issuance costs that Montana-Dakota has incurred since 1997 to conclude that the cost of *issuing* new common equity are relatively low. However, the real test of a reasonable allowed return is whether it is sufficient to attract new capital for investment in the regulated operation on reasonable terms. Mr. King's analysis does not address that issue.

Q10. What aspects of Mr. King's analysis on Exhibit ___(CWK-1R) are off-point?

A. Mr. King's analysis shows the costs associated with issuing new shares of common stock, however, the majority of the "amount raised" consisted of non-cash acquisitions of stock in other companies. In other words, "amount raised" is a misnomer when applied to the acquisition issuances because no new funds were raised when this stock was issued. Instead, MDU Resources acquired other

companies by trading new shares of its stock for the stock of those companies. As Mr. King shows, the cost of *exchanging* MDU shares for shares in a company being acquired are quite low. No additional capital was raised in these transactions and there were no cash funds raised that could be used to maintain or construct utility plant. Consequently, costs associated with issuing new stock as part of acquisitions have no bearing on the costs that Montana-Dakota or MDU Resources would incur if it needed to attract capital to fund cash investment in its utility operations.

MDU also issues new shares through its dividend reinvestment plan ("DRIP"), and its employee 401K and Stock Option plans. However, none of these plans has been a significant source of capital for the company in recent years. For example, no shares have been issued through the DRIP or 401K plans since March 1999. Thus, the cost of issuing these shares tells us little or nothing about MDU's cost of attracting capital funds for investment in its electric utility rate base.

Q11. Which of the types of stock issuances shown on Exhibit ___(CWK-1R) are relevant for estimating Montana-Dakota's cost of attracting common equity capital for investment in its electric operations?

A. The most relevant type of issuance is shown on line 4 of Exhibit ___(CWK-1R) and is labeled as "Equity Draw Down." This line indicates the flotation costs that MDU Resources has incurred in the recent past in connection with approximately 90 percent of the new common equity capital amounts raised through stock issuances that were available for investment in rate base since 1997. In fact, during the past three years, the "Equity Draw Down" category has accounted for more than 95 percent of the new common equity capital issued to raise funds that

could be invested in rate base. The flotation cost associated with obtaining this capital was 3.43 percent, computed as follows:

Amount Raised	$157,411,736
Flotation Cost	5,214,211
Net Funds Available	$152,197,525
Flotation Cost/Net Funds	3.43%

Thus, if one focuses on the portion of Mr. King's analysis that is relevant for estimating Montana-Dakota's cost of attracting new common equity capital for investment in its electric utility operations, that past experience indicates a cost of 3.43 percent. Since the recent past experience of MDU Resources is close to the cost experienced by other electric companies on some stock issuances, as shown on Exhibit No. ___(JSG-2), Schedule 5, it is clear that the flotation cost adjustment should be at least 3.43 percent. However, the experience of other electric companies suggests that a flotation cost adjustment of 4.75 percent is required to ensure that the allowed rate of return is sufficient to attract capital on reasonable terms.

Q12. Mr. King also objects to the fact that you have applied the flotation cost adjustment to the entire equity amount. Why is this treatment appropriate for setting the allowed rate of return?

A. As I explained in my Prepared Direct Testimony, a healthy company should be in a position to issue common stock on reasonable terms at all times. This requires that the entire investor return requirement be increased so that the stock price is sufficiently above book value that stock can be issued without diluting the value of existing shareholders' investments. Flotation costs are a necessary component of the cost of attracting capital. Thus, without a flotation cost adjustment, the return would be insufficient to "assure confidence in the

financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Q13. Is the need for a flotation cost adjustment to the entire return widely recognized among economists as a required part of an allowed rate of return that will attract capital without diluting the value of existing investors' equity?

A. Yes. In commenting on the fair rate of return in his classic treatise on public utility ratemaking, Bonbright stated that:

> *"...book values (with allowances for the probable need to underprice new common-stock offering) should set a floor to the market values..."*

James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with having developed the DCF model for estimating rate of return, has stated that a regulatory agency should set the allowed rate of return greater than the investor return requirement so as to allow the firm to issue stock at a price that will yield net proceeds equal to book value. Professor Gordon advocates the following adjustment:

> *"The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value."*

Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166. In order to meet this requirement, the flotation cost adjustment must be applied to the entire rate of return. The flotation cost

adjustment that I have proposed attempts to meet the same standards advocated by these other economists.

Q14. Mr. King suggests at pages 4-5 that because MDU Resources common stock is selling at a premium to book value, no flotation cost adjustment is required. Do you agree with this assessment?

A. No. MDU Resources is a diversified company with significant unregulated operations. There is no evidence whatsoever that the North Dakota electric operations contribute to the fact that MDU Resources' common stock is selling at a premium over book value. In fact, at a market-to-book ratio of 1.78 MDU Resources' stock premium, 0.78, is less than one-sixth of the 5.23 average premium for industrial companies.[2] The fact that MDU Resources has such an exceptionally low premium may be attributable to the relatively lower value of its regulated operations. With such a low premium for MDU, it is reasonable to expect that the market value of the North Dakota electric utility operations is close to, or possibly even less than, book value in order to offset the probable market-to-book ratios of MDU Resources' other unregulated operations.

At page 5, lines 2-3, Mr. King asserts that "(a)ny sales of new MDU's stock would cause book value appreciation, not dilution." This observation is correct, but irrelevant for setting an allowed rate of return in this proceeding. Although the book value can increase when new shares are issued, the effect on the *market* value of the stock is far more relevant. If MDU Resources invests the newly-raised equity funds in a regulated operation that has a market value equal

[2] The average market-to-book ratio for the S&P Industrial Index is 6.23 according to *Barron's*, February 11, 2002, page MW 46.

to book value, it drives down the market value of existing investors' stock by an amount equal to the flotation costs. Thus, in the absence of a flotation cost adjustment to the investor-required return, Mr. King's recommendation would be relying on MDU Resources' investors to cross-subsidize the North Dakota electric operations by forfeiting a portion of the value of their unregulated operations if there is a need to issue stock to finance the North Dakota electric operations.

Selection of Combination Companies as Electric Proxies

Q15. At page 5, lines 20-25 of his Rebuttal Testimony, Mr. King asserts that the fact that two groups of companies do not have statistically significant difference in the averages of their DCF results "does not mean that the risks are not different ... and the required returns are not higher." Is this observation germane to the point that you made in your Direct Testimony?

A. No. In his Direct Testimony at page 23, lines 1-9 Mr. King asserted that the difference in risk between electric companies and combination companies is shown by the fact that his combination company group has a lower average DCF result than his electric company group. Because Mr. King suggested that the difference in DCF results implies a lower risk and return requirement for combination companies, I performed a statistical test of Mr. King's proffered evidence. This test indicated that Mr. King could not assert that a difference in the average returns necessarily implies a difference in risk as between the two groups. I would agree with Mr. King that the DCF results for the two groups does not mean that the risks are not different. However, as my Direct Testimony demonstrated it also would be wrong to suggest that the DCF results mean that the

risks are different. The point is that no risk conclusions can be drawn from the DCF results.

Q16. Even if there are other reasons for believing that combination companies have different risks than electric companies, would Mr. King be correct in throwing out the results for electric companies and replacing these with results for combination companies?

A. No. As I discuss at pages 23-25 of my Prepared Direct Testimony, the purpose of this proceeding is to set rates for electric operations. Consequently, it is most appropriate to use a proxy group of companies that have a high percentage of their business in electric operations. It may be true that a diversified company, such as a combination company or a conglomerate, poses less risk to stockholders than any of its subsidiaries individually, but that does not mean that those individual operations have a lower risk or cost of capital by virtue of being part of a diversified combination company or conglomerate. Indeed, Mr. King indicated at page 13, lines 15-17 that his purpose was to determine a rate of return for equity capital investment in Montana-Dakota's North Dakota electric operations. However, in the conduct of his study he abandoned that goal and replaced it with the goal of setting a rate of return for a combination company.

Q17. Is Mr. King's intuitive reason for using combination companies in place of electric companies correct?

A. No. His reasoning is incorrect for two reasons.

First, as a general matter, ownership of natural gas distribution operations does not reduce the risk of investing in electric utility operations as Mr. King

claims. For example, if Montana-Dakota invests $50 million in a new electric generating plant and its customers decide that they do not want to use electricity but, instead, prefer to use natural gas, Montana-Dakota's investment in electric plant would become worthless. This is true regardless of who owns the local natural gas distribution company. If the customers all switch to natural gas for all of their energy needs, Montana-Dakota would then need to go out and invest additional funds in its natural gas operations to accommodate the increase in demand for natural gas and, under regulated ratemaking, it should get additional revenues associated with that increased investment in natural gas plant. However, that increased investment and revenue on the gas side would not change the fact that the electric plant is rendered worthless. Consequently, the decision to invest in electric plant depends solely upon the risk of the electric operations.

Q18. Could there be circumstances under which Mr. King's theory, stated at page 23, lines 5-9 of his Direct Testimony, is correct that a combination company has lower risks associated with investing in electric plant because "... when it offers both gas and electricity, it has a reasonable guarantee that regardless of changes in heating technology or consumer preference, it will control most of the market for heating fuel?"

A. Yes. Investors are not so much concerned with the total share of the fuels market that a company "controls" as they are concerned about whether they will recover the costs of their investments plus a reasonable return on those investments. It is the risk associated with cost recovery that concerns investors when they commit capital to an operation. This risk could be reduced in a

combination company if, for example, the North Dakota PSC were to adopt a policy that Montana-Dakota's electric utility costs will be recovered in an adder to its rates for natural gas distribution service any time Montana-Dakota loses electric business to its natural gas distribution operation. In that unlikely circumstance, any revenue and cost recovery that cannot be obtained from electric operations would be recovered from natural gas customers and Mr. King's theory would be correct that risks of recovering costs invested in electric plant are relatively unaffected "regardless of changes in heating technology or consumer preference."

Q19. Has the North Dakota PSC guaranteed that any stranded electric investments can be recovered from gas distribution customers?

A. No, and it is unlikely that the PSC has the statutory authority to include electric costs in gas rates. For that reason, Mr. King's reasoning is simply incorrect. The risk of investing capital in electric operations is not reduced by virtue of being a combination company and the correct proxy group for setting electric rates would include electric companies, even if they do not also own gas distribution operations.

Q20. What is the other reason that Mr. King is wrong about the effect of being a combination company on the Montana-Dakota's risk of electric operations?

A. He has provided an incomplete analysis of the gas and electric operations of Montana-Dakota. For example, at page 6, lines 19-24, he cites the fact that some of Montana-Dakota's North Dakota customers use electricity for space

heating and water heating. However, a large portion of those customers are located in areas where natural gas is not available.

Selection of Electric Companies as Electric Proxies

Q21. Mr. King objects to the use of three companies in your proxy group that derive more than 75 percent, but less than 85 percent, of their revenues from electric operations. Do you agree with his reasons for attempting to exclude such companies from the proxy group?

A. No. On page 7, line 19 to page 8, line 4 Mr. King indicates that he objects to including these companies in the proxy group primarily because they have required returns that are above average. At page 8, lines 7-9 Mr. King also says that these three companies should be excluded because:

> "In each case, the driving factor in investors' assessments of these companies is either their ***wholesale electric operations, which are effectively unregulated,*** or their non-utility operations." (Emphasis added.)

However, as shown below, these three companies derive a greater share of their revenue from electric operations than at least three companies that Mr. King would prefer to include in the proxy group:[3]

Companies Excluded By Mr. King	% Electric Revenue	Companies Included By Mr. King	% Electric Revenue
IDACORP	**82.0**	Consolidated Edison	**73.6**
American Electric Pwr.	**79.1**	Alliant	**68.5**
Cleco Corp.	**75.5**	Energy East	**68.4**

Under the circumstances, it is difficult to understand what principle Mr. King could invoke to exclude the three companies that derive more than 75 percent of

[3] Exhibit No. ___(JSG-2), Schedule 3, Page 1.

their revenue from regulated electric operations and replace them with three companies that derive less revenue from regulated electric operations.

Q22. In your opinion, are companies that derive revenues from wholesale electric operations comparable to Montana-Dakota's electric operations?

A. Yes. The primary impetus for this proceeding was the revenues that Montana-Dakota derived from wholesale electric operations when wholesale electric demand and prices were unusually high. The Staff of the PSC is advocating that expected future wholesale revenues be credited to the retail cost of service for the benefit of North Dakota ratepayers. Consequently, those companies that Mr. King would exclude because they also sell power in wholesale markets are precisely those companies that are most comparable to Montana-Dakota's North Dakota electric operations. In this regard, the *Value Line* summary for IDACORP that Mr. King quotes at page 8 of his Rebuttal testimony is particularly germane. A portion of the summary that Mr. King did not quote states the following:

> *"Earnings probably won't match 2000's record performance. Though wholesale energy sales were strong, they will be less than those of last year. ... Thus, despite a 2% increase in retail sales, we estimate a 7% decline in 2001 earnings, to $3.25 a share.* ***An expected drop in wholesale energy prices indicates a further decline next year.***"[4]

In this respect, IDACORP is very similar in risks to Montana-Dakota. Nevertheless, Mr. King would exclude IDACORP from the proxy group specifically for that reason which makes it most similar in risk to the Montana-Dakota North Dakota electric operations.

[4] *Value Line*, page 1786, November 16, 2001, emphasis added.

Dividend Yield Adjustment Factor

Q23. Is Mr. King correct in his description and assessment of the 0.625g dividend yield adjustment factor that you recommend?

A. No. Mr. King's first error occurs at page 9, lines 7-8 when he says that my 0.625g factor "assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase." This statement is incorrect. Attached as Exhibit ___(JSG-4), Schedule 1 is a copy of the response that was provided to Mr. King's request for the derivation of the 0.625g factor. That response clearly indicates that if one assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase, the correct adjustment factor is **0.75g**. Thus, it is clear that the 0.625g is not based on that assumption.

Mr. King's second error occurs at page 9, lines 8-9 where he says that "(t)he average for the next dividend increase is thus (.25+.50+.75+1.0)/4 = .625." However, as shown on the attached data response this calculation of Mr. King's mis-states the source and derivation of the 0.625g factor. Instead, the 0.625 is the average of two far more complex calculations that incorporate the timing and time value of both dividends and dividend growth. The assumptions and results of these two complex calculations can be summarized as follows:

First Dividend Received In:	Dividend Increase In:	Factor Derived
3 months	6 months	0.75
0 months	6 months	0.50
Average		**0.625**

Thus, the 0.625 factor is the average of the assumption that the first dividend is received in (i) 3 months, and (ii) it is received immediately. The average of these

two assumptions approximates the assumption that the first dividend could be received at any time during the first three months. In addition, both calculations assume that the dividend increase occurs in 6 months, which is consistent with Mr. King's assumption.

Mr. King's third error occurs when he states that his .5g factor reflects the assumption that the dividend increase is randomly distributed throughout the year and that the average delay in the dividend increase under Mr. King's assumption is one-half a year. As shown in the preceding paragraph and the attached data response, Mr. King's 0.5g factor is correct only in the extreme case that the next dividend is to be received immediately upon purchase of the stock, with no delay. However, if one must wait 3 months for the first dividend, the correct factor is 0.75g. The average of these two extremes produces the most reasonable dividend adjustment factor: 0.625g.

Q24. If you and Mr. King both agree that it is most reasonable to assume that the next dividend increase is one-half year away, why is the appropriate dividend adjustment factor 0.625 and not 0.5?

A. Although Mr. King is correct about the assumed timing of the dividend increase, his error occurs when he mistakenly concludes that the timing assumption is identical to value. However, one of the salient features of the DCF model is that it also incorporates the time value of money in order to find the cost of capital that equates the market price of a share of stock with the expected timing and amount of future dividends. For example, if there is a 50% chance that a dividend increase will occur at the beginning of the year and a 50% chance that it will occur at the end of

the year, the average expected timing of the dividend increase would be at mid-year. However, because a dividend increase received at the beginning of the year has a greater discounted present value than a dividend increase received at the end of the year, the effect of a mid-year timing assumption results in a dividend adjustment factor that is greater than one-half.

Significance of Benchmark Analyses

Q25. At pages 9-11, Mr. King criticizes your benchmark analyses. Are his criticisms misplaced?

A. Yes. For example, in discussing my Risk Premium analyses Mr. King sets up a "straw man" by stating that "(t)he theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials." However, that is neither my theory nor the theory that guides how I have used these analyses.

The return required by investors is estimated by my DCF analysis. But it is also true that when investors decide to purchase common stocks, rather than buy a new car or invest in long-term bonds, they are aware of and influenced by the premium that common stocks have historically earned relative to bonds. In fact, if the long-term average premium were zero or negative, it is doubtful that investors would purchase common stocks or make any equity investments at all. Indeed, through the workings of competitive markets equity investments, stock prices and bond yields all interact to force the long-term average premium to be a positive number. On a year-to-year basis, actual results are bound to differ from the long-term average and the expected risk premiums that investors require will vary

significantly. However, the Risk Premium analysis is a good benchmark to determine whether the return generated by my DCF analyses is within a reasonable ballpark relative to historic average risk premiums. The greater the difference between the DCF results, the more one would have to question whether the DCF results are valid. Thus, although I do not believe that the Risk Premium results are equal to the required rate of return, such results still provide an important perspective for evaluating the DCF results.

Q26. Are Mr. King's criticisms of your Alternative Equity Investment analysis similarly misplaced?

A. Yes. I have no doubt that investors in electric utility assets similar to Montana-Dakota's North Dakota operations do not require the 29.4 percent return on average book value that investors in industrial companies have achieved in recent years. However, that is the level of returns that Montana-Dakota must compete against in attracting capital.

An allowed rate of return established by the DCF method should make the value of the electric operations equal to the book value of those operations in the absence of a flotation cost adjustment. In other words, the purpose of the DCF analysis is to find the rate of return that will make investors indifferent between investing to provide electric service to the public or investing in, for example, U.S. Treasury bills. In contrast, when investors or corporations invest in non-regulated assets the market value of those investments has been many times the book value.

Consequently, when managers of a company evaluate possible investments they must consider the possibility of investing $1.00 in electric utility assets with the expectation that the market value of those assets will be $1.00 and, thus, no value will be created for investors. On the other hand, when managers invest $1.00 in non-utility assets, they have a reasonable possibility of earning a 29 percent return on that investment and turning $1.00 of book value into $6.23 of market value.[5] Thus, while Montana-Dakota does not require anything close to a return of 29 percent on its electric investments, knowledge of such average returns that Montana-Dakota must compete against helps place Montana-Dakota's required rate of return of 12.75 percent in perspective.

Factors Affecting Sales for Resale Margins

Q27. What is the difference in the estimates of sales for resale advocated by Mr. Diller for the PSC Staff and the estimates developed by Mr. Blinsky of Montana-Dakota?

A. At page 3 of his Rebuttal Testimony, Mr. Diller advocates use of a sales for resale margin of $13,667,000 based on 2001 actual sales for resale data. In contrast, Montana-Dakota estimates a margin of $7,247,000. The primary difference in their results occurs because Mr. Diller has not adjusted his test-year data for changes that have occurred in the wholesale markets for electricity, whereas Mr. Blinsky has made such adjustments.

[5] The average market-to-book ratio for the S&P Industrial Index is 6.23 according to *Barron's*, February 11, 2002, page MW 46.

Q28. At page 11 of his Rebuttal Testimony, Mr. Diller indicates that the Commission should use actual results and he indicates that adjustments to reflect prices in the futures markets should not be used. Are futures prices an accurate indicator of expected future prices?

A. Yes. Although actual results in the future undoubtedly will vary from the current prices in futures markets, these futures prices provide the best estimate of prices that can be expected in the future.

In fact, prices projected by reference to the futures market can be virtually assured of becoming actual results for a significant portion of the expected sales for resale if a seller currently locks in the futures price by selling a futures contract that commits it to sell electricity in the future at a certain price. Such a sale of a futures contract is referred to as "hedging" when the seller expects that it will actually make such sales at the market-based price that prevails in the future. By selling a futures contract that covers a significant portion of its expected sales for resale output, if actual prices are lower than the price specified in the futures contract, the electricity seller will sell its output at the lower-than-expected price, but will also make a profit on its futures contract. The sum of the actual sales revenue, plus the profit on the futures contract, less the brokerage fees and other expenses associated with the futures contract, should provide an effective actual price very close to the price projected by using the futures market to estimate likely prices. Conversely, if actual market prices turn out to be higher than the price specified in the futures contract, the company will sell its output at the higher-than-expected market price, but lose

money on the futures contract, so that the effective actual price would still be very close to the price projected by the futures market.

In other words, prices in the futures market are a reliable, unbiased estimate of the market prices that will be available in the future and should be used for making test-year adjustments to the sales-for-resale price used to set Montana-Dakota's rates.

Q29. Is MDU likely to replicate the unusually large sales for resale margins that it generated in 2000 and 2001?

A. No. That was a very unusual period of time in the energy markets when several factors converged to create high prices for wholesale electric power. Natural gas prices had temporarily spiked to exceptionally high levels, a drought in the western states had reduced the amount of hydroelectric power available, and the economy was strong and had grown rapidly. All of these factors combined to create very high demand and prices for wholesale electric power. However, these unusual conditions are not likely to be present in the near future.

Q30. Please describe the changes in the overall U.S. economy that have occurred during the past several years.

A. Measures of economic activity can be seen in Exhibit No. ___(JSG-2), Schedule 1, page 1 and Exhibit ___(JSG-4), Schedule 4, pages 2, 3, 5 and 6. After growing rapidly from 1997 to 2000 the U.S. economy entered a recession during the second half of 2001 and continues to be shrinking.

In addition, as shown on page 2 of Schedule 2 of Exhibit ___(JSG-4), manufacturing production increased to very high levels in 2000 and 2001, but it is

projected to be at significantly lower levels in 2002. As discussed in the Direct Testimony of Mr. Blinsky, this rapid growth placed strains on the electric and natural gas infrastructure and contributed to unusually high energy prices in 2000 and 2001. However, the combination of reduced manufacturing production and large amounts of new, efficient electric generation coming on-line has contributed to an expectation of greatly reduced energy prices during the next year.

Q31. How does the price of natural gas affect prices in wholesale electric power markets?

A. As discussed in the testimony of Mr. Schiffman, gas-fired generation competes directly with coal-fired generation in the wholesale electric power markets. When the price of natural gas increases, the cost of gas-fired generation also increases, thereby generally driving up the overall market price of electricity. During the past several years, companies with coal-fired generation, such as Montana-Dakota, have been able to achieve exceptionally high margins on their sales for resale because the price of coal has remained relatively constant while the price of gas temporarily spiked at unusually high levels. In fact Montana-Dakota's costs of coal at several plants actually declined during the past several years.[6]

Q32. How have natural gas prices changed during the past few years?

A. As shown on page 1 of Schedule 2, average natural gas prices increased from approximately $2.50 in the 1998-1999 time frame to approximately $4.40 in the years 2000 and 2001. In other words, average natural gas prices increased approximately 75 percent in the 2000-2001 time period. A number of factors

[6] Testimony of Mike Diller, page 31.

contributed to this large increase in natural gas prices. For example, low water conditions reduced the amount of hydroelectric generation available in 2000 and 2001 and caused an increase in gas-fired generation. This larger than normal use of natural gas during summer months, combined with record cold weather in the east during the Winter of 2000-2001, reduced natural gas storage stocks and increased the effective market price associated with natural gas transportation and also drove up the well-head price of natural gas.

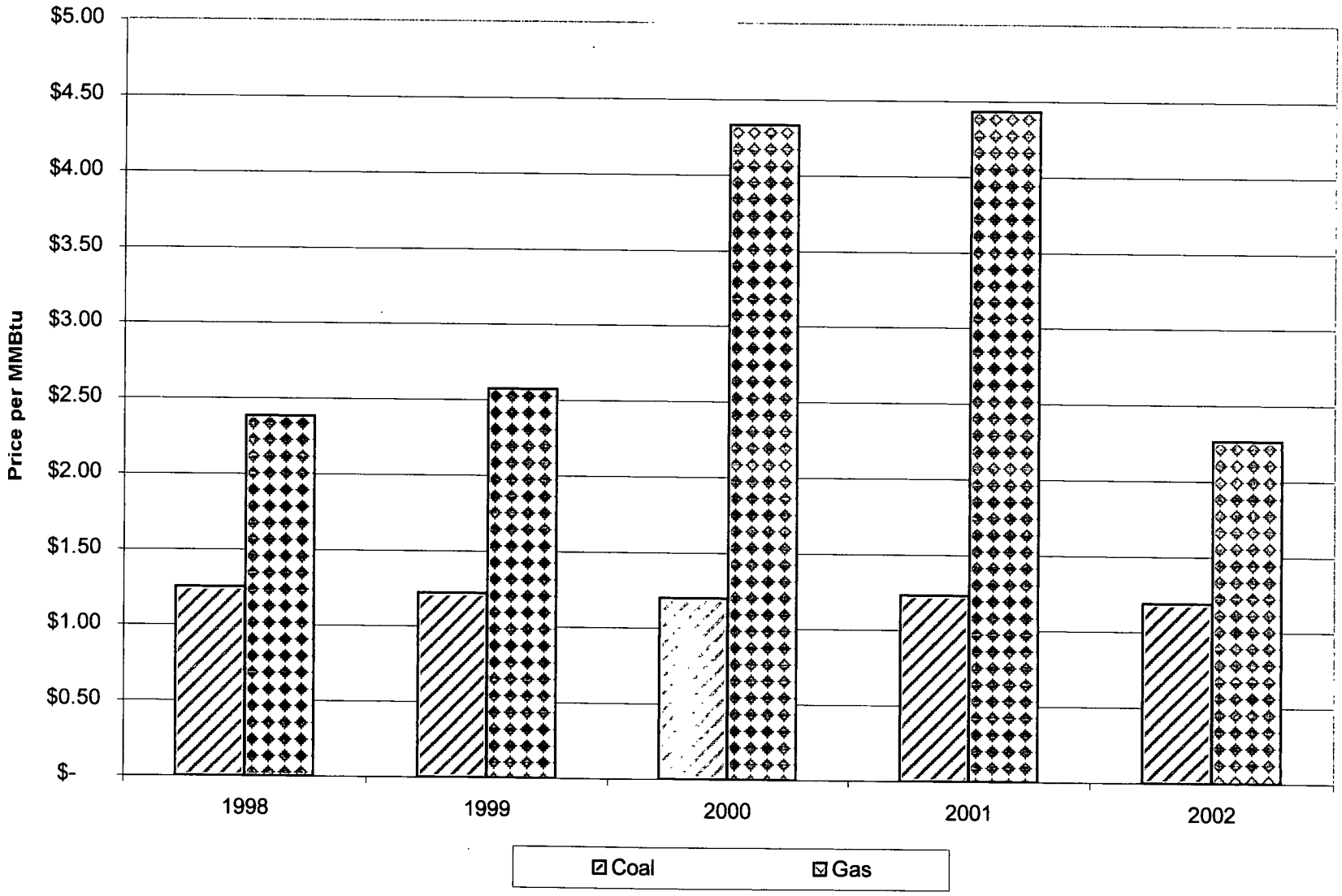
Q33. Are high natural gas prices expected to persist in the future?

A. No. As shown on page 1 of Schedule 2, the average price of natural gas is projected to decrease to approximately $2.25 in 2002. This is lower than the average price of natural gas in any year of the years 1998 to 2001. In fact, it is approximately one-half of the high average prices experienced during the years 2000 and 2001. Consequently, the cost of gas-fired generation in 2002 is projected to be lower than it has been at any time during the past four years and far lower than it was in 2000 and 2001. This greatly reduced gas price, combined with an increased amount of new, efficient gas-fired generation, should cause a significant decline in wholesale electric prices in 2002.

Q34. Does this conclude your Prepared Surrebuttal Testimony?

A. Yes.

Average Annual U.S. Energy Prices
1998-2001 Actual - 2002 Projected



Source: U.S. Dept. of Energy, Energy Information Administration, *Short-Term Energy Outlook*, February 2002.

Exhibit No.___(JSG-4)
Schedule 2
Page 1 of 6

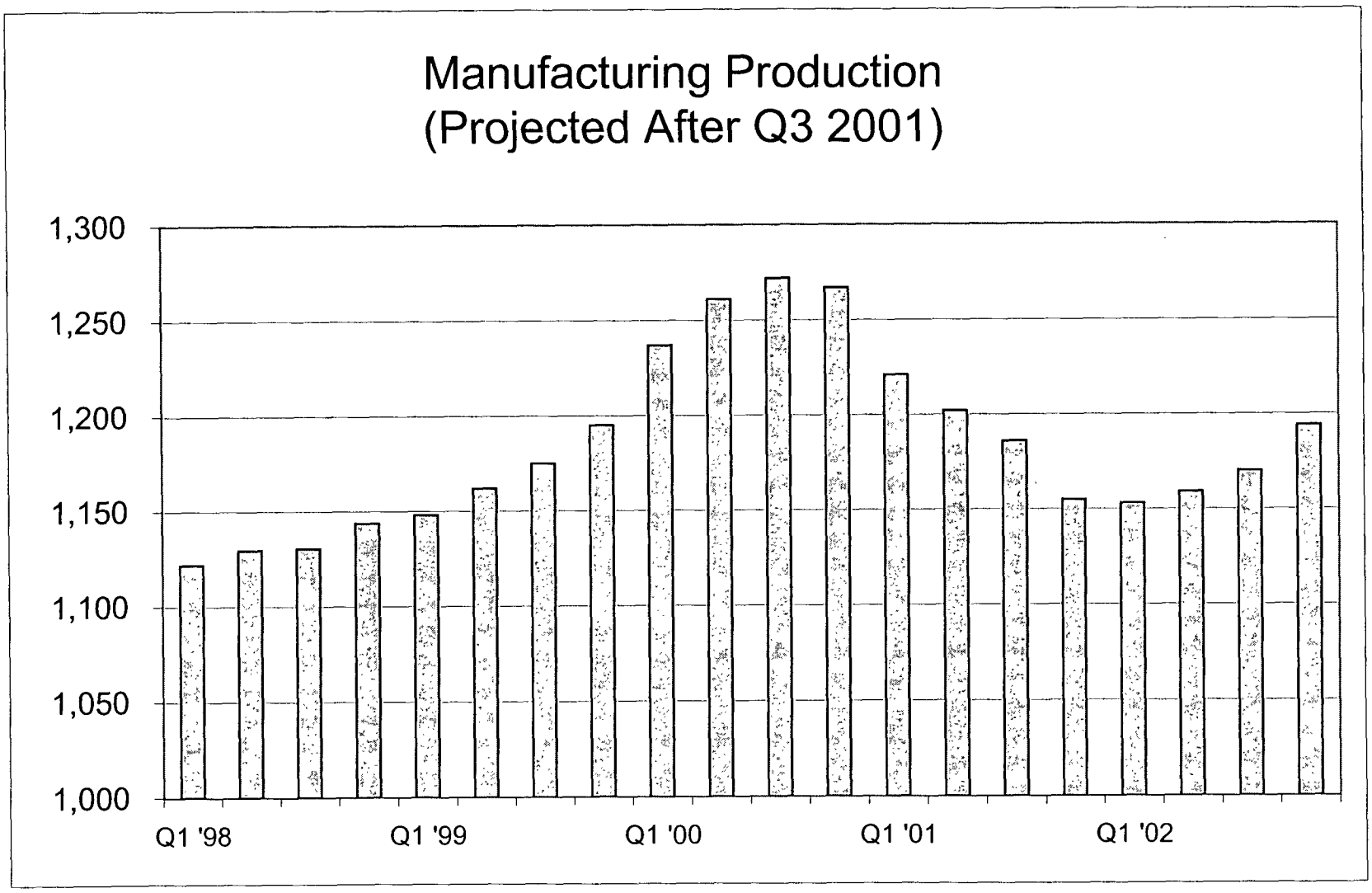


Exhibit No.____(JSG-4)
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U.S. Macroeconomic Factors
% Change

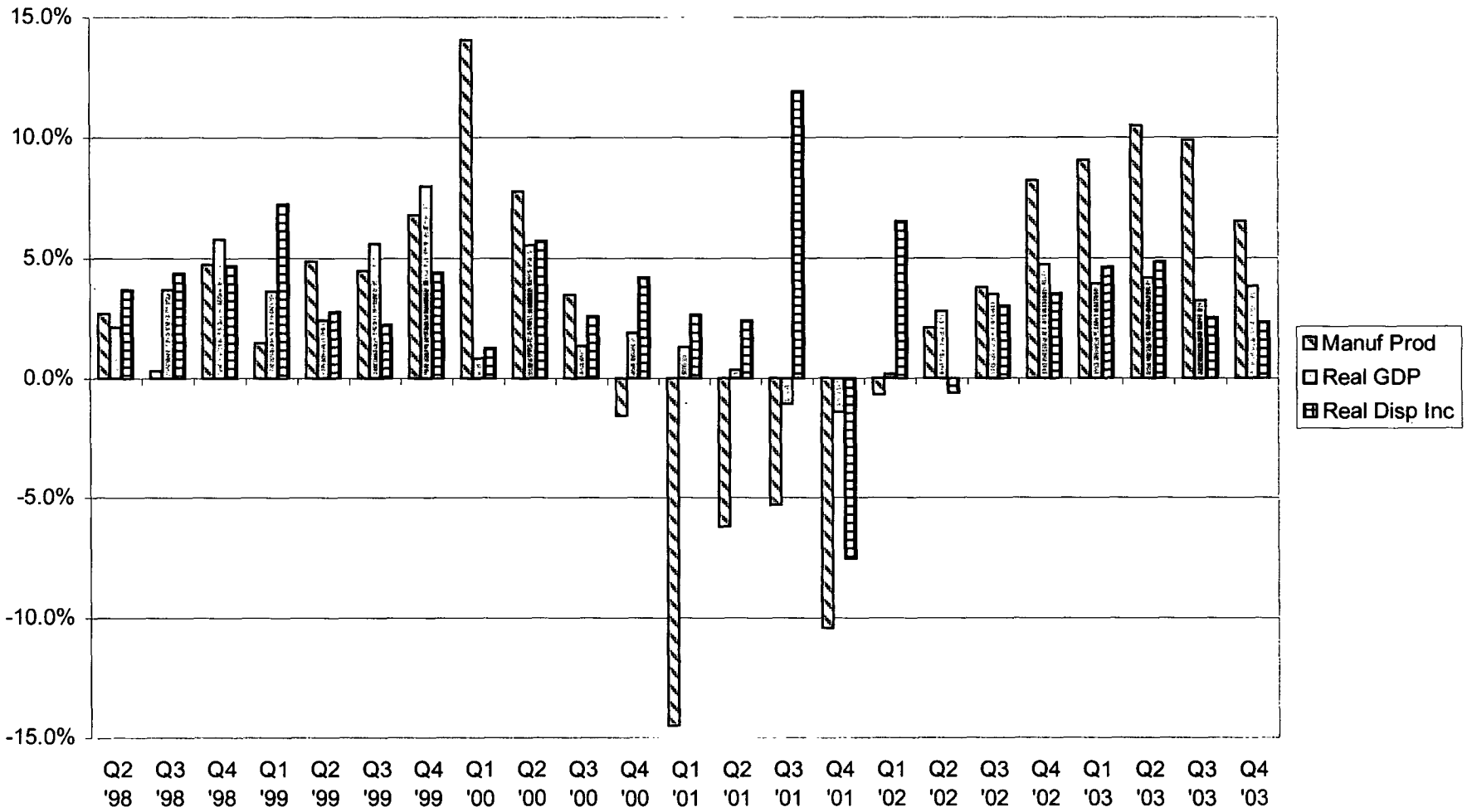

Exhibit No.___(JSG-4)
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Annual Average U.S. Energy Prices
Cost per MMBtu

Line No.	Description	Year 1998	1999	2000	2001 Estimated	2002 Estimated	2003 Estimated
	Electric Utility Fuels						
1	Coal	$ 1.25	$ 1.22	$ 1.20	$ 1.23	$ 1.19	$ 1.18
2	Natural Gas	$ 2.38	$ 2.57	$ 4.33	$ 4.43	$ 2.26	$ 2.86

Source: Energy Information Administration/Short-Term Energy Outlook- February 2002. Table A4

Exhibit No.____(JSG-4)
Schedule 2
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Quarterly Data on the Economy

Line No.	Description	1998 1st Qtr.	1998 2nd Qtr.	1998 3rd Qtr.	1998 4th Qtr.	1999 1st Qtr.	1999 2nd Qtr.	1999 3rd Qtr.	1999 4th Qtr.	2000 1st Qtr.	2000 2nd Qtr.	2000 3rd Qtr.	2000 4th Qtr.
1	Real GDP *	8,405	8,450	8,528	8,652	8,730	8,783	8,906	9,084	9,103	9,229	9,260	9,304
2	Manuf Production **	1,122	1,130	1,130	1,144	1,148	1,162	1,175	1,195	1,237	1,261	1,272	1,267
3	Real Disposable Personal Income ***	5,960	6,015	6,081	6,153	6,264	6,307	6,342	6,412	6,432	6,524	6,566	6,635
	Percentage Change From Previous Qtr.												
4	Real GDP		0.92%	1.10%	1.17%	1.81%	0.69%	0.55%	1.10%	0.31%	1.43%	0.64%	1.05%
5	Manuf Production		0.67%	0.07%	1.19%	0.37%	1.22%	1.12%	1.70%	3.51%	1.94%	0.87%	-0.39%
6	Real Disposable Personal Income		0.53%	0.93%	1.44%	0.91%	0.61%	1.40%	2.00%	0.21%	1.38%	0.34%	0.48%
	Annualized Percentage Change From Previous Qtr.												
7	Real GDP		3.7%	4.4%	4.7%	7.2%	2.7%	2.2%	4.4%	1.2%	5.7%	2.6%	4.2%
8	Manuf Production		2.7%	0.3%	4.7%	1.5%	4.9%	4.5%	6.8%	14.1%	7.8%	3.5%	-1.6%
9	Real Disposable Personal Income		2.1%	3.7%	5.8%	3.6%	2.4%	5.6%	8.0%	0.8%	5.5%	1.3%	1.9%

* - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted upward by 8730/8013.
** - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted downward by 1148/1369.
*** - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted upward by 6264/5796.

Source: Energy Information Administration/Short-Term Energy Outlook- Dec. 1999, Dec. 2000, Dec. 2001, and Feb. 2002. Table 1

Exhibit No.___(JSG-4)
Schedule 2
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Line No.	Description	2001 1st Qtr.	2001 2nd Qtr.	2001 3rd Qtr.	2001 4th Qtr.Est.	2002 Estimated 1st Qtr.	2002 Estimated 2nd Qtr.	2002 Estimated 3rd Qtr.	2002 Estimated 4th Qtr.	2003 Estimated 1st Qtr.	2003 Estimated 2nd Qtr.	2003 Estimated 3rd Qtr.	2003 Estimated 4th Qtr.
1	Real GDP *	9,334	9,342	9,317	*9,284*	*9,288*	*9,353*	*9,435*	*9,547*	*9,641*	*9,742*	*9,821*	*9,915*
2	Manuf Production **	1,221	1,202	1,186	*1,155*	*1,153*	*1,159*	*1,170*	*1,194*	*1,221*	*1,253*	*1,284*	*1,305*
3	Real Disposable Personal Income ***	6,679	6,719	6,919	*6,788*	*6,899*	*6,888*	*6,940*	*7,001*	*7,082*	*7,168*	*7,213*	*7,255*
	Percentage Change From Previous Qtr.												
4	Real GDP	0.66%	0.60%	2.98%	-1.89%	1.64%	-0.16%	0.75%	0.88%	1.16%	1.21%	0.63%	0.58
5	Manuf Production	-3.63%	-1.56%	-1.33%	-2.61%	-0.17%	0.52%	0.95%	2.05%	2.26%	2.62%	2.47%	1.64%
6	Real Disposable Personal Income	0.32%	0.09%	-0.27%	-0.35%	0.04%	0.70%	0.88%	1.19%	0.98%	1.05%	0.81%	0.96%
	Annualized Percentage Change From P												
7	Real GDP	2.7%	2.4%	11.9%	-7.6%	6.5%	-0.6%	3.0%	3.5%	4.6%	4.9%	2.5%	2.3%
8	Manuf Production	-14.5%	-6.2%	-5.3%	-10.5%	-0.7%	2.1%	3.8%	8.2%	9.0%	10.5%	9.9%	6.5%
9	Real Disposable Personal Income	1.3%	0.3%	-1.1%	-1.4%	0.2%	2.8%	3.5%	4.7%	3.9%	4.2%	3.2%	3.8%

* - In 1999 the base year changed from
** - In 1999 the base year changed from
*** - In 1999 the base year changed from

Source: Energy Information Administrat

Exhibit No.___(JSG-4)
Schedule 2
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MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota
Case No. PU-399-01-186

Surrebuttal Testimony
of
Douglass A. Mahowald

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

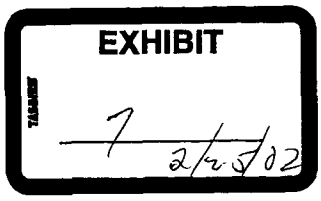
A. Yes. My name is Douglass A. Mahowald and my business address is 918 E. Divide Ave, Bismarck North Dakota, 58506. I am the Assistant Treasurer and Assistant Secretary of MDU Resources Group, Inc.

Q. Would you please describe your duties as Assistant Treasurer and Assistant Secretary?

A. As Assistant Treasurer and Assistant Secretary, I am responsible for the treasury services functions of the Company, including the Company's cash management program, maintaining bank and financial relationships, administration of the Company's short and long-term debt financing program, financial analysis, and debt compliance. I assist in the administration of various benefit plans and the Company's risk management (hedging) program.

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

A. In 1972, I received a Bachelor of Arts degree in Business Administration, with a concentration in finance, from the University of St. Thomas, St. Paul, Minnesota. Upon graduating from the University of St. Thomas, I held various accounting and financial positions with several



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Surrebuttal Testimony of Douglass A. Mahowald
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
02/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike

firms in Minot, North Dakota and Minneapolis, Minnesota. In February 1982, I joined Montana-Dakota as Budget Statistician. I was promoted to Treasury Services Manager in November 1982. In that capacity, I was responsible for treasury service functions, including the Company's cash management program. In August 1992, I was promoted to Assistant Treasurer and Assistant Secretary of MDU Resources Group, Inc.

Q. Have you previously testified in proceedings before regulatory agencies?

A. Yes. I have testified before the Montana Public Service Commission and the Wyoming Public Service Commission.

Q. What is the purpose of your testimony?

A. The purpose of my surrebuttal testimony is to describe the debt refinancing that incurred in April of 1992, which is referenced in the surrebuttal testimony of Dr. Gaske.

Q. What did the Company refinance in 1992?

A. The Company refinanced $100,000,000 of First Mortgage Bonds represented by the five series of bond issues shown under the Pre-Refinancing heading on page 1 of my attached Exhibit No.___ (DAM –1). That long-term debt was replaced with the issues shown under the Post-Refinancing heading shown on page 1 of the exhibit.

Q. Why did the Company refinance the First Mortgage Bonds in 1992?

A. The Company's primary objective in refinancing its long-term debt in 1992 was to lower the overall cost of its long-term debt. The Company achieved this objective through the refinancing that was completed at that

time. This is shown on Exhibit No.___ (DAM-1). Page 1 of the exhibit is a comparison of the cost of the issues redeemed and the cost of the new issues, which replaced the redeemed issues. As shown, the pre-refinancing coupon interest rate for the group was 9.258% and the post-refinancing coupon interest rate for the group was 7.657%. Also, as shown on page 1, the pre-refinancing costs for the group was 10.215% and the post-refinancing costs for the group was 9.508%. This resulted in an annual savings of $231,500. Page 2 of the exhibit shows Montana-Dakota's total embedded cost of long term debt at 9.965% for the twelve months ending December 31, 1991, immediately before the refinancing. Page 3 of the exhibit shows the total embedded cost of long term debt at 9.69% for the twelve months ending December 31, 1992, or immediately after the refinancing. This exhibit clearly shows that the Company was able to lower its cost of the issues redeemed as well as lower its total cost of long term debt by .275% through this refinancing in 1992. This lower cost of long-term debt has been a direct benefit to the Company's customers.

Q. Has the company considered refinancing this debt that was refinanced in 1992?

A. Yes. The company has considered refinancing this group of long-term debt issues. However, the company has not taken any formal action to refinance this debt because this action would cause an increase in the total costs.

Q. Why would refinancing now at what appear to be lower coupon rates increase the total costs?

A. In order to lower the overall cost of its long-term debt in 1992 and provide a direct benefit to its customers, the company issued debt at then prevailing interest rates and market conditions. Based on the current prevailing interest rates, the company anticipates that refinancing this group of existing long-term debt issues may lower the overall interest coupon rate for the group. However, the company would incur significant costs to reacquire this debt from existing holders in order to refinance. After accounting for the reacquisition costs for this group of existing long-term debt issues, most notably the loss on reacquired debt, any refinancing action would increase the overall embedded cost of the company's existing long-term debt and penalize its customers.

Q. Does this complete your testimony?

A. Yes, it does.

REFINANCED FIRST MORTGAGE BONDS

Pre-Refinancing

Issue	Principal Outstanding	Coupon Interest	Cost of Money Rate
8.50%, due10-1996	$ 2,500,000	8.500%	9.052%
8.625%, due 10-2001	9,400,000	8.625%	9.061%
9.00%, due 9-1998	3,500,000	9.000%	9.534%
9.25%, due 9-2003	9,400,000	9.250%	9.667%
9.375%, due 11-2011	75,200,000	9.375%	10.498%
Total / Average Rate	$ 100,000,000	9.258%	10.215%

Post-Refinancing

Issue	Principal Outstanding	Coupon Interest	Cost of Money Rate
5.80%, due4-1994	$ 15,000,000	5.800%	7.019%
6.30%, due 4-1995	10,000,000	6.300%	7.591%
6.95%, due 4-1996	10,000,000	6.950%	8.297%
7.20%, due 4-1997	5,000,000	7.200%	8.593%
8.25%, due 4-2007	30,000,000	8.250%	10.179%
8.60%, due 4-2012	35,000,000	8.600%	11.024%
Total / Average Rate	$ 105,000,000	7.657%	9.508%

Interest Costs

	Coupon Basis	Cost of Money Basis
Pre-Refinance	$ 9,257,800	$ 10,214,900
Post-Refinance	8,039,955	9,983,400
Net Interest Savings	$ 1,217,845	$ 231,500

MDU RESOURCES GROUP, INC.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 1991

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue (000's)	Gross Proceeds (000's)	Underwriters' Commission		Issuance Expense	
						Amount	% Gross Proceeds	Amount	% Gross Proceeds
Serial Bonds: 7 1/8%	11/01/68	11/01/93	7.125%	$10,000	$10,029	$109,670	1.094%	$90,875	0.906%
8 5/8%	10/01/76	10/01/01	8.625%	10,000	9,963	52,300	0.525%	128,850	1.293%
9 1/4%	09/15/78	09/15/03	9.250%	10,000	9,951	33,200	0.334%	102,400	1.029%
10 1/4%	05/15/79	05/15/04	10.250%	25,000	24,938	173,500	0.696%	214,767	0.861%
9 3/8%	11/15/86	11/15/11	9.375%	80,000	79,600	700,000	0.879%	4,543,078	5.707%
9 1/8%	05/15/91	05/15/06	9.125%	50,000	49,893	271,500	0.544%	4,303,963	8.62[illegible]
Sinking Fund Bonds:									
7 5/8%	10/15/72	10/15/92	7.625%	20,000	20,100	144,600	0.719%	137,025	0.682%
8 1/2%	10/01/76	10/01/96	8.500%	10,000	10,000	76,900	0.769%	128,850	1.289%
9%	10/01/78	09/15/98	9.000%	10,000	9,945	44,800	0.450%	90,799	0.913%
Pollution Control Revenue Bonds:									
Grant County	03/01/74	03/01/04	6.200%	$5,600	$5,600	$84,000	1.500%	$88,958	1.589%
Morton County	08/01/74	08/01/04	7.830%	4,800	4,800	132,600	2.763%	72,832	1.517%
Richland County	03/01/75	03/01/05	7.932%	4,000	4,000	90,000	2.250%	53,679	1.342%
Mercer County	05/01/79	05/01/04	7.125%	8,000	8,000	84,000	1.050%	71,411	0.893%
Mercer County	05/01/79	05/01/09	7.200%	7,000	7,000	73,500	1.050%	62,486	0.893%
Grant County	10/15/81	10/15/11	14.000%	3,000	2,970	45,000	1.515%	51,114	1.721%

Description	Net Proceeds		Cost of Money 1/	Principal Outstanding (000's)	Annual Cost	Embedded Cost
	Amount	Per Unit				
Serial Bonds: 7 1/8%	$9,828,455	98.285%	7.415%	$9,400	$697,010	
8 5/8%	9,781,850	97.819%	9.061%	9,400	851,734	
9 1/4%	9,815,400	98.154%	9.667%	9,400	908,698	
9 3/8%	74,356,922	92.946%	10.498%	75,200	7,894,496	
9 1/8%	45,317,037	90.634%	11.045%	50,000	5,522,500	
9 1/8%	45,317,037	90.634%	10.542%	20,000	2,108,400	
TOTAL				$173,400	$17,982,838	10.371%
Sinking Fund Bonds:						
7 5/8%	19,818,375	99.092%	7.926%	1,000	79,260	
8 1/2%	9,794,250	97.943%	9.052%	2,500	226,300	
9%	9,809,401	98.094%	9.534%	3,500	333,690	
TOTAL				$7,000	$639,250	9.132%
Pollution Control Revenue Bonds:						
Grant County	$5,427,042	96.911%	6.556%	$5,200	$340,912	
Morton County	4,594,568	95.720%	8.353%	2,600	217,178	
Richland County	3,856,321	96.408%	8.400%	3,250	273,000	
Mercer County	7,844,589	98.057%	7.428%	8,000	594,240	
Mercer County	6,864,014	98.057%	7.500%	7,000	525,000	
TOTAL				$26,050	$1,950,330	7.487%
TOTAL				$206,450	$20,572,418	9.965%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

Case No. PU-399-01-186
Exhibit No. ____(DAM-1)
Page 2 of 3

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 1992

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Issuance Expense Amount	Issuance Expense % Gross Proceeds
Serial Bonds:									
9 1/8%	05/15/91	05/15/06	9.125%	$50,000,000	$49,892,500	$271,500	0.544%	$4,691,400	9.403%
9 1/8%	10/01/91	10/01/16	9.125%	20,000,000	20,000,000	127,600	0.638%	1,567,169	7.836%
5.8% MTN	04/01/92	04/01/94	5.800%	15,000,000	14,993,700	52,500	0.350%	244,592	1.631%
6.3% MTN	04/01/92	04/01/95	6.300%	10,000,000	9,990,000	50,000	0.501%	244,592	2.448%
6.95% MTN	04/01/92	04/01/96	6.950%	10,000,000	9,989,200	60,000	0.601%	326,122	3.265%
7.2% MTN	04/01/92	04/01/97	7.200%	5,000,000	4,990,900	31,250	0.626%	203,826	4.084%
8.25% MTN	04/01/92	04/01/07	8.250%	30,000,000	30,000,000	225,000	0.750%	3,668,876	12.230%
8.6% MTN	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,707,140	16.348%
Pollution Control Revenue Bonds:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	937,892	6.253%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,142	5.727%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	178,870	6.880%

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
Serial Bonds:						
9 1/8%	$44,929,600	89.859%	11.045%	$50,000,000	$5,522,500	
9 1/8%	18,305,231	91.526%	10.548%	20,000,000	2,109,600	
5.8% MTN	14,696,608	97.977%	7.019%	15,000,000	1,052,850	
6.3% MTN	9,695,408	96.954%	7.591%	10,000,000	759,100	
6.95% MTN	9,603,078	96.031%	8.297%	10,000,000	829,700	
7.2% MTN	4,755,824	95.116%	8.593%	5,000,000	429,650	
8.25% MTN	26,106,124	87.020%	10.179%	30,000,000	3,053,700	
8.6% MTN	28,897,710	82.565%	11.024%	35,000,000	3,858,400	
				175,000,000	17,615,500	10.066%
Pollution Control Revenue Bonds:						
Grant County 6.2%	5,427,042	96.911%	6.556%	5,000,000	327,800	
Mercer County 6.65%	14,062,108	93.747%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,858	94.273%	7.241%	3,250,000	235,333	
Morton County 6.65%	2,421,130	93.120%	7.344%	2,600,000	190,944	
				25,850,000	1,847,277	7.146%
TOTAL				$200,850,000	$19,462,777	9.690%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

Case No. PU-399-01-186
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MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
Of
Roger Joseph Schiffman

INTRODUCTION

Q. Please state your name, business address and position?

A. My name is Roger Joseph Schiffman and my business address is 3100 Zinfandel Drive, Suite 600, Rancho Cordova, CA 95670-6026. I am employed as a Principal Consultant in the Energy and Water Practice (EWP) of Navigant Consulting, Inc., (NCI). I have been employed by NCI since March, 2000.

Q. Please describe NCI's business and your role and responsibilities.

A. NCI is a national management consulting firm specializing in the energy industry. The Energy and Water Practice (EWP) provides services to all segments of the restructured energy industry (generation or production, transmission, distribution, and retail supply) and is a leading provider of planning and engineering services to the water industry. Our existing energy sector client base includes most of the largest utilities in the United States, most of the independent power producers, and a number of municipal utilities. NCI is active in all North American electricity markets.

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Surrebuttal Testimony of Roger Joseph Schiffman
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
02/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Within NCI, I manage a group that focuses upon electricity market assessment and analysis. Exhibit_____(RJS-1) lists my detailed experience. One of the key services provided by my group centers on wholesale electricity market price forecasts derived using detailed computer simulation models. Within the last 4 years, I have prepared forecasts of electricity market prices in all North American regional power markets, including the Mid-Continent Area Power Pool (MAPP). These forecasts have been used by consulting clients for several purposes including supply portfolio planning and procurement, contract evaluation, asset valuation, and feasibility analysis. A number of the forecasts have also been used to support revenue projections underlying project financing deals for new merchant power plants. Within the last year, I have also been heavily involved in NCI's engagement with the California Department of Water Resources in that agency's efforts to structure a portfolio of power supply contracts and to obtain a targeted $13 billion in new financing. Preparation of detailed forecasts requires constant attention to supply and demand fundamentals in each of the North American market regions, in addition to careful evaluation of regulatory and market developments.

Q. Please describe your professional experience prior to joining NCI.

A. From 1998 through March, 2000, I was employed as a Senior Consultant by Henwood Energy Services, Inc ("HESI"). My duties at HESI were similar to those at NCI, and included electricity market assessment,

electricity market price forecasting, generating asset valuation, gathering market analysis and intelligence, and completing a variety of financial and cost evaluation projects for consulting clients.

From 1990 through 1998, I was employed as a Financial Analyst at the Public Service Commission of Wisconsin. My job responsibilities included policy development and analysis, economic and cost analysis, evaluation of competitively bid power supply proposals, integrated resource planning, advising the Wisconsin Commission on rate of return and capital structure, and conducting specialized studies concerning public utility finance, economics and regulatory policy.

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration in Finance, Investment and Banking from the University of Wisconsin-Madison in 1988. From 1988 through 1990 I engaged in graduate studies in finance, also at the University of Wisconsin-Madison.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What is the purpose of your testimony?

A. I will address wholesale bulk power market conditions over the past several years as well as the outlook for 2002, and more specifically, the impact of these conditions on the level and profitability of Montana-Dakota's off-system sales. While many of these conditions are common

across the United States, I will also address the conditions in the market that Montana-Dakota sells into, the MAPP.

Q. What are your key conclusions?

A. Staff Witness Mike Diller proposes that the level of off-system sales margins experienced in 2001 (with minor adjustments), be reflected in rates that will be in effect in 2002 and beyond. However, 2001 was hardly a "normal" or "average" year in any respect, and conditions in the both natural gas and electricity wholesale markets changed in very significant ways throughout the year. As in all competitive markets, the fundamental demand and supply conditions explain the 2000-2001 experience, and define the outlook for 2002.

MARKET CONDITIONS AFFECTING MONTANA-DAKOTA'S OFF-SYSTEM SALES REVENUES

Q. What are the primary determining factors of Montana-Dakota's off-system sales revenues?

A. In simple terms, Montana-Dakota's margins from off-system sales are determined by the level or quantity of sales and the profit margin (revenue minus cost) that it is able to obtain from each sale.

The opportunity to make off-system sales is created by the gap between the price of purchases and sales opportunities in the spot market, and Montana-Dakota's cost of powering its own generating units, which are primarily coal-fired. Spot market prices in the MAPP region where Montana-Dakota operates can vary substantially with the price of natural gas and with the fuel efficiency of units "on the margin." For Montana-Dakota to make a profitable sale the gap, or profit margin, must be sufficient to offset incremental operating costs and to provide adequate incentive to increase production levels and to compensate for any risk associated with the transaction. Thus, the profit margin is the primary determinant of the quantity of off-system sales that Montana-Dakota is able to make in a given period.

The margins that Montana-Dakota is able to obtain are determined by the size of this fuel cost differential as well as fundamental demand and supply conditions that affect the markets that Montana-Dakota is able to reach. Demand and supply conditions are important because the so-

called "spark spread", the difference between wholesale electricity and natural gas prices, will vary in response to changing demand and supply conditions.

Q. Which markets does Montana-Dakota sell into?

A. Montana-Dakota sells primarily into upper midwest wholesale markets in the MAPP, Mid-American Interconnected Network (MAIN) and Southwest Power Pool (SPP) regions. The northern MAPP region where Montana-Dakota's generators are located can be characterized as a relatively low cost market. Trade patterns in the upper midwest are such that energy tends to flow from the northern and western MAPP region toward higher cost markets in eastern MAPP, MAIN and SPP. MAPP power markets are sometimes impacted by transmission constraints that limit export opportunities, particularly the amount of energy that can flow simultaneously in the easterly direction toward the Wisconsin Upper Michigan Systems (WUMS) subregion of MAIN, and in the southerly direction toward the St. Louis area.

Q. What factors do you consider important when comparing wholesale power market conditions from year to year?

A. Wholesale power markets operate in a competitive landscape, where numerous influences combine to create changes in the market environment. Weather, fuel prices, economic growth, generation mix and the supply/demand balance all play important roles in defining trends in the broader wholesale power markets. Indeed, these are all important

quantitative inputs in the complex computer models many companies use to forecast power pricing, and are critical factors in real-time market operations.

Q. How have fundamental market conditions evolved in North American power markets over recent years?

A. U.S. wholesale power markets have undergone significant evolution in recent years, in response to deregulation policies implemented in a number of states, and in response to continued efforts by the Federal Energy Regulatory Commission (FERC) to establish fair and open transmission access. The extent of market reforms has varied by region. During this period of transition toward competitive markets, wholesale electricity prices have exhibited considerable volatility. The levels of price volatility have also varied by region, and have sometimes resulted primarily from rapidly changing supply and demand conditions. In some circumstances, the levels of volatility witnessed in regional markets has also been due to the temporal exercise of market power by suppliers, or due to institutional inefficiencies in organizations and market rules meant to regulate market operations in a particular region.

Q. Please expand on the experience of price volatility in the Midwest region.

A. During the summer of 1998 and 1999, significant price volatility was first seen in midwest power markets. Several fundamental supply conditions contributed to the price volatility seen in that period. In the early to mid 1990s, development of new generating supply had lagged in

many midwest markets as the future role of investor-owned utilities in the generation market became uncertain with the advance of deregulation. With uncertainty over which entities would be responsible for serving native load customers, and significant risks of stranded cost exposure in the face of declining demand levels, utility companies and their investors became reluctant to make large investments in new capital intensive power plants. As such, demand growth during that period outpaced growth in the supply base in many regions.

Beginning in late 1997, several nuclear plants in the upper midwest region faced extended outages to repair cracks that had surfaced in the steam generators. At the same time, the Nuclear Energy Regulatory Commission began a rigorous review of its safety regulations governing nuclear plant operation. The combination of physical repairs and more stringent safety regulations resulted in extended outages of an unprecedented amount of midwest nuclear capacity during the summer of 1998 and 1999. Those supply conditions were further exacerbated when similar concerns with safety compliance forced several nuclear plants in Ontario, Canada into extended outage. The net result was critical supply shortages in the upper midwest during that period, with over 7,000 MW of nuclear capacity out of service in the midwest and an additional 5,000 MW of nuclear capacity out of service in Ontario. Those outages led to significant price volatility during the summer months. At their peak,

reported wholesale power prices reached $1,250/MWh in July, 1998 and $1,426/MWh in July, 1999 in the MAPP region.

With the return to service of the nuclear capacity in the MAIN and ECAR regions, and additional generating supply coming into midwest markets, price volatility returned to more normal levels during 2000.

Q. What fundamental market conditions occurred during 2001 that indicate it was an abnormal year?

A. As discussed by Mr. Blinsky, Mr. Wilkinson and Mr. Gaske, a key factor underlying electricity market dynamics in 2001 concerned the unprecedented increase in natural gas prices witnessed during the last quarter of 2000, and the first two quarters of 2001. During that period, high natural gas prices resulted in significantly increased spot market electricity prices throughout the United States. That pattern is illustrated in Mr. Wilkinson's Exhibit PLW-1.

Within the MAPP region, natural gas-fueled generators have been playing an increasingly prominent role in establishing spot market clearing prices. This pattern occurs because a significant portion of new entry in MAPP has been fueled by natural gas and those new resources operate as intermediate and peaking resources. Gas-fired generators in MAPP now occupy an expanding segment of the supply curve that represent the marginal resource with increasing frequency. The correlation between MAPP electricity and natural gas prices has been increasing in recent

years due to this factor, and will continue to strengthen as gas-fired resources represent an expanding portion of generating supply.

In addition to the run-up in natural gas prices seen in late 2000 and the first half of 2001, the supply crisis in Western U.S. power markets, and particularly in California, also played an important role in electricity price discovery in other U.S. markets. While the power systems in the eastern (and midwest) U.S. operate asynchronously to those in the western U.S., the level of sustained abnormal prices seen in California had an impact on price discovery in all domestic power markets. The extent of the crisis that arose in California was beyond anyone's expectations, and drew significant attention throughout the world. From a risk management perspective, market participants in all market regions were required to reevaluate their hedging strategies in response to the magnitude of prices and reliability difficulties seen in California. The financial distress faced by the California investor-owned utilities were also factors that far exceeded prior expectations. The supply crisis reached a level so serious that the State of California was required to step in and assume the role of spot market broker and financier. Absent that step, frequent and sustained blackout periods would have occurred during the first half of 2001, and perhaps throughout the year. A crisis of that magnitude was clearly an abnormal event.

Q. What steps did energy market participants take in response to increased natural gas price levels and in response to market uncertainties created by the supply crisis in California?

A. Market participants that faced significant price risk in electricity and natural gas spot markets early in 2001 took actions to mitigate a portion of that risk on a going-forward basis. In the short-term, risk mitigation measures involved entering into short-term or intermediate-term bilateral contracts designed to create improved price certainty, and to hedge against extreme upside price volatility. This type of hedging activity was a rational response to extreme uncertainties in both natural gas and electricity markets. Because of the level of volatility seen in both natural gas and power markets during late 2000 and early 2001, the risk premiums underlying such hedging arrangements were quite high by historical standards.

A concrete example of the hedging activity I am describing is illustrated in Mr. Blinsky's surrebuttal testimony, and has direct relevance to projecting the margin on Montana-Dakota's off-system sales. As described in Mr. Blinsky's testimony, Montana-Dakota entered into a sales agreement in March of 2001, which locked in summer electricity prices and sales revenue based on the prices of futures contracts in place at that time. When spot market natural gas and electricity prices declined during the last half of the year, Montana-Dakota enjoyed a higher profit margin based on its contracting position than it would have earned selling power

directly at spot market prices. Under current market conditions, contracting opportunities such as that enjoyed by Montana-Dakota are no longer available because the premium between contract and spot market prices is substantially smaller.

Q. What impact have these fundamental energy market conditions had on market prices in late 2000 and 2001?

A. The price spikes we observed recently in the winter of 2000-2001 were clearly an anomaly. In fact, winter peak wholesale power prices have historically varied between $25-$35/MWh and had only ever reached around $40/MWh in the winter of 1999-2000.

With higher natural gas prices and greater market uncertainty, wholesale power prices in MAPP reached $142/MWh during the on-peak period of December 12, 2000. This level was, in fact, higher than the previous and following summer peaks of $120/MWh reached in August 2000 and August 2001, respectively. Off-peak pricing also increased during the winter of 2000-2001, reaching slightly more than $47/MWh for the first time recent history. Normally, off-peak pricing in MAPP runs between $10 - $15/MWh. Since natural gas resources are rarely marginal in the MAPP region during off-peak periods, this level of off-peak prices suggests significant risk premiums being priced into wholesale electricity prices. Exhibit_____(RJS-2) illustrates daily spot market electricity prices in the MAPP region for the period beginning January, 1996 through February, 2002.

Q. How have the electricity price levels seen in late 2000 and the first half of 2001 impacted the margin earned on off-system sales by Montana-Dakota during that period?

A. With continued coal price stability, the run-up in natural gas prices and risk premiums priced into short-term and intermediate-term bilateral transactions resulted in abnormally high profit margins for coal-fired generators throughout the first months of 2001.

That pattern can be seen in Exhibit (RJS-3), where daily coal-based and natural-gas based spark-spreads are plotted for the period January, 1996 through February, 2002. Exhibit_____(RJS-4) plots the spark-spread data on a monthly basis for the same period, while Exhibit_____(RJS-5) plots the same monthly spark-spread data for just the period January, 2000 through February, 2002.

The spark-spread represents the margin above fuel costs achievable by operation of a given power plant. In estimating the spark-spread, we have assumed market heat rates of 7,000 Btu/kWh for gas-fired generation, and 12,000 Btu/kWh for coal-fired generators. The coal-based spark-spread measure provides a representation of the margin that Montana-Dakota could be expected to earn on off-system sales, but does not net out additional costs attributed to nonfuel operations and maintenance. As shown in Exhibit_____(RJS-4) and Exhibit_____(RJS-5), the coal-based spark-spread departs significantly from the natural gas-based spark-spread during the period of high natural gas prices

experienced in the fourth quarter of 2000, and the first half of 2001. During the last half of 2001 and the first two months of 2002, when natural gas prices returned to equilibrium levels, the two spark-spread measures returned to their normal historical pattern and tracked each other closely. The abnormal departure of coal-based and natural gas-based spark-spreads illustrated in Exhibit_____(RJS-5) directly corresponds with the period of abnormally high margins on off-system sales enjoyed by Montana-Dakota during 2001. As shown in this exhibit, coal and natural gas-based spark-spreads track each other very closely throughout the second half of 2001.

2002 MARKET OUTLOOK

Q. Are current natural gas and electricity market fundamentals such that you would expect repeated electricity price spikes and continued abnormally high profit levels on Montana-Dakota's off-system sales?

A. No. Market fundamentals for 2002 and subsequent near-term years suggest a period of improved stability in wholesale power markets. As discussed by Mr. Blinksy, Mr. Wilkinson and Mr. Gaske, natural gas prices have returned to more normal levels, and the current outlook is for natural gas price stability. In wholesale electricity markets, a combination of new supply coming on-line, reduced demand from targeted conservation programs, and institutional market reforms have contributed to price stability again in the western U.S. market. That stability has been bolstered by a return to normal (or perhaps wet-year) hydro conditions in the western U.S. and by the increase of bilateral contracts entered into to hedge against upward price volatility.

In midwest power markets, supply expansion is also expected to improve supply/demand margins and contribute to electricity price stability. Exhibit_____(RJS-6) lists estimated historical and 2002 projected reserve margin levels in the MAPP, MAIN and SPP market regions. As shown, reserve levels reached their floor during 1999 and 2000, and are projected to continue their rebound during 2002. This combination of factors points to lower and more stable wholesale electricity prices in the MAPP region for 2002, compared to the price and volatility levels seen over the last four

years, and particularly during the first-half of 2001. As discussed by Mr. Blinsky, this expectation of reduced price volatility is reflected in current market expectations and prices of NYMEX futures contracts for on-peak power delivered into the Cinergy hub. Buyers and sellers in future markets place great weight on their fundamental supply and demand issues.

Q. Given your expectation of likely 2002 wholesale power market conditions in the midwest region, do you believe Montana-Dakota will enjoy profit margins on off-system sales that are comparable to the levels earned during 2001?

A. No, with lower and more stable natural gas and electricity prices, profit margins on off-system sales will be correspondingly lower. Reduced price volatility will result in a lower risk premium being priced into wholesale market transactions. In addition, as supply expands and supply/demand balances improve, Montana-Dakota will face greater competition for off-system sales. With lagging electricity sales due to the current economic downturn, that competition will only be greater and Montana-Dakota might face reduced volumes of off-system sales, in addition to lower profit margins on those sales. As discussed above, natural gas and electricity price volatility created the increased margins for Montana-Dakota in the winter of 2000-2001 because Montana-Dakota retained its relatively flat cost structure relative to natural gas-burning

competitors. With more stable prices going forward, the margins available on off-system sales will be lower.

In summary, market conditions toward the end of 2001 are significantly more representative of what can be expected in 2002 and for the foreseeable future.

Q. Do you believe the approach used by Mr. Blinsky for forecasting margin on off-system sales is reasonable?

A. Yes, I believe Mr. Blinsky uses a reasonable approach. Forecasting energy market prices is always a difficult exercise, and using the prices of currently traded futures contracts is a reasonable way to assess current market expectations of spot market prices that will prevail during the relevant months of 2002.

Q. Does that conclude your testimony?

A. Yes it does.

Mr. Schiffman is a Principal Consultant at Navigant Consulting, Inc. He is responsible for managing the price forecasting subpractice within Navigant Consulting's Energy Market Assessment group. In that role, he develops market price forecasts reflecting competitive changes in the electric industry, financial analyses and performs simulation of power system operations using the Electric Market Simulation System (EMSS) and PROSYM chronological production simulation system. Mr. Schiffman has over twelve years of experience covering a broad range of energy industry issues including electricity market evaluation, price forecasting, contract evaluation, regulatory policy development, utility resource planning, tariffed pricing, cost of capital and discount rate analysis, and general economic and financial analysis. Mr. Schiffman has extensive experience working with electric utility staff, power plant developers, regulatory personnel, and other industry participants in consulting and regulatory environments.

PROFESSIONAL HISTORY

Navigant Consulting, Inc. (2000-Present)
Principal Consultant

Henwood Energy Services, Inc. (1998-2000)
Senior Consultant

Public Service Commission of Wisconsin (1990-1998)
Senior Financial Analyst

University of Wisconsin (1989-1990)
Research Assistant

RELEVANT PROJECT EXPERIENCE

Electricity Market Assessment

Prepared numerous assessments and forecasts of wholesale market electricity prices in U.S. and Canadian markets. The market assessments have been used by clients for asset valuation, portfolio procurement decisions, contract evaluation, merchant plant financing transactions, pollution control investment decisions, investment feasibility studies, resource planning, and for a variety of other purposes. Developed Reference Case electricity price forecasts for the WSCC, Ontario, New England, New York and ECAR market regions.

Directed market evaluation and revenue forecast for two major merchant power plants in Texas. Presented revenue forecast to investment bankers and to potential equity investors. Advised and worked with project developers to obtain debt and equity financing for the

projects. Conducted economic study of market rules and entry barriers faced by developers of new merchant power plants in domestic electricity markets.

Developed electricity price forecasts used in financing transactions for several merchant power plants in California, Texas, Arizona, and Colorado.

Advised and collaborated with PricewaterhouseCoopers to perform economic evaluation and market simulations of proposed Purchase Power Arrangements under development in Alberta, Canada, and scheduled for auction in 2000.

Electricity Market Power Studies

Directed preliminary study analyzing market power issues surrounding Pacific Gas & Electric Company's proposed divestiture of its hydro-electric assets.

Participated in economic study of market power held by incumbent electricity suppliers in Alberta, Canada.

Conducted economic study of market power in Wisconsin electricity markets in support of Madison Gas & Electric Company's application for market-based pricing authority before the Federal Energy Regulatory Commission.

Developed regulatory policies for addressing wholesale and retail market power in Primergy and Interstate Energy Corporation merger cases. Evaluated feasibility and corporate finance implications of asset divestiture and spin-off options for mitigating market power.

Competitive Bid Evaluations

Prepared economic and engineering analyses of power plant proposals submitted in two generation competitive bidding solicitations. Prepared financial analyses of key contract terms and risks. Evaluated economic and engineering characteristics of bid proposals using production cost and system expansion computer modeling.

Regulatory Policy Proposals

Developed policy proposals for restructuring wholesale and retail electricity markets. Evaluated competing policy proposals for impacts upon electricity consumers and upon electrical system operation. Drafted formal electricity industry restructuring policy adopted by the Public Service Commission of Wisconsin.

Presented evaluation of proposed electric utility merger legislation to subcommittee of Wisconsin legislature. Advised individual legislators on merger policy. Participated in

development of policy proposals and draft legislation for reforming power plant siting law and for allowing development of new merchant power plants in Wisconsin.

Directed industry-wide efforts to revise the Public Service Commission of Wisconsin generation competitive bidding procedures. Conducted workshops on proposed revisions for utility and other industry participants. Drafted policy reforms adopted by the Wisconsin Commission.

Resource Planning

Evaluated supply plans proposed by investor-owned utilities in MAIN and MAPP regions. Evaluation included cost and risk evaluation, system expansion modeling, and review of transmission plans. Prepared revised resource plans.

Cost of Capital Analyses

Prepared numerous cost of capital and discount rate analyses. Presented testimony before Public Service Commission of Wisconsin.

Models

Performed market clearing price studies and asset evaluations using PROSYM, GenWiz, and MarketPower chronological models. Performed resource planning and competitive bid evaluation using the RP Workstation which incorporates EGEAS, DSMLINK, RISKMIN, and FINANCE+. Developed numerous spreadsheet and database tools to evaluate investment and capital budgeting decisions, nuclear decommissioning trust fund asset allocation, volatility analysis, and to evaluate a variety of other economic and financial issues.

Education

B.S., Business Administration, Finance, Investment and Banking, University of Wisconsin-Madison, 1988

Publications

Electric Utility Mergers and Regulatory Policy, Ray, Stevenson, Schiffman, Thompson. National Regulatory Research Institute, 1992.

The Future of Wisconsin's Electric Power Industry: Environmental Impact Statement, co-author, Public Service Commission of Wisconsin, October 1995, Docket 05-EI-114.

Report to the Governor on Electric Reliability, co-author, Public Service Commission of Wisconsin, Summer 1997.

Testimony

Public Service Commission of Wisconsin, Docket 6630-UR-104, Wisconsin Electric Power Company Rate Case, 1990, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6690-UR-106, Wisconsin Public Service Corporation Rate Case, 1991, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-105, Northern States Power Company (Wisconsin) Rate Case, 1991, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Rate of Return on Equity, Cost of Capital and Financial Condition, Wisconsin Electric Power Company, Docket 6630-UR-105, Public Service Commission of Wisconsin, 1991

Public Service Commission of Wisconsin, Docket 05-EP-6, Advance Plan 6, 1992, "Alignment of Managerial Interests and Incentives with Integrated Resource Planning Goals" (with Paul Newman).

Public Service Commission of Wisconsin, Docket 6680-UR-107, Wisconsin Power & Light Company Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-106, Northern States Power Company (Wisconsin) Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-UR-106, Wisconsin Electric Power Company Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 05-EI-112, Investigation on the Commission's Own Motion Into Barriers to Contracts Between Electric Utilities and Non-Utility Cogenerators and Certain Related Policy Issues, 1992, "Contract Risk in Long-Term Purchase Power Arrangements."

Public Service Commission of Wisconsin, Docket 3270-UR-106, Madison Gas and Electric Company Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-CE-187, Wisconsin Electric Power Company, 1993, "Memorandum to Commission Presenting Economic Analysis of Competitively Bid Proposals for New Power Plants" (co-authored).

Public Service Commission of Wisconsin, Docket 6680-UR-108, Wisconsin Power & Light Company Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-107, Northern States Power Company (Wisconsin) Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6680-UR-109, Wisconsin Power & Light Company Rate Case, 1994, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-CE-202, Wisconsin Electric Power Company Auburn to Butternut Transmission Line Case, 1994, "Economic Cost Comparison of Transmission Upgrade and Distributed Generation Wind Turbine Project."

Public Service Commission of Wisconsin, Docket 3270-UR-107, Madison Gas and Electric Company, 1994 "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin,. Docket 6690-CE-156, Application of Wisconsin Public Service Corporation for Authority to Increase Electric Generating Capacity (Stage One Competition Among Alternative Suppliers), 1994 & 1995, "Economic Analysis of Competitively Bid Power Plant Proposals" (with Paul Newman), "Contract Risk in Purchased Power Arrangements," "Accounting Treatment for Long-Term Purchased Power Contracts," "Contract Risk and Analysis of True-Up Mechanisms and Balancing Accounts."

Public Service Commission of Wisconsin, Docket 4220-UR-108, Northern States Power Company (Wisconsin) Rate Case, 1995, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-UM-100/4220-UM-101, Wisconsin Electric Power Company/Northern States Power Company Merger Case, 1996, "Market Power Remedies; State/Federal Jurisdictional Issues."

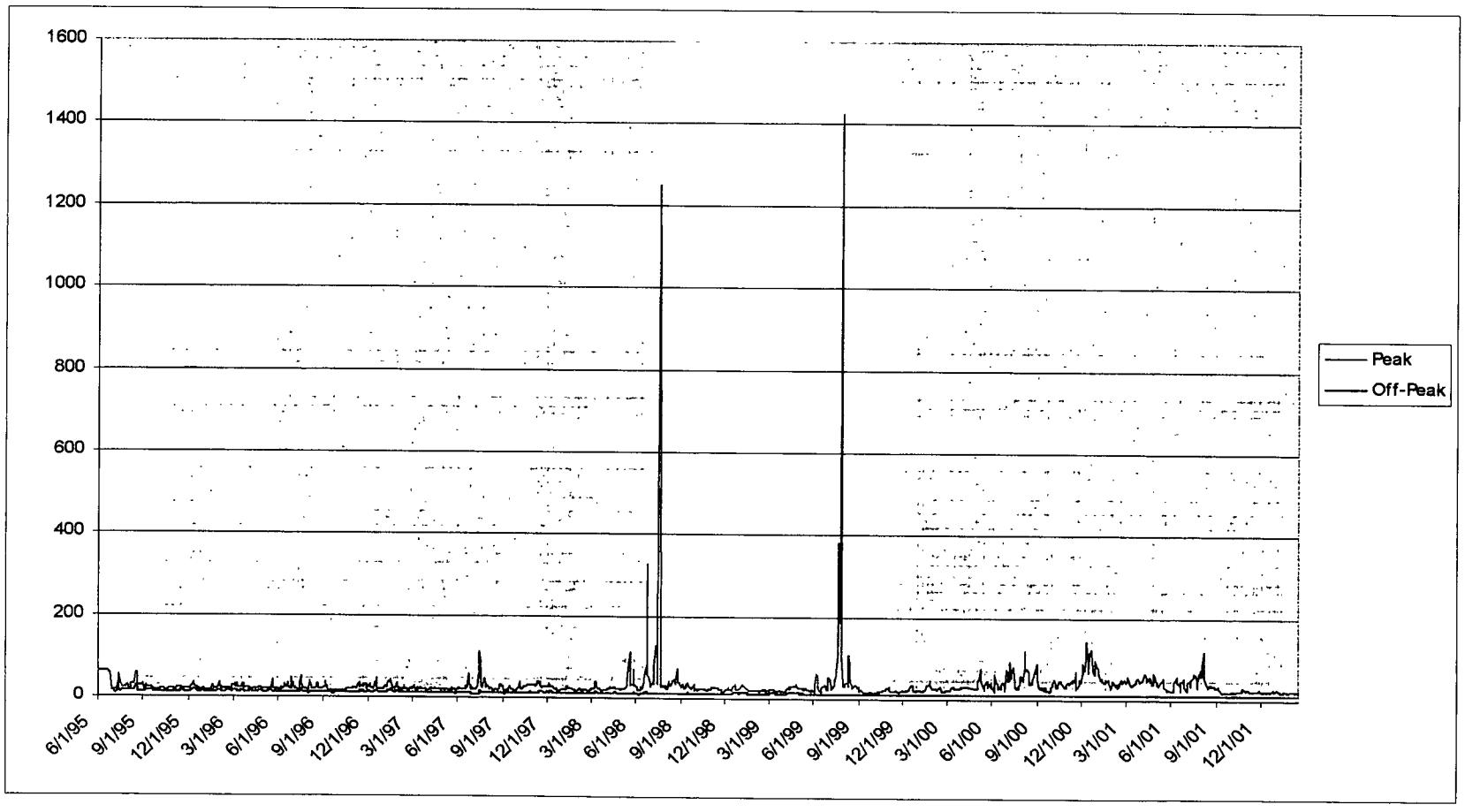
Public Service Commission of Wisconsin, Docket 05-EP-7, Advance Plan 7, 1996, "Risk-Adjusted Discount Rates."

Public Service Commission of Wisconsin, Docket 6680-UM-100, WPL Holdings/IES Industries/Interstate Power Merger Case, 1997, "Market Power Remedies; State/Federal Jurisdictional Issues."

Public Service Commission of Wisconsin, Docket 6630-UR-110, Wisconsin Electric Power Company Rate Case, 1997, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 05-EP-8, Advance Plan 8, 1997, "Purchased Power Costs, Supply Planning Risks and Supply Planning Parameters."

Figure 1
Daily On-Peak and Off-Peak Electricity Prices
MAPP Region



Source: Bloomberg

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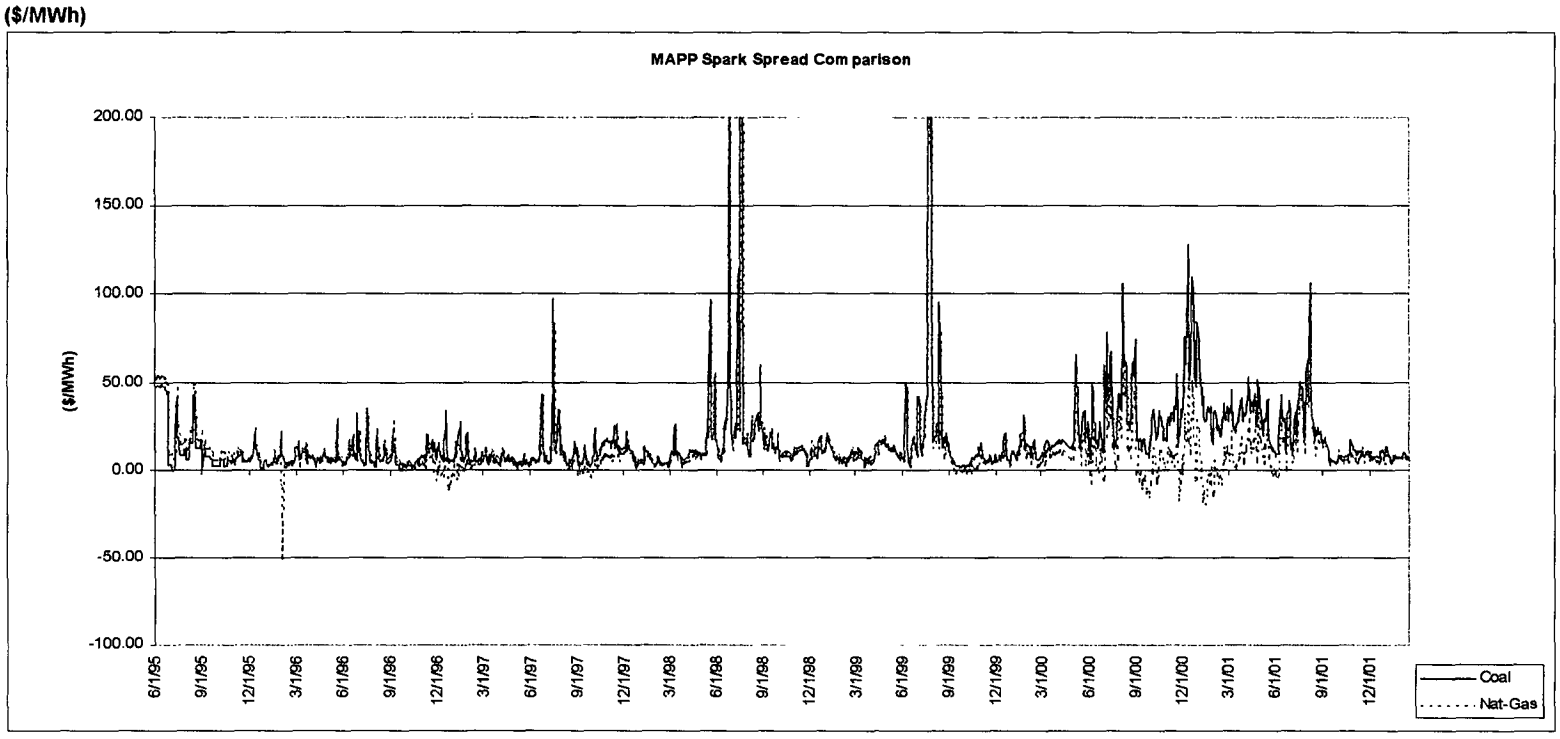
Figure 1
Daily Coal and Natural Gas Based Spark-Spreads
MAPP Region
($/MWh)



Key Assumptions:
- 8,800 BTU/lb coal
- Natural gas cost = spot price for gas at Northern Natural, Ventura
- Coal Cost =weighted average cost of coal for existing MDU contracts (publicly available)
- Coal plant heat rate = 12,000 BTU/kWh
- Gas plant heat rate = 7,000 BTU/kWh

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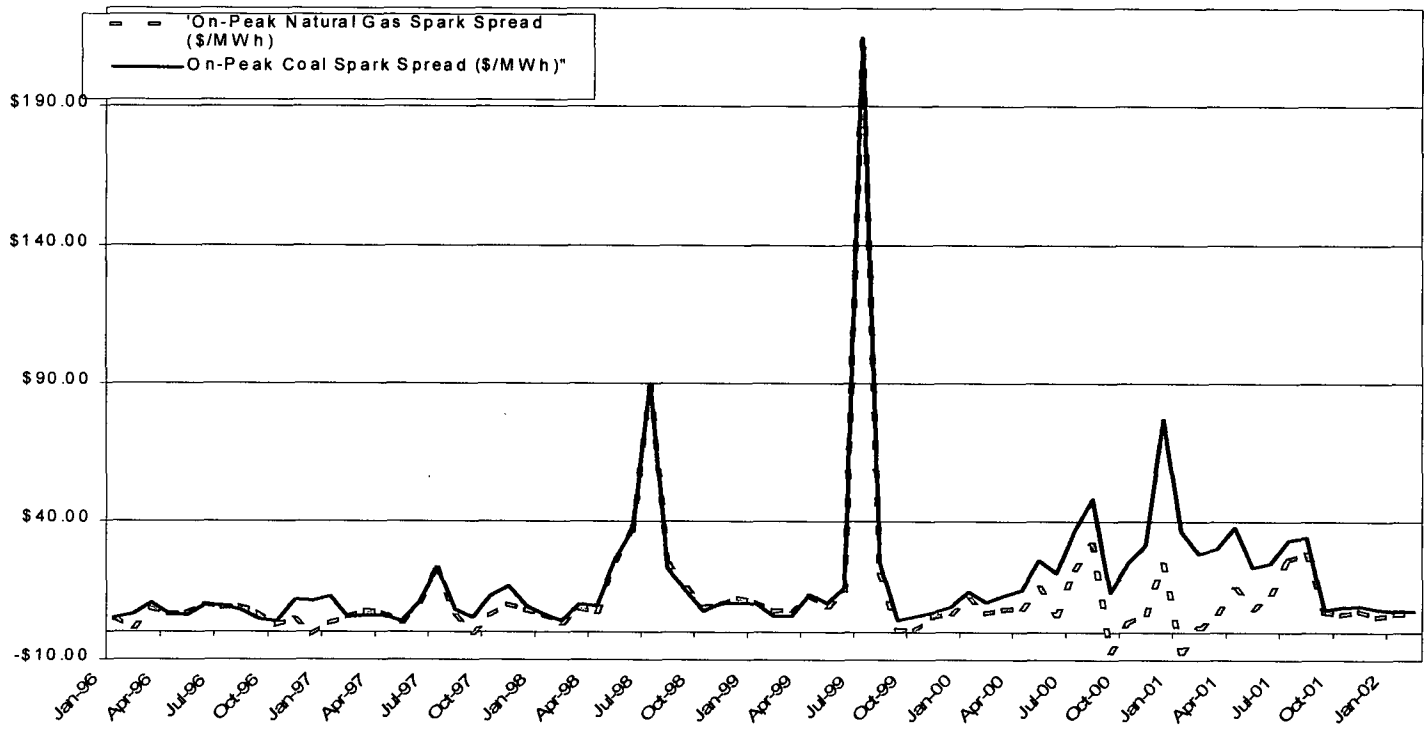
Figure 1
Monthly Coal and Natural Gas Based Spark-Spreads
MAPP Region - Jan. 1996 - Feb. 2002
($/MWh)



Key Assumptions:
•8,800 BTU/lb coal
•Natural gas cost = spot price for gas at Northern Natural, Ventura
•Coal Cost =weighted average cost of coal for existing MDU contracts (publicly available)
•Coal plant heat rate = 12,000 BTU/kWh
•Gas plant heat rate = 7,000 BTU/kWh

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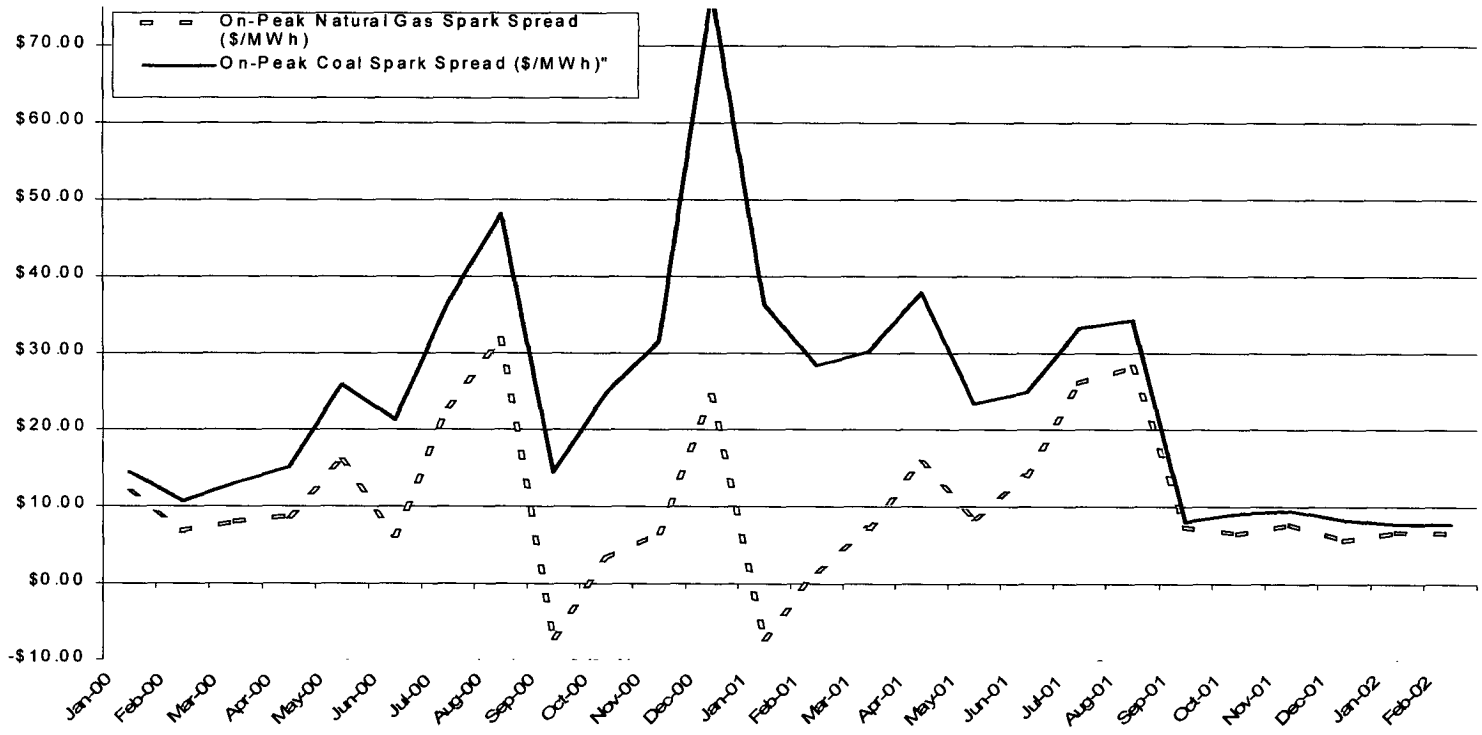
Figure 1
Monthly Coal and Natural Gas Based Spark-Spreads
MAPP Region - Jan. 2000 - Feb. 2002
($/MWh)



Key Assumptions:
•8,800 BTU/lb coal
•Natural gas cost = spot price for gas at Northern Natural, Ventura
•Coal Cost =weighted average cost of coal for existing MDU contracts (publicly available)
•Coal plant heat rate = 12,000 BTU/kWh
•Gas plant heat rate = 7,000 BTU/kWh

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Table 1
Estimated Supply/Demand Balances in MDU Wholesale Markets

	1997	1998	1999	2000	2001	2002
MAPP						
Net Internal Demand	30,050	31,238	32,799	32,671	31,653	32,018
Total Resources	37,900	38,171	39,006	38,821	39,268	40,400
Reserve Margin	26.1%	22.2%	18.9%	18.8%	24.1%	26.2%
MAIN						
Net Internal Demand	46,121	48,653	52,192	51,195	53,415	54,305
Total Resources	55,348	55,554	57,079	59,368	63,923	68,263
Reserve Margin	20.0%	14.2%	9.4%	16.0%	19.7%	25.7%
SPP						
Net Internal Demand	35,538	36,706	37,168	38,671	39,520	40,352
Total Resources	43,811	42,964	42,475	43,286	45,999	48,541
Reserve Margin	23.3%	17.0%	14.3%	11.9%	16.4%	20.3%

Source: Henwood Energy EMSS Database

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
Of
Paul L. Wilkinson

Q. Would you please state your name?

A. My name is Paul L. Wilkinson.

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

A. I am employed as Vice President, Policy Analysis at the American Gas Association (AGA). I have been an AGA Vice President since January 1995 and employed by AGA since June, 1980. I am responsible for all analytical activities at AGA. These activities include energy markets in general and natural gas markets in particular. Including issues related to energy supply, energy demand, energy price, energy data and information collection and dissemination. I have also been heavily involved in environmental issues that affect energy markets. In all of these areas I have conducted research and prepared published analyses either directly, or by supervision of AGA employees or contractors.

Q. Briefly describe your educational background and professional experience.

A. I hold a Bachelors degree in economics from the Univ. of Maryland (1972) and a Masters in economics from the Catholic University of America (1978). I also completed numerous graduate-level courses in

EXHIBIT
1
2/25/02

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Surrebuttal Testimony of Paul L. Wilkinson
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
02/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

economics, energy and the environment at Georgetown University and George Washington University between 1974 and 1977.

Q. On whose behalf are you testifying in this Cause?

A. I am testifying on behalf of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

Q. What is the purpose of your testimony?

A. I will be addressing natural gas market conditions in the 1990's and during the 2000-2001 winter season as well as future market conditions.

Q. Can you describe the natural gas market conditions during the winter of 2000-2001?

A. The natural gas market was extremely tight during the winter of 2000-2001. Demand had increased significantly in 2000 and gas production capability had trouble keeping up with the demand increase. As a result of this pressure on gas supplies, prices increased substantially. In fact, as reflected on Exhibit PLW-1 attached to my testimony, the gas price (NYMEX at the Henry Hub) hit $10 per MMBtu, by far the highest level in a decade. All classes of consumers – residential, commercial, industrial and electric utilities – paid far more for gas than in recent years. This was true in all parts of the country.

Q. How did these conditions compare with previous winter periods during the 1990's?

A. Most of the 1990's can be characterized by the term "surplus deliverability". That is, the decade of the 1990's was, in general, one in

which the ability to produce and deliver gas exceeded the demand for that gas. As a result, wellhead gas prices remained in a fairly narrow range, with an "equilibrium" price of $2.00 per MMBtu for most of the 1990's. In fact, when adjusted for inflation, gas prices in the 1990's were about one-third less than in the mid-1980's. The early portion of the winters in the 1990's (November-December) tended to show some upward price movement. However, this upward movement was, in general, rather modest and it tended to fall back quickly in the later winter periods.

Q. Were there any price "spikes" during the 1990's comparable to the one we saw during the winter of 2000-2001?

A. No. The NYMEX price of gas at the Henry Hub hit $10 per MMBtu in December of 2000. This was twice as high as any spike in the prior 10 years. There were relatively modest spikes in December of 1996 and October of 1997 when the price of gas hit $4.57 per MMBtu and $3.80 per MMBtu. However, in both cases prices retreated to about $2 per MMBtu fairly quickly. In general, the price of gas fluctuated in a relatively narrow price band around $2 per MMBtu for the decade of the 1990's.

Q. How could a more normal weather pattern have affected prices during the 2000-2001 winter?

A. Prices were in the mid-$4 to mid-$5 range for most of the 2000 summer. They had a temporary peak at $5.54 on October 13, but then fell off to $4.48 by October 30. I believe that if we had seen normal or warmer than normal weather in November and December instead of extreme cold,

the price would have shot downward from the $4.48 level instead of rocketing upward.

Q. To what do you attribute the market conditions during the winter of 2000-2001?

A. The market conditions during the winter of 2000-2001 were attributable to supply factors, demand factors, and what I will call "market factors". These individual factors combined in an unusual pattern to put extreme upward pressure on gas prices.

On the supply side, the critical factor was a serious decline in drilling for gas. We like to see the number of gas rigs operating nationally at 600 to 800 rigs or more. For most of 1998 we were at the lower end of this range. However, in the spring and summer of 1999 there was a severe reduction in the number of gas rigs operating as a result of low wellhead gas prices. The number of operating rigs fell off to the 300 to 400 range. The impact of this drilling decline was masked in 1999 due to extremely mild weather that moderated gas demand. However, when demand surged in 2000 it was clear that production capability had fallen to a critical level.

A second factor on the supply side was the amount of gas held in storage. Gas withdrawn from underground storage satisfies about 18 percent of gas demand during the heating season. The volume of gas in storage was at a relatively normal level in the spring of 2000. However, gas prices began to rise in the summer of 2000 and some storage

operators reduced their storage injections in an expectation that prices would begin to fall off. Also, the demand for gas for electricity generation was increasing in response to a hot summer, reducing the volume of gas available for storage. As a result, storage volumes in the late summer and early fall were running 8 to 10 percent behind normal (based on the 5 year average) and this deficit approached 30 percent by the end of the year due to extremely heavy early winter storage withdrawals.

The key variable on the demand side was the weather. The summer of 2000 was significantly warmer than normal, increasing the demand for air conditioning and thus the demand for electricity. Gas is being used increasingly for electricity generation due to both economic and environmental factors. The hot summer was followed by a very cold early winter. Energy demand switched from air conditioning to heating as we moved into the coldest November-December period on record.
An often-overlooked demand factor is economic activity. The economy was very strong for most of 2000 with an annual GDP growth rate of 4.8% in the first quarter and 5.6% in the second quarter. This strong economic activity translated into strong gas demand to fuel factories and commercial establishments throughout the country.

Normally the relatively high gas prices that were experienced in mid-2000 would have resulted in fuel switching from gas to oil in large industrial establishments with dual-fuel capability. These large facilities switch back and forth between gas and oil depending on the relative fuel

prices thereby offering a price relief valve when prices increase. However, oil prices had roughly tripled from their levels about 18 months previously and this relief valve was effectively eliminated.

Finally, in addition to the supply and demand fundamentals, there was a market factor that further exacerbated the high prices of 2000-2001. The gas market is a "real-time" market traded on the NYMEX in a very robust fashion. There is very limited real-time information regarding gas supply or demand available on a real time basis. Thus, it tends to move on the basis of incomplete information and speculation. That real-time information that is available tends to be overemphasized – gas storage information, weather information, and storm activity in the Gulf of Mexico. As indicated above, the gas market in 2000 became very tight and supply was struggling to keep pace with demand. Speculation and overreaction to incomplete market information at a time when the market was very tight resulted in significant price volatility.

Q. To what extent was weather a contributing factor to the market conditions during the winter of 2000-2001?

A. Weather was a critical factor. In fact, it was the most important factor on the demand side of the gas market equation. It was important both in the summer of 2000 and in the winter of 2000-2001. The summer was warmer than normal, which increased the demand for air conditioning, which in turn increased the demand for natural gas to generate electricity. The winter was colder than normal, particularly the early winter, driving up

the demand for gas as a heating source. These increases in demand at a time when markets were already tight and prices were relatively high forced prices even higher.

Q. How warm was the summer of 2000?

A. On a national average basis it was about 7 percent warmer than normal. However, parts of the South and West were 15 to 20 percent warmer than normal. This is key because most of the electricity generation that uses gas is located in the South and West. In addition to pushing up the overall demand for gas, using gas for electricity generation in the summer also diverts gas that otherwise might be injected into storage. When storage levels are lower than normal, as was the case in the summer of 2000, market uncertainty increases and prices tend to move even higher.

Q. How cold was the winter of 2000-2001?

A. The winter of 2000-2001 was extreme by any measure. In particular, the early winter – November and December – was the coldest on record on a national basis. Not only was it cold, but it was extremely cold, it was cold early, and it was cold everywhere. Oklahoma, Arkansas and Missouri had the coldest November-December on record. Across the country, the last two weeks of November were 36 percent and 33 percent colder than normal, respectively. Further, it was colder than normal in all 10 geographic regions during these two weeks. Such uniform cold is very

unusual. Although temperatures moderated in January and February the damage with respect to gas prices was already done.

Q. Were these general market conditions isolated in specific geographic areas?

A. No, the natural gas market is, in essence, a national market. The tight market and the high prices were experienced in all parts of the country. Consumers buying gas are essentially paying for two things – the cost of the gas commodity and the cost of delivering that gas to them. The cost of the gas commodity went up dramatically in 2000-2001, irrespective of where that gas was consumed. The cost of gas delivery is a function of distance and various operational factors, and it therefore does vary by location. However, delivery charges are regulated and they did not fluctuate in 2000-2001 as did commodity charges.

Q. Have you or other employees of the American Gas Association addressed the market conditions of the 2000-2001 winter in the service territories of other local gas utilities?

A. Yes, this is a national issue and we have addressed it in various forums all over the country. We have spoken to legislators, regulators, media and customer groups from Louisiana to New York to Washington and California. The problem was universal and it was extreme.

Q. What is your outlook for the near-term natural gas market?

A. First, let me say that AGA does not perform short-term price projections for anti-trust reasons. However, I can comment on some of

the factors that affect gas prices. The retreat in gas prices following the 2000-2001 winter was as dramatic as their rise. Prices have been in the low $2.00 range for several months now. We have moved from a situation of high demand and low supply to one of low demand and high supply. This situation is expected to continue in 2002.

On the demand side, the economy remains sluggish and expectations are that this will continue for most of the year. In addition, weather has been very mild and the long-term forecast of the National Oceanic and Atmospheric Administration (NOAA) suggests that heating and cooling demand in 2002 will be normal or less than normal. The volume of gas in storage, one barometer of the supply situation, remains at a very high level. As of February 8, 2002 there was 43 percent more gas in storage than the prior 5 year average. Given the economy and weather conditions this surplus is expected to carry into the 2002-2003 winter season thus continuing downward pressure on gas prices.

Q. Do you believe others share your view on near-term market conditions?

A. Yes I do. The *Short-Term Energy Outlook* of the US Energy Information Administration (EIA) projects that wellhead gas prices will be less than $2.00 per thousand cubic feet for the 2nd, 3rd, and 4th quarters of 2002, and that they will range from $2.24 to $2.76 for 2003. Similarly, future gas prices on the NYMEX are in the high $2 to low $3 range for all of 2002 and 2003. These prices are in sharp contrast to the $10 peak we saw last winter.

Q. How about natural gas prices in the longer term?

A. Going out to 2010 I expect prices to remain generally below $4.00. Between 2004 and 2010 I expect prices to move within a band of $2.00 to $4.00, although temporary movements outside this band are certainly possible.

Q. And do other experts share this view as well?

A. I would say, in general, yes. While there is certainly no unanimity in long-term energy price projections, the *Long-Term Outlook* of the EIA projects wellhead gas prices of $3.65 per thousand cubic feet in 2010. We can also look at NYMEX prices and see that they do not exceed $3.75 going out to December of 2007 (prices are not available beyond this point in time).

Q. Does this mean that natural gas market conditions in the future can't repeat the 2000-2001 experience?

A. The prices we saw in the winter of 2000-2001 were extreme and attributable to a number of factors that all came together at once as I previously mentioned. Some refer to last winter as a "perfect storm" scenario. A reoccurrence is certainly not impossible, but it is unlikely and I would certainly not use last winter as a baseline nor would I suggest that last winter was in any way normal or representative of likely future market conditions.

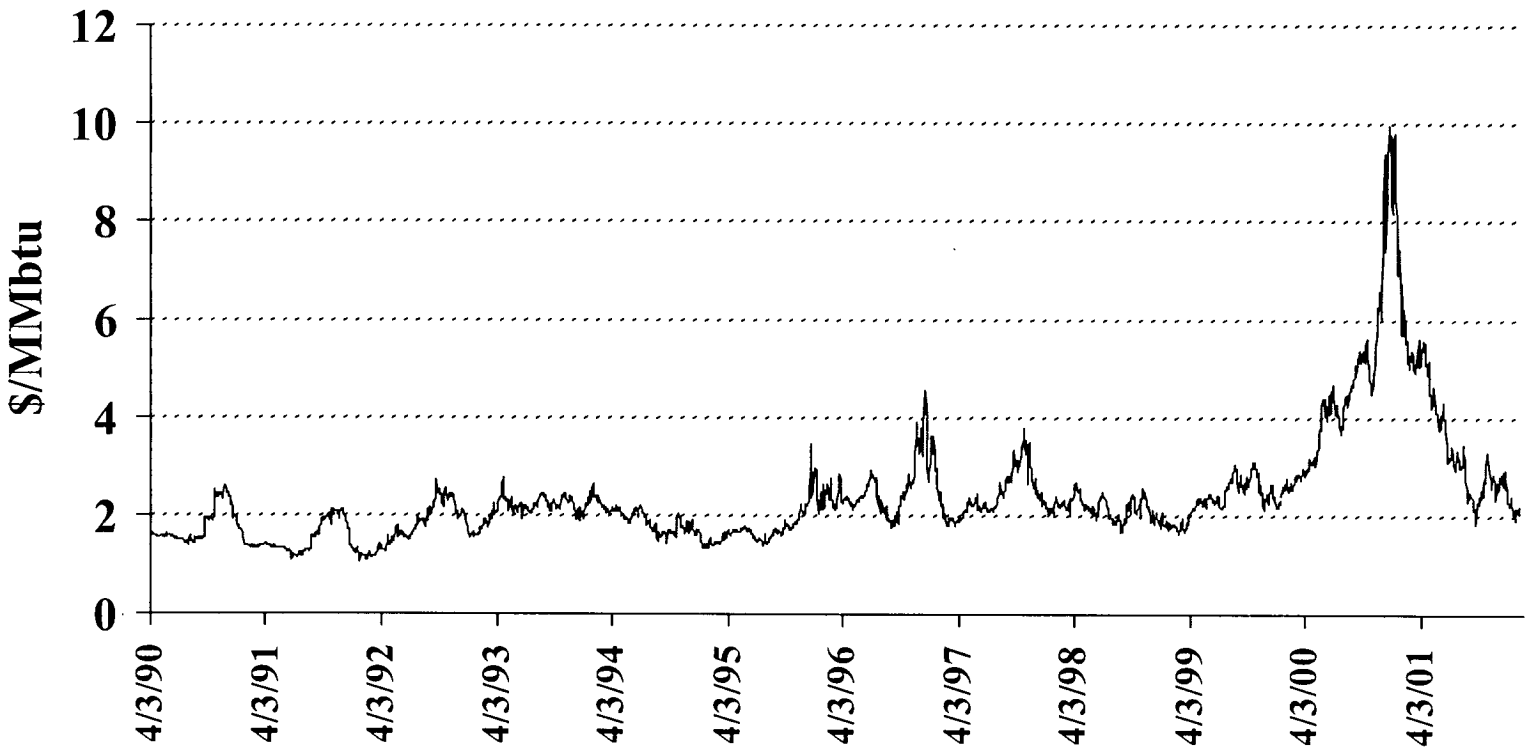
Q. Mr. Wilkinson, does this conclude your testimony?

A. Yes.

Exhibit PLW-1: Natural Gas Prices

NYMEX Henry Hub Futures Daily Settlement Prices

April/90-Jan/02



AGA
American Gas Association

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
of
Terry L. Blinsky

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

A. Yes. My name is Terry L. Blinsky and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Electric Bulk Power Marketing Coordinator for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Terry L. Blinsky who provided direct testimony in this proceeding?

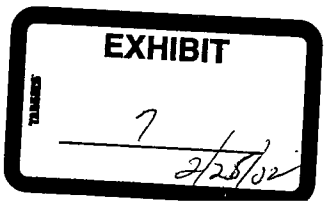
A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to address concerns I have with the rebuttal testimony of Staff witness Mike Diller as it relates to the area of wholesale sales.

Q. What concerns do you have with Mr. Diller's rebuttal testimony?

A. My concerns with his rebuttal testimony relate to his comments on the correlation between gas prices and wholesale electric prices, his characterization of off-peak sales margins and prices and his reliance on actual historic levels in light of the known changes and circumstances in the current wholesale market.



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Surrebuttal Testimony of Terry L Blinsky
by Montana-Dakota Utilities Co., a Division of MDU Re
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Q. Would you please describe your concerns regarding the correlation between gas prices and sales for resale margins?

A. Yes. At page 9, lines 16 to 24, Mr. Diller discusses this point and concludes that natural gas prices declined throughout 2001 yet sales for resale margins did not decline correspondingly. We know that natural gas prices declined during 2001 and we know that our actual sales for resale margins in 2001 did not decline with the gas price decline. However, Mr. Diller has not recognized the cause for this lack of correlation in 2001.

Very simply, the reason that sales for resale margins remained up in 2001 was that Montana-Dakota was successful in entering into a contract with a buyer in March 2001 that covered the summer season of 2001. At the time the contract was executed, prices of gas and electricity were still relatively high and the buyer agreed to pay essentially the futures price that existed at the time the contract was executed. Thus, even though electric prices fell during 2001 as did the gas prices, the revenues received by Montana-Dakota were dictated by the contract and the buyer was obligated to pay the contract prices rather than current prices at the time of delivery. Absent this contractual arrangement, Montana-Dakota would not have been able to retain the margins it did in 2001.

To illustrate this point I have prepared Exhibit No. ____(TLB –4). The exhibit shows the futures prices that existed at various times for purchases in July and August 2001. At the time the contract was executed in March 2001, the futures price for July and August was $126.00 per MW. These prices are

representative of the prices that the buyer agreed to when the contract was executed. Had the contract not existed, Montana-Dakota may have been able to sell power on a month to month or day to day basis during the summer but at prices current at the time of sale. For example, Montana-Dakota could have sold power in late June at about the July futures price that existed at that time, about $46.75 per MW rather than the contract price of $142.50 per MW. Similarly, such transactions could have occurred for August as well, but at prices substantially lower than the contract price.

In summary, there is a direct correlation between gas prices and wholesale power prices but that correlation was not evident because of the contract provisions that Montana-Dakota had in place in 2001.

Q. Does Montana-Dakota have any contracts for the sale of power in place currently or for the upcoming summer season?

A. No.

Q. What are your concerns with Mr. Diller's characterization of off-peak margins and prices?

A. At page 10, lines 20 to 25 of his rebuttal testimony Mr. Diller states that Montana-Dakota estimates that off-peak sales comprise about 47% of the total sales and are priced below the cost of fuel. This statement is not correct. First, the peak and off-peak sales megawatts are not estimates, they represent the actual levels of peak and off-peak sales levels that occurred. Second, the off-peak sales are not priced below fuel costs. Montana-Dakota keeps specific records of peak and off-peak sales for megawatts by time

period. However, the fuel costs shown on the exhibit are the actual fuel costs on an average basis for the month as Montana-Dakota does not keep a specific record of the actual fuel costs by peak and off-peak periods. When energy is sold in the off-peak periods it is typically sold from a specific unit and Montana-Dakota knows what the incremental fuel cost of that particular unit is at the time of the sale. It is not our common practice to sell below the incremental fuel cost of the unit. The resulting total margin shown on my Exhibit No. ____(TLB-3) is correct. If specific records had been kept for peak and off-peak fuel costs, we would find that the peak fuel costs would be above the average and the off-peak fuel costs would be below the average. As this information was not available, the actual fuel costs on an average basis were used.

Q. Would you please describe your concern with the reliance on historical information in light of the known changes and circumstances in the wholesale market?

A. Yes. As I explained in my direct testimony, the wholesale market environment has drastically changed and our opportunities to make higher wholesale sales margins no longer exist. Reliance on the historic actual results in this case will significantly overstate the margins that Montana-Dakota can expect to make in the future. For example, actual January 2002 wholesale sales were 92,964 Mwh and brought a total margin of $622,000. Actual January 2001 wholesale sales were 83,940 Mwh with an actual margin of $1,316,000. Even though we sold more Mwh in January 2002, the margin

was lower by over 50%. This is reflective of the drop in prices. Similar results can be seen for February 2002 as compared to February 2001.

Q. Have you updated your Exhibit No. ___(TLB-3) to reflect changes since the time you prepared it?

A. Yes. I have. The updated information is shown on Exhibit No. ___(TLB-5).

Q. Would you please explain the exhibit?

A. Yes. The Mwh of sales are the actual volumes sold for the eleven month period ending January 2002 plus an estimate for February 2002 based on the actual volumes for the first fourteen days doubled to reflect the full month of 28 days. The projected margins shown in the last column represent the actual for January 2002 and the actual level for the first fourteen days of February 2002 doubled for the full month. The margin for the remaining months was calculated using the Cinergy futures prices for on-peak energy as of February 16, 2002 and off-peak prices which reflect prices currently being obtained for off-peak energy. The resulting total margin that can be expected is $6,429,778. This is about $818,000 less than the expected margin shown on Exhibit No. ___(TLB-3) submitted with my direct testimony. The Mwh of sales are similar but the prices have fallen since preparation of the initial exhibit. This further demonstrates the fact that prices are not rebounding to the levels seen in the last few years. I have shown the February 16, 2002 NYMEX Cinergy Electricity prices on Exhibit No. ___(TLB-6).

Q. Why is it appropriate to rely on the NYMEX futures prices?

A. First, the NYMEX futures represent prices of actual transactions between willing sellers and willing buyers. Second, the Cinergy hub is the hub nearest Montana-Dakota's service area (MAPP region) and is available to all the market participants we typically deal with. These prices are used as a guide by market participants when buying or selling energy. In fact, the current prices that Montana-Dakota has been able to sell on-peak power at very closely align with the March 2002 futures price. I would also note that a recent offer was made to purchase electricity from Montana-Dakota at $35 per megawatt hour for July and August 2002, somewhat below the posted futures price of $38.25 for July and August 2002. Finally, as I described earlier in this testimony, Montana-Dakota was able to obtain a contract for the summer season of 2001 last March that was based on the futures prices in existence at that time.

Q. Would please summarize your position on wholesale sales levels?

A. Yes. Montana-Dakota's ability to make wholesale sales at higher prices peaked in 2001 and will not reoccur in the foreseeable future. It was a market anomaly that allowed us to achieve the higher prices. Currently, there is more supply available than in the past and gas prices are down and expected to stay there, which has the effect of lowering prices for electricity as there are a number of gas fired generators on line and the price differential between coal fired and gas fired generation is now much narrower. These factors are also supported by other witnesses in this proceeding. This means we will not be able to achieve the prices we saw in the last few years. Based

on the latest information available, Montana-Dakota can only expect to achieve wholesale sales margins of $6,429,778 as shown on my Exhibit No.___(TLB-5).

Q. Does this complete your surrebuttal testimony?

A. Yes, it does.

NYMEX FUTURES
CINERGY HUB

Month	Trade Date	Low deal	High deal	
JUL-AUG2001	01/04/01	138.50	138.50	
JUL-AUG2001	02/01/01	141.00	141.00	
JUL-AUG2001	03/13/01	126.00	126.00	1/
JUL-AUG2001	04/02/01	118.50	118.50	
JUL-AUG2001	05/01/01	110.50	110.50	
JUL-AUG2001	05/30/01	78.00	81.00	
JUL2001	06/22/01	45.00	46.75	
JUL2001	07/02/01	23.00	24.50	
AUG2001	08/01/01	49.00	52.00	

1/ Seasonal contract with buyer was signed on March 13.

MONTANA-DAKOTA UTILITIES CO.
POOL SALES CALCULATION

		ACTUAL DATA						2002 PROJECTED			
		On-Peak Sales (Mwh)	Off-Peak Sales (Mwh)	Total Sales (Mwh)	Total Sales Revenue	Margin	Actual Fuel Cost per Mwh	2002 Futures On-Peak Price 1/	2002 Est. Off-Peak Price	2002 Margin Estimate	
Jan-02		47,691	45,273	92,964	$1,644,146	$621,897	$11.00			$621,897	2/
Feb-02	3/			48,328	830,017	319,180	10.57			319,180	3/
Mar-01		52,292	43,693	95,985	2,600,162	1,564,642	10.79	$21.10	$12.00	592,157	
Apr-01		39,727	40,154	79,881	2,193,183	1,335,859	10.73	31.60	12.00	879,898	
May-01		27,343	23,548	50,891	1,345,245	459,452	17.41	24.70	12.50	83,929	
Jun-01		28,866	18,586	47,452	2,088,900	1,396,597	14.59	30.00	12.50	406,002	
Jul-01		32,476	26,985	59,461	3,582,253	2,640,279	15.84	38.25	13.00	651,038	
Aug-01		37,571	29,082	66,653	4,066,038	2,969,765	16.45	38.25	13.00	718,883	
Sep-01		37,593	36,413	74,006	1,437,175	644,063	10.72	22.90	12.50	522,930	
Oct-01		44,942	35,572	80,514	1,575,604	591,734	12.22	22.90	12.00	472,165	
Nov-01		46,911	33,155	80,066	1,530,192	639,113	11.13	22.90	12.00	581,043	
Dec-01		42,721	42,517	85,238	1,556,362	648,503	10.65	22.90	12.00	580,656	
Total		438,133	374,978	861,439	$24,449,278	$13,831,083				**$6,429,778**	

1/ Based on 2002 Futures On-Peak prices at of February 16, 2002.
2/ Actual for January 2002
3/ Actual for February 1st through February 14th, times two to reflect full month.

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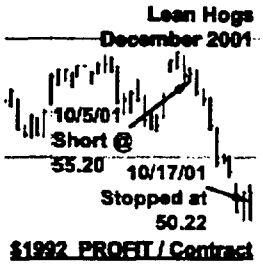

New York Mercantile Exchange (NYMEX)
Energy
Cinergy Electricity (CN)

Market		Open	High	Low	Last	Change	Time
CNH2	Mar 2002				21.10	0.00	settle 4:28PM
CNJ2	Apr 2002				31.60	0.00	settle 4:28PM
CNK2	May 2002				24.70	0.00	settle 4:28PM
CNM2	Jun 2002				30.00	0.00	settle 4:28PM
CNN2	Jul 2002				38.25	0.00	settle 4:28PM
CNQ2	Aug 2002				38.25	0.00	settle 4:28PM
CNU2	Sep 2002				22.90	0.00	settle 4:28PM
CNV2	Oct 2002				22.90	0.00	settle 4:28PM
CNX2	Nov 2002				22.90	0.00	settle 4:28PM
CNZ2	Dec 2002				22.90	0.00	settle 4:28PM
CNF3	Jan 2003				25.90	0.00	settle 4:28PM
CNG3	Feb 2003				25.90	0.00	settle 4:28PM
CNH3	Mar 2003				24.50	0.00	settle 4:28PM
CNJ3	Apr 2003				24.50	0.00	settle 4:28PM
CNK3	May 2003				26.50	0.00	settle 4:28PM
CNM3	Jun 2003				32.00	0.00	settle 4:28PM
CNN3	Jul 2003				39.25	0.00	settle 4:28PM
CNQ3	Aug 2003				39.25	0.00	settle 4:28PM
CNC2	Access Mar 2002				21.10	0.00	settle 1:13PM
CND2	Access Apr 2002				31.60	0.00	settle 1:13PM
CNE2	Access May 2002				24.70	0.00	settle 1:13PM
CNI2	Access Jun 2002				30.00	0.00	settle 1:13PM
CNL2	Access Jul 2002				38.25	0.00	settle 1:13PM
CNO2	Access Aug 2002				38.25	0.00	settle 1:13PM
CNP2	Access Sep 2002				22.90	0.00	settle 1:14PM
CNR2	Access Oct 2002				22.90	0.00	settle 1:14PM
CNS2	Access Nov 2002				22.90	0.00	settle 1:14PM
CNT2	Access Dec 2002				22.90	0.00	settle 1:14PM
CNA3	Access Jan 2003				25.90	0.00	settle 1:14PM
CNB3	Access Feb 2003				25.90	0.00	settle 1:14PM
CNC3	Access Mar 2003				24.50	0.00	settle 1:14PM
CND3	Access Apr 2003				24.50	0.00	settle 1:14PM
CNE3	Access May 2003				26.50	0.00	settle 1:14PM
CNI3	Access Jun 2003				32.00	0.00	settle 1:14PM
CNL3	Access Jul 2003				39.25	0.00	settle 1:14PM
CNO3	Access Aug 2003				39.25	0.00	settle 1:14PM

All quotes are exchange delayed.
For charts, options, and latest headline news, click on the market name.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
of
Richard A. Espeland

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

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

Q. What is your position?

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

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

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

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

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

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Surrebuttal Testimony of Richard A Espeland
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 7
02/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Upon graduating from college, I spent four years in the U.S. Army. Prior to my employment with MDU Resources I was employed by the City of Grand Forks, the State of North Dakota and North American Coal Corporation, all in the human resources area.

In December 1989, I joined MDU Resources as Human Resource Manager, retaining that position until August 2000 when I was elected Vice President—Human Resources.

I am a member of the Society for Human Resource Management and the Central Dakota Human Resource Association. I have spoken on retirement and employee benefit issues on many occasions at national conferences in Boston, Orlando, Chicago and San Francisco.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Rebuttal Testimony of Mr. Mike Diller of the Commission Staff in this case concerning the Supplemental Income Security Plan (SISP) and to further explain the purpose of SISP as originally addressed by Mr. Donald R. Ball of Montana-Dakota in his Direct Testimony.

Q. What are your duties and responsibilities relative to the SISP?

A. I am the Plan Administrator assigned the responsibility by the Board of Directors for the management of the plan, plan design, eligibility, interpretation, communication and benefits administration.

Q. At page 16, line 7 of his testimony, Mr. Diller mentions that the SISP has been in effect since 1982 but that Montana-Dakota has not previously sought rate recovery. Would you please explain why?

A. Yes. When the SISP was implemented in 1982, it was a visionary plan that was new to the utility industry. It was not common at that time anywhere within the industry. In the intervening years since then, and particularly in the last few years, Supplemental Employee Retirement Plans (SERPs) like Montana-Dakota's SISP have become common practice in utilities and related companies. These types of plans have become necessary due to various changes in federal regulations, social security benefits, and employment practices. Those changes have adversely affected Montana-Dakota's key employees as to potential retirement benefits. Because of those changes, SERPs such as Montana-Dakota's SISP have become necessary in order to attract, retain, and provide equitable benefits for key employees. The SISP costs therefore should be included in Montana-Dakota's rates.

Q. Please describe the various changes in federal regulations that have adversely affected retirement plans for key employees.

A. In the early 1980s, defined benefit pension plans could provide benefits in consideration of up to $225,000 in salary. That limit was reduced in the mid 1980s to $150,000 maximum covered compensation, therefore, reducing the benefit eligibility and pension benefits provided by one-third. This compensation limit has slowly increased to the current $200,000 level, but certainly not at a pace equal to general wage inflation. In addition, the 401(k) Plan regulations limit the employee contribution to $11,000. (The effect is the employee with $50,000 in annual income can

contribute 22% of salary while senior executives are generally limited to 10% or less of salary).

Q. What changes in social security benefits have adversely affected key employees?

A. The social security covered wage base, while increasing over the years, has not kept pace with general wage inflation and benefits provided to higher income levels are significantly less than at lower income levels.

Q. At page 16, line 12 of his testimony, Mr. Diller notes that Montana-Dakota participants in the SISP have declined from 38 participants in 1996 to 27 participants in 2001. He suggests that this reduction may indicate that Montana-Dakota no longer sees the same need for this plan. Is there a reason for the decline in SISP participants?

A. Yes. Montana-Dakota has taken aggressive action since 1995 to reduce costs, streamline the organization, and provide the lowest cost to the consumer. As a result of these actions, Montana-Dakota was able to reduce the number of management positions within the Company and thus reduce the number of SISP participants.

Q. Who are the "key employees" you refer to who are participants in SISP?

A. "Key employees" are officers, directors and senior managers of MDU Resources and Montana-Dakota who have the vision to adequately plan for the future, implement appropriate strategies for the Company and to see how to reduce costs, streamline the organization, and implement new technologies to maintain and increase the efficiencies of the Company with fewer employees while keeping the rates stable and

competitive in the industry. A perfect example is the fact that Montana-Dakota has not had to seek an electric rate increase in the last 15 years.

Q. Mr. Diller at page 16, line 19 of his rebuttal testimony expresses concern that there is a lack of symmetry in the SISP in that an employee making $50,000 per year would receive a lower percentage of annual income than a higher income employee. Would you please explain the difference?

A. Yes. His analysis of benefits is limited in its scope. When compensation and benefit programs are designed and implemented, they must be looked at in the context of total benefits. To put the retirement programs in perspective, I have prepared Exhibit No. ___(RAE-1) which reflects the retirement programs available to employees, including SISP. As you will note from the graph, at the lower income levels, the replacement income through retirement programs is about 80 percent. This includes Social Security, the Defined Benefit Pension Plan, and the Company match to employee contributions under the 401(k) Plan. As you move up the income scale, the percentage of income replaced by retirement plans significantly decreases based on retirement plan design requirements and government limitations on retirement plans. The SISP, as a supplemental plan, has been designed to replace some—but not all—of the income that is not replaced by Social Security, the Defined Benefit Pension Plan, and the 401(k) Plan. At the higher income levels only about 50 percent of the annual income is replaced, compared to 80 percent at the lower income levels.

Q. Does the SISP benefit last as long as the other retirement benefits you've noted?

A. No, it does not. The retirement benefits under SISP are payable over 15 years and not the remaining lifetime of the individual (which currently is about 20 years after retirement). Social Security, the Defined Benefit Pension, and the 401(k) Plan income projections meanwhile cover a retired employee's lifetime.

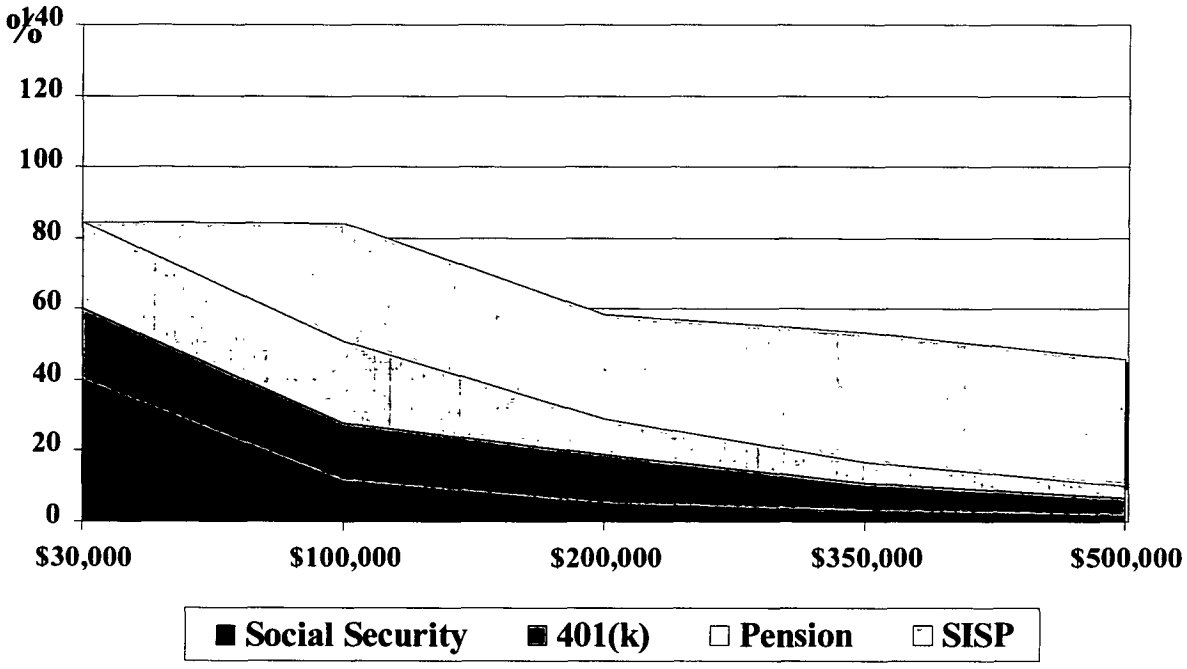
Q. Should Montana-Dakota's SISP be included in rates?

A. Yes, it should be. The SISP is a common type of benefit provided in today's business environment. The combined replacement income from all retirement plans when taken together is equitable, reasonable and justifiable. The SISP recognizes the contributions of key employees whose abilities and vision have enabled Montana-Dakota to streamline operations, reduce costs and employee numbers, implement new technologies and, most importantly to the ratepayer, to keep Montana-Dakota's electric rates at 1987 levels at a time when the consumer price index has risen 59 percent during the same time period.

Q. Does this complete your testimony?

A. Yes, it does.

% Retirement Replacement Income



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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
Of
Donald R. Ball

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

A. Yes. My name is Donald R. Ball and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Director of Regulatory Affairs of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Donald R. Ball who presented direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to address concerns I have with the rebuttal testimony of Staff Witness Mike Diller in the areas of the Mid-Continent Area Power Pool (MAPP) penalty, pension costs, insurance costs and office supplies and expenses.

Q. Would you please explain your concerns with Mr. Diller's treatment of the MAPP penalty costs?

A. Yes. At pages 11 and 12 of his rebuttal testimony Mr. Diller discusses his reasons for not allowing the MAPP penalty costs. He indicates that the Commission should not encourage further penalties in the future by granting

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Surrebuttal Testimony of Donald R Ball
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 7
02/19/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

rate recovery and that the Commission should assume that appropriate reserve margins will be maintained and no additional penalties will be incurred. He eliminates about $458,000 of penalties that were included in the 2001 results.

I would note at the outset that Montana-Dakota, through its extensive planning and forecasting activities, makes every effort to ensure that it has adequate capacity to meet the reserve obligation for serving retail customers. There are a number of employees involved in the process and the latest state-of-the-art tools and techniques are used. The load forecasting process is described in detail in Section 2 of the Integrated Resource Plan filed with the Commission on July 1, 2001. Despite Montana-Dakota's best efforts at forecasting the peak load and resulting reserve obligation, it fell short of capacity to meet the reserve obligation in the summer seasons of 2000 and 2001 due to higher than normal temperatures at the time of the peak and incurred penalties. I should note that the 1999 penalty mentioned by Mr. Diller was for only 0.9 MW, a very small difference.

Application of hindsight indicates that Montana-Dakota should have acquired more capacity during these periods, particularly in 2001, to avoid the penalties. As I explained above, Montana-Dakota makes every effort to assure that it has adequate reserve margin to avoid any penalty. However, with the disallowance of all costs related to the penalty that was incurred and the update to 2001 actual information, the Staff position now has sales levels and expense levels reflective of 2001 results but has no costs included for the

added capacity that was required to achieve those results. This is an obvious mismatch that should be corrected.

The Commission should include, as a proxy for capacity that would have been purchased for the summer of 2001, an amount representative of what the cost would have been for added capacity that would otherwise necessarily have been purchased to avoid the penalty. Montana-Dakota, had it known that it would be deficient in 2001, would have purchased additional capacity for the four months of June, July, August and September 2001 as it is now planning on doing for 2002. However, the precise cost of that capacity is not known. Based on bids received by Montana-Dakota for capacity purchases planned in 2002, the cost for additional capacity is $4,000 per MW month. Using this as a proxy for what would have been purchased in 2001 translates to a cost for the 16.9 MW of $270,000 (16.9 MW times $4,000 times four months). This is the minimum amount that the Commission should include to recognize the cost of the actual capacity used in 2001 to meet the needs of Montana-Dakota's retail customers.

Q. Would you please explain your concerns regarding pension expense?

A. Yes. Mr. Diller denied Montana-Dakota's increase in pension expense for two reasons. First, because there was no actuarial data provided in the discovery process and second, because overall benefits expense decreased by $43,000 from 2000 to 2001. I will address both of those concerns.

When Montana-Dakota was preparing its direct testimony, we looked at current (2002) cost levels versus the cost levels for 2000 as included in Mr.

Diller's cost of service. Where the 2002 level was different from the 2000 level we reviewed the cost to determine the appropriate expense given current information. The benefits account, FERC Account 926 - Employee Benefits, includes pensions, medical and dental insurance, post retirement, 401K, employee discounts and other benefits. The pension account was the only benefit that significantly changed from 2000 to current (2002) levels so that was the only benefit that was adjusted in my direct testimony.

The primary reason for the slight decrease in benefit expense from 2000 to 2001 is because the pension and post retirement amounts were less in 2001 than 2000. But that situation has turned around and those expenses increased and are currently higher than the 2001 level. Montana-Dakota externally funds the pension and post retirement accounts with the annual expense based on an actuarial study performed by Towers Perrin. I should note that the actuarial study is considered confidential information and as such, cannot be provided as a public document. Montana-Dakota, as it has done with such information in the past, will agree to let Mr. Diller review that information on a confidential basis. As explained in my direct testimony, the reason for the increase is because of low investment returns in 2000 and 2001 and a lower discount rate for future years than in the previous studies. These increases for 2002 are real, currently being booked and they are expected to continue to increase through 2006.

To deny recovery of current expenses because the expenses decreased between 2000 and 2001 when current expense levels are

demonstrably higher is not reasonable. Exhibit No.___(DRB-1) shows the 2001 level of expense and the current expense levels that Montana-Dakota is recording on its books for pensions and post-retirement benefits. The amount of the adjustment for pension is $179,000 and the adjustment for post-retirement benefits is $62,000.

I should also note that the amount for the Supplemental Income Security Plan, discussed in the surrebuttal testimony of Mr. Espeland, is $683,000 currently. This reflects an update from the amount contained in my direct testimony.

Q. Would you please explain your concerns with insurance expense?

A. Yes. Mr. Diller proposes to leave insurance expense at the 2001 levels because the 2001 level of expense changed very little from 2000. He also says that he needs additional proof from Montana-Dakota that insurance expenses have increased. Most of Montana-Dakota's insurance policies expire in November or December each year. Therefore, the significant increases in insurance expense as outlined in my direct testimony became effective in late 2001 and therefore are not visible when comparing 2001 expense to 2000 expense. However, the level of expense that we are incurring today is significantly higher than we experienced in 2001. The increase in insurance costs is affecting companies nationwide, not just Montana-Dakota. I have been advised by the Company's Risk Management personnel that the year 2000 and beginning of 2001 were reflective of "soft market" conditions, i.e., expanded coverage at lower prices, and the

insurance costs for those years reflect this. The situation changed in 2001 when the market changed to "hard market" conditions reflective of lower coverage and higher prices. The September 11, 2001 terrorist attack further exacerbated the situation by increasing costs and changing available policy coverages. One example of the change is the All Risk Property Insurance Premium, which went from an annual premium of approximately $377,000 in effect through December 2001 to an annual premium of $550,600 through December 2002, an increase of 46%. These increases are real and the higher premiums are in effect today.

Exhibit No.__(DRB-2) lists each of the insurance policies along with the expiration date of the policy and the current annual expense. As shown on the exhibit, the annual expense being incurred today is 37% higher than the 2001 expense level for insurance. Montana-Dakota's proposed insurance expense adjustment of $155,000 reflects the level being incurred today and is reasonable.

Q. Would you please explain your concerns with Mr. Diller's adjustment to office supplies and expenses?

A. Yes. At pages 18 and 19 of his rebuttal testimony Mr. Diller discusses his adjustment to office supplies and expenses. His adjustment reflects a 5% increase over the 2000 level with a net result of decreasing the actual 2001 result by $678,000. His testimony indicates that he is not aware of what caused the increase and that he made the adjustment to reflect a more normal operating expense level. I take exception to this adjustment because

the items that caused the increase from 2000 to 2001 are not one time aberrations but continuing expenses. Items causing the increase from 2000 to 2001 are the costs for a corporate aircraft which was acquired in 2001, increased service and supply costs for the Company's computer infrastructure, an increase in phone expenses due to expanding cell phone use and improvement of the computer frame relay network, an increase in subcontract work which is continuing and reclassification of subcontract fees and bank service fees from other accounts. The last item simply means that other accounts were reduced to reflect the reclassification. As these items are recurring expenses, the amounts should be included which reflects an increase in expense of $678,000 from the Staff position.

Q. Yes. Does this complete your surrebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PENSION AND POST RETIREMENT EXPENSE
ELECTRIC UTILITY - NORTH DAKOTA
(000S)

	2001	2002 1/	Change
Pension			
Electric Utility	($1,673)	($1,388)	$285
Allocated to North Dakota	(1,051)	(872)	179
Post Retirement			
Electric Utility	$1,062	$1,161	$99
Allocated to North Dakota	669	731	62

1/ January 2002 expense annualized.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF INSURANCE EXPENSE
2002

Type of Insurance	Company	Annual Premium	Expiration
Director's & Officer's Liability Insurance -- 1st Layer	Federal Insurance Company (CHUBB Group)- Aon Risk Services	38,463	10/31/02
Director's & Officer's Liability Insurance -- 2nd Layer	AEGIS - Aon Risk Services	1,816	10/31/02
Director's & Officer's Liability Insurance -- 3rd Layer	Energy Insurance Mutual - Aon Risk Services	30,089	10/31/02
Director's & Officer's Liability Insurance -- 4th Layer	Clarendon	10,403	10/31/02
Fiduciary and Employee Benefits Liability Insurance	Johnson & Higgins	7,873	10/31/02
Public Liability & Property Insurance Damage of Others	AEGIS - J & H Marsh & McLennan	187,495	12/31/02
Public Liability & Property Insurance Damage of Others	Energy Insurance Mutual	9,192	12/31/02
Fire, Extended Coverage Perils, Boiler & Machinery	FM Global	311,157	12/31/02
Blanket Crime	Aon Risk Services	2,635	10/31/02
Special Contingency	Alexander & Alexander	850	5/1/03
Hired and Non-owned Aircraft Liability	J&H Marsh & McLennan, Inc.	1,570	12/31/01
General Liability	Self Insurance	146,545	12/31/01
Aircraft Coverage		$748,088	
Big Stone		59,280	
Coyote		83,662	
		891,030	
	ND Factor - O&M Excl. Fuel, Purch. Pwr & A&G	64.59670%	
	Allocation to North Dakota	$575,576	
	2001 North Dakota expense	420,193	
	Increase	$155,383	36.98%

2/19/2002

Case No. PU-399-01-186
Exhibit No._____(DRB-2)
Page 1 of 1

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Surrebuttal Testimony
of
Rita A. Mulkern

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

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

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

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

Q. Are you the same Rita A. Mulkern who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to quantify the adjustments to the North Dakota Public Service Commission Staff (Staff) rebuttal case discussed by Mr. Gaske, Mr. Mahowald, Mr. Blinsky, Mr. Espeland and Mr. Ball, and the effects of those adjustments on the North Dakota electric revenue requirement. I am sponsoring Exhibit No.___(RAM-3) and Exhibit No. ___(RAM-4) which quantify the effect of these adjustments to the Staff's rebuttal case on the North Dakota electric revenue requirement.

Q. Would you explain Exhibit No. ___(RAM-3)?

A. Yes. The exhibit summarizes the adjustments to the income statement

EXHIBIT
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2-25-02

as supported by the other witnesses. Each of the adjustments was developed either on a total company basis and allocated to North Dakota electric operations or calculated on a North Dakota electric basis.

Q. What does Exhibit No.___(RAM-4) show?

A. Exhibit No. ___(RAM-4), page 1 is a summary showing the income statement and rate of return for 2001, the Staff adjustments and position, Montana-Dakota's adjustments from Exhibit No. ___(RAM-3), and the resulting adjusted income statement, rate of return and revenue deficiency calculation. Page 2 shows similar rate base information.

Q. Why does your exhibit show a Staff revenue excess of $7.135 million rather than the $7.327 in Mr. Diller's rebuttal testimony?

A. The interest expense that is deducted for calculating income taxes should have been restated to reflect Mr. King's proposed debt costs. With the lower interest rate, the interest tax deduction is lower and results in higher income taxes. The income tax adjustment is restated to reflect the higher income taxes.

Q. What effect do the adjustments have on the revenue requirement?

A. As shown on Page 1 under the column labeled "Adjusted", Montana-Dakota's adjusted return on equity is 11.091%, below the 12.75% return on equity required. Montana-Dakota will experience a revenue deficiency of $1,727,000 at a 12.75% return on equity based on the adjusted calendar year 2001 results.

Q. Does that complete your testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO STAFF REBUTTAL CASE
2001 TEST YEAR

	Total Company	North Dakota
Revenue		
Pool Sales		($5,754)
O&M		
Demand Penalty	$270	$186
Pension Expense	285	179
FAS 106	99	62
SISP		683
Insurance		155
Office Expense		405
		$1,670
Income Taxes		($3,078)
Net Adjustments to Income		($4,346)

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF REBUTTAL CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2001 TEST YEAR

	2001	Staff Adjustments	Staff Test Year	Montana-Dakota Adjustments	Adjusted
Operating Revenues:					
Retail	82,472		$82,472		$82,472
Sales for Resale	17,687	(538)	17,149	($5,754)	11,395
Other Operating Revenues	2,768		2,768		2,768
Unbilled Revenue	(825)		(825)		(825)
Total Operating Revenues	$102,102	($538)	$101,564	($5,754)	$95,810
Operating Expenses:					
Fuel & Purch Power	$31,762		$31,762		$31,762
Production Expense	8,909	(951)	7,958	186	8,144
Transmission Expense	3,915	370	4,285		4,285
Distribution Expense	5,010		5,010		5,010
Customer Accounts Expense	2,233		2,233		2,233
Customer Service & Info. Exp.	113		113		113
Sales Expense	281		281		281
Administration & General Exp.	8,968	(414)	8,554	1,484	10,038
Total O&M	61,191	(995)	60,196	1,670	61,866
Depreciation Expense	11,955	77	12,032		12,032
Taxes Other than Income	4,019		4,019		4,019
Current Income Taxes	8,860	266	9,126	(3,078)	6,048
Deferred Income Taxes	(905)		(905)		(905)
Total Operating Expenses	$85,120	($652)	$84,468	($1,408)	$83,060
Net Operating Income	$16,982	$114	$17,096	($4,346)	$12,750
Rate Base	$126,800	$4,204	$131,004	0	$131,004
Average Rate Base			$128,902		$128,902
Rate of Return on Avg. Rate Base			13.26%		9.89%
Less: Weighted Cost of LTD			3.960%		4.230%
Weighted Cost of Pref. Stock			0.240%		0.240%
Weighted Return on Equity			9.060%		5.420%
% of Equity to Capital Structure			48.870%		48.870%
Return on Equity			18.539%		11.091%
Required Return			9.92%		10.700%
Income Requirement			$12,787		$13,793
Pro Forma Net Income			17,096		12,750
Income Deficiency (Excess)			($4,309)		$1,043
Revenue Deficiency (Excess)			($7,135)		$1,727

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF REBUTTAL CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2001 TEST YEAR

	2001	Staff Adjustments	Adjusted	Average Staff Test Year	Montana-Dakota Adjustments	Adjusted
Rate Base:						
Plant in Service	$379,126	$4,325	$383,451	$381,289		$381,289
Less: Accumulated Depreciation	215,094	71	215,165	215,130		215,130
Construct. Work in Prog.	518		518	518		518
Net Plant in Service	$164,550	$4,254	$168,804	$166,677	$0	$166,677
Additions:						
Materials and Supplies	2,909		2,909	$2,909		2,909
Fuel Stocks	1,255		1,255	1,255		1,255
Prepayments	99	15	114	107		107
Total Additions	$4,263	$15	4,278	$4,271	$0	$4,271
Deductions:						
Accum. Deferred Income Taxes	39,774	65	39,839	39,807		39,807
Accumulated Deferred ITC's	2,229		2,229	2,229		2,229
Cust. Advances for Construct.	10		10	10		10
Total Deductions	42,013	65	42,078	42,046	0	42,046
Rate Base	$126,800	$4,204	$131,004	$128,902	$0	$128,902

PU 399-01-186

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Public Service Commission
State of North Dakota

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February 11, 2002

FEB 11 2002
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Jon Mielke, Commission Secretary
Public Service Commission
State Capitol
Bismarck, ND 58505

RE: Staff Investigation of MDU's Electric Earnings
Case No. PU-399-01-186

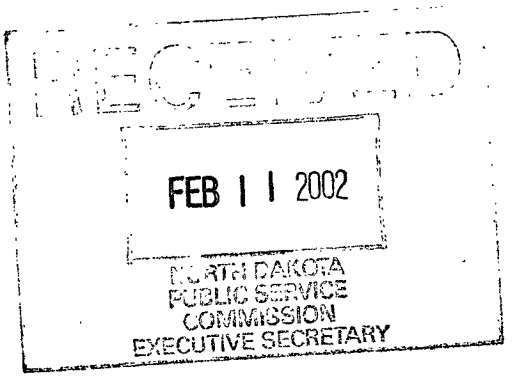
Dear Mr. Mielke,

In accordance with the procedural schedule, the staff's rebuttal testimony is enclosed for the above case.

Sincerely,

Mike Diller
Director of Accounting

55 PU-399-01-186 Pages: 1
Cover letter re Staff's Rebuttal Testimony
by Public Service Commission by Mike Diller
02/11/2002 CC: Comm Legal PUD (3) Mike ALJ .



Rebuttal Testimony

Mike Diller

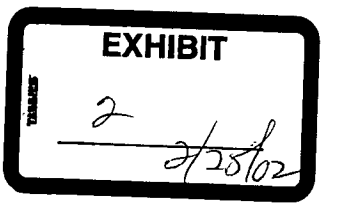
Before the **North Dakota Public Service Commission**

Montana-Dakota Utilities Co.

North Dakota Electric Operations

Case No. PU-399-01-186

Staff Investigation of Excess Earnings



February 2002

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Rebuttal Testimony of Mike Diller

by Public Service Commission by Mike Diller
Exhibit # 2
02/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike

Q: PROVIDE YOUR NAME AND POSITION AT THE PUBLIC SERVICE COMMISSION.

A: My name is Mike Diller and I am the Director of Accounting. I am responsible for the Commission's accounting and data processing operations and any assigned public utility matters.

Q: ARE YOU THE SAME MIKE DILLER THAT PROVIDED DIRECT TESTIMONY IN THIS CASE?

A: Yes, I am.

Q: WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A: The purpose of my testimony is to address the concerns I have with the direct testimony of Montana-Dakota Utilities Co. (MDU) filed January 11, 2002. I will give consideration to the issues raised by MDU and any updated financial information that recently became available for 2001 operating results.

Q: SUMMARIZE THE POSITIONS REPRESENTED IN THIS CASE.

A: The direct testimony of staff argues for an 11% rate reduction to reduce annual revenue collections by $9.155 million. The direct testimony of MDU argues that no rate reduction is necessary.

In developing its direct testimony, staff utilized actual revenues and costs using a 2000 test year. Because of the tremendous growth in sales for resale margins, staff made an adjustment to actual 2000 results for

additional margins occurring during the first 5 months of 2001. Staff did not make any adjustments to reflect expected increases in 2001 costs because of the growth in sales for resale margins. Staff believed that the additional expected margins for 2001 would more than cover any increased operating expenses.

In its direct testimony, MDU argues that things have changed in the sales for resale market and that the increased margins seen in recent years will no longer occur. Instead of total company margins used by staff of $13.667 million, MDU sponsors testimony arguing for $7.247 million in sales for resale margins. MDU's sales for resale margin projection reduces staff's case by $4.266 million when allocated to North Dakota. MDU further argues for the inclusion of lost revenues, increased expenses, higher capital costs and additional investments.

Q: PLEASE SUMMARIZE YOUR REBUTTAL POSITION.

A: After giving consideration to MDU's arguments in direct testimony and new financial information for the year ended 2001, staff has reduced its initial complaint of excess earnings from $9.155 million to $7.327 million.

Q: HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A: I will work through the primary components of rate of return regulation much like I did in my direct testimony. These components include rate base, rate of return and net regulated income.

Rate Base

Q: PLEASE ADDRESS RATE BASE ISSUES BROUGHT FORTH BY MDU'S WITNESSES.

A: In my direct testimony I drew attention to the fact that rate base has been declining since MDU's last rate case. However, in recent years, net plant in service along with overall rate base levels has remained fairly steady. Therefore, staff's overall position to use 2000 rate base levels for establishing rates in this proceeding seemed reasonable at the time.

MDU, through its witnesses Mr. Gress and Mr. Ball, argue that a number of 2002 projects should be included as an adjustment to staff's 2000 rate base. For purposes of this proceeding, staff will yield to the Company's assertion that these costs are above normal capital budget levels and therefore should be added to rate base. However, additional considerations should also be given to the new 2001 financial results. The following table from my direct testimony was updated to include 2001 information.

Description	(CN 10799) TY 1986	1998	1999	2000	2001 1/
	(Thousands)				
Plant in Service	$259,898	$359,461	$366,890	$375,347	$378,437
Accum. Res. for Depreciation	87,017	184,135	193,286	202,071	210,278
Avg. Net Plant in Service	$172,881	$175,326	$173,604	$173,276	$168,159
Constr. Work in Progress		517	2,572	850	684
Materials & Supplies	2,621	3,271	3,252	3,202	2,987
Fuel Stocks	1,457	1,305	1,192	1,277	1,173
Prepayments	413	249	265	209	110
Net Negative Salvage	2,247				
Accum. Def. Income Taxes	(28,253)	(42,366)	(42,124)	(41,564)	(40,437)
Accum. Invest. Tax Credits	(11,092)	(4,105)	(3,583)	(3,074)	(2,521)
Customer Advances	(18)	(8)	(309)	(509)	(264)
Average Rate Base	$140,256	$134,189	$134,869	$133,667	$129,891

1/ Average of beginning of year and end of year balances.

As you can see from the table, net plant in service decreased in 2001. The reduction should therefore be considered along with the extra capital projects for 2002. Therefore, staff recommends that the commission adopt the new rate base levels reported by MDU and include all of the adjustments proposed by MDU in this proceeding, as follows.

Description	Projected 2002 (Thousands) Beginning Balance	MDU Adjustments	Ending Balance	Average Balance
Plant in Service	$379,126	$4,325	$383,451	$381,289
Accum. Res. for Depreciation	215,094	71	215,165	215,130
Avg. Net Plant in Service	$164,032	$4,254	$168,286	$166,159
Constr. Work in Progress	518		518	518
Materials & Supplies	2,909		2,909	2,909
Fuel Stocks	1,255		1,255	1,255
Prepayments	99	15	114	107
Net Negative Salvage			0	-
Accum. Def. Income Taxes	(39,774)	(65)	(39,839)	(39,807)
Accum. Invest. Tax Credits	(2,229)		(2,229)	(2,229)
Customer Advances	(10)		(10)	(10)
Average Rate Base	$126,800	$4,204	$131,004	$128,902

Cost of Capital

Q: WHAT COST OF CAPITAL DOES STAFF RECOMMEND FOR THIS CASE?

A: Staff witness Charlie King is testifying to the appropriate cost of capital. His recommended cost of capital is included here for purposes of calculating MDU's excess revenue position at the end of my testimony.

Description	Capital Ratio	Cost	Weighted Cost
Debt	45.90%	8.62%	3.96%
Preferred Stock	5.23%	4.63%	0.24%
Equity	48.87%	11.70%	5.72%
Total	100.00%		9.92%

Net Regulated Income

Q: PLEASE ADDRESS NET REGULATED INCOME ISSUES BROUGHT FORTH BY MDU'S WITNESSES.

A: As with rate base, the commission should consider the operating results for 2001 when considering MDU's adjustments to bring costs forward. An approach similar to the rate base discussion above is made for net regulated earnings. The following table updates the net regulated income schedule from my direct testimony to include 2001 operating results.

	Thousands				
Description	TY 1986	1998	1999	2000	2001
Residential	$32,003	$32,347	$32,099	$31,916	$33,403
Small Commercial	33,926	17,329	17,170	17,275	17,603
Large Commercial		26,148	26,667	26,840	28,802
Public Street Lighting	1,458	1,456	1,451	1,420	1,450
Sales to Public Authorities	1,334	1,221	1,180	1,141	1,213
Other Operating Revenues		2,669	2,373	2,691	2,768
Unbilled Revenue	1,162	(49)	(283)	646	(824)
Sales for Resale		7,889	13,265	15,034	17,687
Total Revenues	$69,883	$89,010	$93,922	$96,963	$102,102
Production Expense		$35,161	$37,160	$38,365	$40,671
Transmission Expense		3,493	3,667	3,567	3,915
Distribution Expense		4,099	4,586	4,660	5,010
Customer Accounts		2,034	2,162	2,113	2,233
Customer Service & Info.		84	96	105	113
Sales Expense		192	258	269	281
Administration & General		8,602	8,303	8,154	8,968
Total Operating Expenses	$40,654	$53,665	$56,232	$57,233	$61,191
Depreciation	$8,751	$11,206	$11,436	$11,803	$11,955
Taxes Other Than Income	$2,935	$3,832	$3,936	$3,811	$4,019
Income Tax Expense	$4,688	$5,486	$6,319	$6,750	$7,955
Net Regulated Income	$12,855	$14,821	$15,999	$17,366	$16,982

Q: DISCUSS EACH REGULATED NET INCOME ADJUSTMENT RECOMMENDED BY MDU'S WITNESSES.

Sales for Resale

A: The sales for resale margins is the biggest issue in this case. Mr. Blinsky's testimony argues that the sales for resale market has changed and then provides an estimate of the net effect of those changes on future profits. Essentially, Mr. Blinsky argues that the supply and demand characteristics of the marketplace have changed via the downturn of the general economy; lower natural gas prices making it a viable competitor to coal generation again; and new generation facilities are expected to become available.

At the end of his testimony, Mr. Blinsky uses the futures market for projecting margins in 2002. His results indicate that margins will decrease by 55% when compared to 2001 which is equivalent to about the same margins that MDU earned during the summer months of June, July and August of 2001.

I agree with Mr. Blinsky that the concerns he addresses can and do impact the supply and demand of electricity and thereby affect the price of electricity. However, it is difficult to determine to what degree such things will have on future off-system sales or the price of those sales. A fair bit of judgment by the commission will be required to decide this issue.

Q: DO YOU HAVE ANY COMMENTS RELATED TO THE DOWNTURN OF THE GENERAL ECONOMY?

A: Some say the recession is over while others say it hasn't occurred yet. I don't know whom to believe. I'm not sure the financial market as a whole knows which direction the general economy is headed.

Q: DO YOU HAVE ANY COMMENTS RELATED TO THE CORRELATION OF NATURAL GAS PRICES WITH OFF-SYSTEM SALES MARGINS?

A: Staff agrees that natural gas prices can affect the price utilities extract for off-system sales. It seems reasonable that if part of the existing generation facilities are taken out of play that the remaining players could charge more for the same product. To what extent and under what conditions is much more difficult to determine.

Staff acknowledges that there have been times when a correlation between natural gas prices and sales for resale margins appears to exist. At the same time, there are also times when very little correlation exists. For example, natural gas prices peaked at about $9 per Mmbtu in January 2001 and have steadily declined throughout the year. Yet, sales for resale margins ignored the price decline of natural gas and soared to new heights in 2001. The future cost of natural gas is worth considering but not an end all solution to determining future off-system sales margins.

Q: DO YOU HAVE ANY COMMENTS WITH REGARD TO THE ADDITION OF NEW GENERATION FACILITIES?

A: Based on information provided by MDU, as projected by MAPP, it appears that planned additions in the near future will outstrip the projected growth in demand. On the other hand, some believe that the recent events surrounding Enron has tainted the energy market in general, including the independent power producers. The effect of such an event may very well impact the number of generation plants built in the future. Again, the overall impact to off-system sales and margins of these new generation facilities, if built, is not determinable.

Q: WHAT RESERVATIONS DO YOU HAVE WITH MR. BLINSKY'S METHOD OF FORECASTING 2002 MARGINS ON SCHEDULE TLB-3?

A: Staff can agree to the use of actual information for 2001 because sales levels for 2001 have remained relatively unchanged from 1999 and 2000. MDU has sold 943,520,616 kWh, 930,318,472 kWh and 898,178,160 kWh during 1999, 2000 and 2001, respectively. However, staff cannot agree with the use of non-actual assumptions thereafter.

MDU's estimate of 2002 off-system sales margins begins by dividing the total sales into on-peak and off-peak units. MDU estimates that off-peak sales (sales from 10 p.m. until 6 a.m. and all day Sunday) comprise about 47% of the total sales and are priced below the cost of fuel. Such an assumption results in a net loss contribution of $144,319 for 2002. Staff can understand why, on occasion, a company might make off-

system sales at a small loss to avoid shutting down a plant but seriously questions the idea that all off-peak sales throughout a given year would result in a net margin loss.

Staff requested source data for Mr. Blinsky's off-peak prices. MDU replied that off-peak prices are estimates based on recent experience. Without the source data and some historical perspectives, staff is unable to conclude anything from this calculation.

With regard to on-peak sales, MDU calculates expected margins based on futures prices as of January 2, 2002. Staff understands the concept but is concerned with placing too much emphasis on futures prices.

Q: DO YOU HAVE ANY SUGGESTIONS TO HELP THE COMMISSION DECIDE THIS ISSUE?

A: Staff believes that the commission should rely primarily on actual results in making its determination. In recent years, MDU has benefited greatly as the actual sales for resale margins continued to increase. Abandoning actual results now in favor of Mr. Blinsky's projection model seems inappropriate.

Staff filed direct testimony in August 2001 advocating a level of total company margins of $13,667,000 for ratemaking purposes. Since then, actual 2001 results yielded total company margins of $15,937,892. Staff believes that the 2001 actual operating results require no adjustment

other than to eliminate some insurance recoveries applicable to 2000 but recorded in 2001. Therefore, staff proposes to reduce reported margins by $810,841 on a total company basis to eliminate these out-of-period costs. Similar to its direct testimony, staff has updated its sales for resale margins schedule by month through 2001 as Rebuttal Attachment MRD-1.

Q: PLEASE DISCUSS THE REMAINING ISSUES RELATED TO NET REGULATED INCOME.

Demand Penalty

A: Mr. Ball argues for demand penalties assessed by the Mid-American Power Pool (MAPP) for failure to have sufficient reserve capacity to meet its reserve requirement for retail customers. The updated 2001 costs include demand penalties of $375,000 for 2000 and $82,836 for 1999 totaling demand penalties of $457,836. MDU also testifies that it will incur a penalty of about $1,007,000 for 2001 deficiencies.

Staff does not support inclusion of these costs in rates and makes an adjustment to exclude them from 2001 results. The MAPP maintains a reserve margin standard of 15% to protect against unforeseen events and emergencies. MDU has failed to meet the standard 3 years in a row and the penalties have been growing. The commission should not encourage further penalties in the future by granting MDU rate recovery.

Instead, the commission should assume that appropriate margins will be maintained in the future and no additional penalties will be incurred.

MDU recently attended the commission's periodic information exchange (PIE) meeting held February 5, 2002. MDU represented, through its employee Mr. Hoa Nguyen, that penalties for breaching reserve margin requirements are effective regulators. Mr. Nguyen explained that Mid-America Interconnected Network (MAIN) is ineffective in maintaining its reserve margin requirements because it relies on peer pressure rather than on effective financial penalties for noncompliance. Staff contends the same is true here and strenuously opposes any inclusion of penalties in rate recovery. The purpose of a penalty is to attempt to modify behavior. Eliminating the cost of the penalty by assigning the cost to ratepayers will seriously hinder the purpose of the penalty and what it is trying to accomplish.

AVS Major Maintenance

Mr. Ball argues for the inclusion of one-third of the major maintenance costs of the Antelope Valley generating station Unit II (AVS) incurred in 2001 totaling $460,000 system-wide. Originally, Mr. Ball's argument added these additional expenses to staff's 2000 test year because the cost of the maintenance was not incurred until 2001. However, since staff is now advancing the use of 2001 operating results, Mr. Ball's testimony argues for a reduction in 2001 reported results by two-thirds of the maintenance costs. Staff therefore reduces maintenance expense in

2001 by two-thirds of the total cost testified to by Mr. Ball to properly reflect a 3 year amortization. An adjustment to reduce 2001 operating expenses by $920,000 is therefore necessary.

MISO RTO

Mr. Ball argues that revenue streams related to MAPP Service Schedule F for power transmitted on or across its system will disappear as a result of MDU joining the Midwest Independent System Operator Inc. (MISO) regional transmission organization (RTO). MDU further asserts through its responses to staff's inquiries that no savings or additional off-system sales will occur because of MDU's decision to join MISO. Staff has no proof to the contrary that these revenues will be lost and therefore accepts Mr. Ball's 2000 adjustment totaling annual lost revenues of $563,000 on a system-wide basis.

Labor

Mr. Ball makes a labor adjustment of $984,000 by annualizing 2000 labor expenses for wage increases occurring in 2001 and 2002. The adjustment results in projected labor expense on a total company basis of $13,326,480. According to information provided by MDU, labor expense included in 2001 totals $13,400,600. It appears that less labor expense was capitalized in 2001 thereby negating the need to make additional adjustments for 2002 wage increases. The difference is not material and staff will not make an adjustment to reduce 2001 expense levels to MDU's original projection for 2002 wage levels.

Pension and Post Retirement Benefits

Mr. Ball argues for a small increase in pension costs of $116,000 for North Dakota operations based on information received from its actuary. Staff asked for source data related to this adjustment but has not seen any information provided by the actuary. While pension costs may increase, other post retirement benefit costs may very well decrease negating the need for this adjustment. For instance, total company pension expense increased in 2001 compared to 2000. Still, when considering the other post retirement benefits, the total company pensions and benefits expense account decreased from $2,451,051 in 2000 to $2,415,359 in 2001. Staff is not convinced and proposes no adjustment to 2001 expense levels.

SISP

The Supplemental Income Security Plan (SISP) provides supplemental pension benefits to key employees. According to Mr. Ball's testimony, the extra pension benefits are necessary to attract and retain key employees.

The staff does not support the inclusion of these costs in the determination of rates. The staff reminds the commission that these benefits are in addition to health insurance, life insurance, 401k participation, profit sharing plans, incentive plans, defined benefit pension plans, social security or any other benefits accruing to MDU's employees.

The question before the commission is whether these costs are necessary to provide service. It is not possible to say what key employees would have done absent such a plan. Still, staff will try to provide some indirect proof that these costs are not necessary to provide electric service and should not be included in rates.

According to Mr. Ball, the plan has been in effect since 1982 yet the company has never sought rate recovery in any subsequent electric or gas rate cases. It seems that the company itself has not been convinced that these costs should be borne by the ratepayers.

Staff also noticed from information provided by the Company that fewer and fewer employees are participating in this plan. For instance, Montana-Dakota Utilities Co. had 38 participants in 1996 compared to 27 in 2001. Perhaps MDU recognizes that many companies have been reducing employee levels through mergers and consolidations and no longer sees the same need for this plan.

Staff is also concerned with the lack of symmetry in the plan. For instance, an employee making $50,000 would receive a monthly retirement benefit of $1,330 compared to a monthly benefit of $30,000 for an employee making $600,000 per year. In the case of the low-end employee, the monthly benefit would be 2.66% of annual salary compared to the high-end employee who would receive 5%.

In the end, the commission will have to make a judgment as to the necessity of these costs to provide electric service in North Dakota. In staff's opinion, these costs are not necessary and should be excluded for ratemaking purposes. The staff will not make an adjustment to 2001 expense levels as the company recorded these costs "below-the-line" as a non-regulated expense.

Insurance Expense

Mr. Ball makes an argument for increased insurance costs due in part to the September 11 tragedy. According to information provided for the year ended 2001, insurance expense changed very little from 2000 to 2001. Staff appreciates the conversations MDU has had with its insurance carriers but additional proof is necessary before staff is willing to include an inflation adjustment.

Contributions

Staff agrees to include North Dakota's share of contributions made to Energy Share of North Dakota and Lignite Energy Council as testified to by Don Ball totaling $33,000. An adjustment is necessary to 2001 results as charitable donations are recorded "below-the-line."

Q: DO YOU HAVE ANY OTHER RECOMMENDED ADJUSTMENTS THE COMMISSION SHOULD CONSIDER BEFORE ESTABLISHING BASE RATES?

A: Yes, I do. Staff compared 2001 results with previous years' results to determine if there were any abnormal expense levels that should be normalized for ratemaking purposes. Failure to make such an assessment would result in establishing rates that are not representative of normal expense levels. Because it is late in this proceeding, staff was not overly critical of every fluctuation in each and every account. Instead, staff identified accounts that fluctuated a great deal in comparison to recent years.

A & G Salaries

Staff noticed that administrative and general salaries increased by 20% in 2001 or $843,000 on a total company basis and that transmission supervision and engineering costs were up 35% or $294,000 on a total company basis. While the expense levels seem quite inflated in comparison to recent years, staff agreed in principal with the Company's 2002 overall labor expense projection. Therefore, staff proposes no adjustment to these inflated expense accounts, as they are primarily labor related.

Office Supplies

Staff did make an adjustment to 2001 results related to office supplies expense. The office supplies expense has been fairly stable in recent years but ballooned in 2001, as follows:

Year	(000's) Expense	
1995	$ 1,954	Actual
1996	$ 1,883	Actual
1997	$ 1,903	Actual
1998	$ 1,812	Actual
1999	$ 2,112	Actual
2000	$ 2,122	Actual
2001	$ 2,906	Actual
2002	$ 2,228	Projected
	$ (678)	Adjustment

The staff's projection for office supplies expense in 2002 is based off of 2000 expenditure levels and adjusted upward by 5% for inflationary purposes. Staff is not aware of what caused the spike in 2001 but makes the adjustment to reflect a more normal operating expense level.

Depreciation Expense

Staff inflated depreciation expense to recognize additional capital projects as budgeted by MDU.

Income Tax Expense

Income tax expense was also adjusted to recognize the impact of other adjustments discussed above.

Q: PLEASE SUMMARIZE STAFF'S ADJUSTMENTS, NET REGULATED INCOME, AND ITS RECOMMENDED REVENUE EXCESS.

A: The following schedule depicts staff's net regulated adjustments.

	(Thousands)		
Description	Total Company	N.D. Factor	North Dakota
Eliminate Ins. Recovery from Margins	$ (810)	66%	$ (538)
Eliminate demand penalities	$ (458)	69%	$ (316)
3 amortization of AVS maintenance	$ (920)	69%	$ (635)
Eliminate Sch. F revenues	$ 563	66%	$ 370
Include Energy Share & Lignite Council	$ 46	72%	$ 33
Normalize office supplies expense	$ (678)	66%	$ (447)
Adjust depreciation for capital projects			$ 77
Tax impact of other adjustments			$ 151

The following schedule depicts staff's resulting net regulated income.

Description	2001	Adjustments	Projected 2002
Residential	$33,403		$33,403
Small Commercial	17,603		17,603
Large Commercial	28,802		28,802
Public Street Lighting	1,450		1,450
Sales to Public Authorities	1,213		1,213
Other Operating Revenues	2,768		2,768
Unbilled Revenue	(824)		(824)
Sales for Resale	17,687	(538)	17,149
Total Revenues	$102,102	($538)	$101,564
Cost of Fuel & Purchased Pwr			
Other O&M:			
Production Expense	$40,671	($951)	$39,720
Transmission Expense	3,915	370	4,285
Distribution Expense	5,010		5,010
Customer Accounts	2,233		2,233
Customer Service & Info.	113		113
Sales Expense	281		281
Administration & General	8,968	(414)	8,554
Total Other O&M	$61,191	($995)	$60,196
Depreciation	$11,955	$77	12,032
Taxes Other Than Income	$4,019		4,019
Income Tax Expense	$7,955	$151	8,106
Net Regulated Income	$16,982	$229	$17,211

The following schedule depicts staff's recommended excess earnings.

Description	Projected 2002
Rate Base	$128,902
ROR Required	9.92%
Return Required	$12,787
Return Earned	$17,211
Return Deficiency (Excess)	($4,424)
Tax Factor	1.656
Revenue Deficiency (Excess)	($7,327)

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

Sales for Resale Margins

Rebuttal Attachment MRD-1

Total Company Actual Results

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1996:													
Kwh Sales	43,099,000	47,089,000	68,998,000	34,198,000	9,584,000	30,410,000	25,890,000	18,244,000	12,013,826	4,500,638	31,737,616	48,771,000	374,535,080
Revenues	$ 669,023	$ 716,303	$ 1,075,132	$ 492,011	$ 138,431	$ 546,309	$ 463,977	$ 342,244	$ 250,771	$ 89,504	$ 609,287	$ 860,539	$ 6,253,531
Fuel Cost	480,822	498,168	755,687	378,555	103,464	357,594	306,504	230,844	168,202	63,784	420,591	573,451	4,337,665
Margin	$ 188,202	$ 218,135	$ 319,445	$ 113,456	$ 34,967	$ 188,715	$ 157,473	$ 111,400	$ 82,568	$ 25,720	$ 188,696	$ 287,089	$ 1,915,866
1997:													
Kwh Sales	33,549,000	47,962,884	33,383,000	1,802,000	9,395,000	34,576,000	33,514,000	6,563,813	30,534,000	29,218,616	42,451,000	59,004,232	361,953,545
Revenues	$ 668,282	$ 849,641	$ 571,568	$ 40,748	$ 148,874	$ 569,671	$ 864,976	$ 170,593	$ 524,535	$ 548,992	$ 920,598	$ 1,145,722	$ 7,024,199
Fuel Cost	452,227	520,395	375,299	27,942	106,474	416,782	571,803	112,047	375,590	380,487	521,839	671,322	4,532
Margin	$ 216,055	$ 329,245	$ 196,269	$ 12,806	$ 42,400	$ 152,888	$ 293,173	$ 58,546	$ 148,945	$ 168,505	$ 398,759	$ 474,401	$ 2,491,993
1998:													
Kwh Sales	40,758,000	41,158,000	47,459,000	69,442,000	53,699,000	57,016,000	50,459,000	35,733,080	26,003,616	21,977,000	66,180,000	76,655,000	586,539,696
Revenues	$ 713,799	$ 753,900	$ 835,338	$ 1,118,367	$ 1,200,784	$ 1,245,262	$ 1,209,636	$ 840,455	$ 550,019	$ 438,991	$ 1,368,436	$ 1,584,417	$11,859,402
Other Revenue						17,496	-	-	-	-	-	-	17,496
Fuel Cost	428,263	426,256	553,276	725,085	698,860	654,840	689,581	530,819	360,616	266,744	857,315	868,514	7,060,171
Margin	$ 285,535	$ 327,643	$ 282,062	$ 393,282	$ 501,924	$ 607,917	$ 520,055	$ 309,636	$ 189,403	$ 172,247	$ 511,121	$ 715,903	$ 4,816,728
1999:													
Kwh Sales	80,306,000	78,158,000	110,119,000	92,440,000	87,283,000	68,950,000	66,689,000	61,202,616	59,340,000	72,200,000	83,644,000	83,189,000	943,520,616
Revenues	$ 1,633,112	$ 1,535,893	$ 2,071,592	$ 1,831,966	$ 1,657,264	$ 1,817,207	$ 2,115,693	$ 1,820,147	$ 1,106,080	$ 1,172,225	$ 1,487,568	$ 1,457,583	$19,706,329
Other Revenue	-	-	-		45,000	45,000	45,000	45,000	45,000	45,000			270,000
Fuel Cost	968,071	874,968	1,150,294	1,018,737	952,531	1,025,788	1,209,373	882,061	642,217	678,265	933,575	867,600	11,203,480
Margin	$ 665,041	$ 660,925	$ 921,298	$ 813,229	$ 749,733	$ 836,419	$ 951,320	$ 983,086	$ 508,863	$ 538,960	$ 553,992	$ 589,982	$ 8,772,849
2000:													
Kwh Sales	75,705,000	96,622,848	84,450,000	54,665,000	59,466,624	87,269,000	55,742,000	66,350,000	100,316,000	112,189,000	66,611,000	70,932,000	930,318,
Revenues	$ 1,675,303	$ 1,906,357	$ 1,640,229	$ 996,686	$ 1,200,524	$ 2,477,281	$ 1,787,453	$ 2,235,065	$ 2,100,033	$ 2,199,392	$ 1,793,522	$ 1,826,411	$21,838,257
Other Revenue	-	-	-	-	-	240,000	120,000	120,000	120,000	120,000	33,333	33,333	786,667
Other Cost	-	-	-	-	-	106,667	53,333	53,333	53,333	53,333	-	-	320,000
Fuel Cost	1,204,392	1,086,355	919,542	618,452	605,942	1,305,412	1,262,406	1,123,689	1,135,337	1,322,646	863,247	939,160	12,386,578
Margin	$ 470,911	$ 820,002	$ 720,687	$ 378,234	$ 594,582	$ 1,305,203	$ 591,714	$ 1,178,043	$ 1,031,363	$ 943,413	$ 963,608	$ 920,585	$ 9,918,345
2001													
Kwh Sales	83,940,000	85,312,848	98,385,000	82,021,000	50,891,000	47,452,000	59,468,848	67,520,848	74,006,000	80,514,000	80,066,000	88,600,616	898,178,160
Revenues	$ 2,336,055	$ 2,212,104	$ 2,678,562	$ 2,274,682	$ 1,345,245	$ 2,088,900	$ 3,582,406	$ 4,084,659	$ 1,437,175	$ 1,575,604	$ 1,530,192	$ 1,606,122	$26,751,706
Other Revenue	33,333	33,333	33,333	33,333	-								133,333
Other Cost	-	-	-	-	-			280,000				177,836	457,836
Ins. Recovery	-	917,792	-	(179,468)	72,516								810,841
Fuel Cost	1,020,048	966,638	1,113,921	938,823	885,793	692,303	942,106	1,114,853	793,112	983,871	891,079	957,605	11,300,152
Margin	$ 1,349,341	$ 2,196,591	$ 1,597,975	$ 1,189,725	$ 531,969	$ 1,396,597	$ 2,640,300	$ 2,689,806	$ 644,063	$ 591,733	$ 639,113	$ 470,681	$15,937,892

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NORTH DAKOTA PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

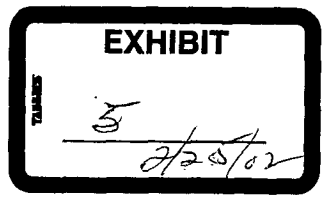
In the Matter of the Rates and Charges of MONTANA-DAKOTA UTILITIES CO. For Retail Electric Service in the State of North Dakota	))))	Case No. PU-399-01-186

REBUTTAL TESTIMONY OF

CHARLES W. KING

On behalf of the Staff of the Public Service Commission
Rate of Return

February 11, 2002



53 PU-399-01-186 Pages: 19
Rebuttal Testimony of Charles W King
by Snavely King Majoros O'Connor & Lee, Inc.
Exhibit # 5
02/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

REBUTTAL TESTIMONY OF CHARLES W. KING

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. ARE YOU THE SAME CHARLES W. KING WHO SUBMITTED DIRECT TESTIMONY IN THIS CASE ON AUGUST 11, 2001?

A. Yes. I am.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Q. WHAT IS THE OBJECTIVE OF YOUR REBUTTAL TESTIMONY?

A. This testimony has two objectives. The first objective is to respond to the direct testimony of J. Stephen Gaske on behalf of Montana-Dakota Utilities ("MDU" or "the Company"). The second objective is to update the data presented in my testimony of last August.

Q WHAT HAVE YOU FOUND TO BE THE APPROPRIATE UPDATED RATE OF RETURN FOR THE COMPANY'S NORTH DAKOTA ELECTRIC OPERATIONS?

A. Based on an update of the data presented in my August testimony, I find that the appropriate rate of return on the Company's electric operations in North Dakota is **9.92 percent,** inclusive of a return to equity of **11.7 percent.**

TESTIMONY OF J. STEPHEN GASKE

Q. AT PAGES 9 THROUGH 12 OF HIS TESTIMONY, DR. GASKE RECOMMENDS THE USE OF THE "YIELD TO MATURITY" PROCEDURE FOR QUANTIFYING DEBT COSTS, RATHER THAN THE ACCOUNTING PROCEDURE YOU ADOPTED IN YOUR INITIAL TESTIMONY. WHAT IS YOUR RESPONSE TO THIS TESTIMONY?

A. Dr. Gaske is correct that the "yield to maturity" procedure is the conventional method of calculating the cost of debt. Indeed, I am informed that the North Dakota Commission Staff normally uses that procedure.

In this instance, however, I recommend that the Commission adopt the accounting treatment that I used in my initial testimony. The reason is the extraordinarily high cost of MDU's debt. At 9.22 percent, MDU's yield to maturity debt cost is 223 basis points higher than the 6.99 percent cost of the long-term debt of Northern States Power (now Xcel Energy) and 283 basis points higher than its 6.39 percent short term debt cost.[1] It is 154 basis points higher than the 7.68 percent debt cost reported by Otter Tail Power for year-end 2000.[2] Looking at the broader bond market, the current yield on Aaa corporate bonds is 268 basis points lower than MDU's claimed debt cost; that of Baa corporate bonds is 133 basis points lower.[3] MDU is asking its ratepayers to cover what appears to be an unreasonably high cost of debt.

For this reason, I recommend that the Commission award MDU a rate of return that recovers its debt cost, inclusive of some very high redemption losses and issuance costs,

[1] Case No. PU-400-00-521, Exhibit No. 11, Schedule MPS-1, March 13, 2001.
[2] Annual Report of the Otter Tail Power Company to the North Dakota Public Service Commission.

but on a basis that reduces the burden to ratepayers. The accounting procedure I set forth in my initial testimony permits the Company to amortize its debt issuance and redemption costs over the life of the debt issues, but it reduces the debt cost to ratepayers from 9.22 percent to 8.62 percent. This reduced cost is still considerably higher than the debt cost of the other two major North Dakota investor-owned utilities.

Q. WHAT OTHER AREAS OF DISAGREEMENT DO YOU HAVE WITH DR. GASKE?

A. We disagree on the cost of MDU's equity capital. The specific areas of disagreement between Dr. Gaske and myself are the following:

- The inclusion of flotation costs,
- The selection of comparable companies,
- The procedure for estimating the coming year's dividend,
- The relevance of the Dr. Gaske's risk premium analysis,
- The relevance of Dr. Gaske's "Alternative Equity Investment Analysis."

Q. WHAT IS THE ISSUE WITH REGARD TO FLOTATION COSTS?

A. Dr. Gaske argues that there are significant costs associated with issuing new common equity capital and that these costs must be considered in determining the cost of capital. He calculates that the average flotation cost of new common stock issues of 15 electric companies during the period 1996-2000 was 4.75 percent. Accordingly, he inflates his equity return requirement by 4.75 percent.

This adjustment is wholly inappropriate.

Q. WHY DO YOU CONTEND THAT WITNESS GASKE'S FLOTATION COST ADJUSTMENT IS WHOLLY INAPPROPRIATE?

[3] www.federalreserve.gov/releases/H15

A. First of all, Dr. Gaske's flotation cost ratio does not apply to MDU. Since 1997, MDU's parent company has issued 27,061,858 new shares of common stock with a value of $579,764,238. The sum of all flotation costs for these stock issues has been $5,424,682, for a ratio of flotation cost to new stock issued of 0.94 percent, about one-fifth the ratio Dr. Gaske proposes to use.[4]

More to the point, however, is that Dr. Gaske would apply his flotation cost adjustment to the entire equity value of the company, inclusive of all stock already issued. The effect of his flotation cost adjustment is to increase his equity return by .57 percentage points. When multiplied by the $1,077 million book equity value of the Company, this allowance amounts to $6.3 million annually, which is substantially more than all the flotation costs the Company incurred during the past five years.

If a flotation cost adder is to be used, it should be equal to a reasonable estimate of the annual flotation cost incurrence divided by the entire amount of the Company's equity. In MDU's case, annual flotation costs during the past five years have been about $1.1 million. The Company's total book equity value is $1,087 million, for a flotation cost allowance of 0.1 percent. This amount is so small as to be lost in the rounding. For this reason, I recommend that there be no explicit flotation cost adder.

The data and the calculations used in this answer are presented in Exhibit_____(CWK-1R) attached to this rebuttal testimony.

Q. AT PAGE 17 OF HIS TESTIMONY, DR. GASKE STATES THAT A FLOTATION COST ALLOWANCE IS NECESSARY TO PERMIT MDU TO SELL STOCK WITHOUT DILUTING THE VALUE OF THAT STOCK. IS THIS A RELEVANT ISSUE?

[4] MDU Response to King January 22 Data Request No. 6.

A. No. As of November 2001, the book value of MDU shares was $15.58. On February 6, 2002 MDU's shares were trading at $27.79, for a market-to-book ratio of 1.78. Any sales of new MDU's stock would cause book value appreciation, not dilution.

Q. DR. GASKE CRITICIZES YOUR SELECTION OF TWO LISTS OF COMPARABLE COMPANIES, ARGUING THAT THERE IS NO STATISTICAL SIGNIFICANCE TO THE DIFFERENCES IN THE DCF AVERAGES. HOW DO YOU RESPOND TO THIS CRITICISM?

A. Dr. Gaske is correct that there are variations in the DCF returns within the two lists of companies that exceed the differences in the averages. This result is caused by two factors. The first is the smallness of the sample, particularly of the electric-only companies. With only four companies, it would require a very tight set of results, with little variation among them, to generate an average that would pass a test of statistical significance. The second reason is explained on pages 21 and 22 of my initial testimony. It is that the capital structures of the companies within the two groups create differences in financial risk that cause much of the variation among the DCF return requirements of companies having similar business risks.

The absence of statistical significance to the averages, however, does not negate the justification for making the distinction between electric-only and combination electric/gas companies. Because of the small sample, there would likely be no statistical significance to the averages of the required returns of, say, two electric utilities versus two dot-com companies, but that does not mean that the risks are not different and the required returns of the dot-coms are not higher.

If there is an objective reason for believing that one set of companies has a lower level of business risk than another, then it is still appropriate to use that sample of firms if it matches the description of the company under study. Thus, if there is reason to believe that combination firms have lower business risk than electric-only companies, and MDU

is a combination company, then it is appropriate to look to the DCF returns of the combination companies for an indication of MDU's required return.

Q. DR. GASKE ARGUES THAT IT IS MORE APPROPRIATE TO USE ELECTRIC-ONLY COMPANIES THAN COMBINATION COMPANIES IN FINDING MDU'S RATE OF RETURN. DO YOU AGREE?

A. Absolutely not. There are two reasons that combination electric/gas companies have lower business risks than electric-only companies. The first is that mentioned in my initial testimony, that electricity and gas are to some extent competitive, so that a utility controlling both enjoys a much stronger market position than one controlling only the electricity side. Dr. Gaske denies this, contending that MDU's natural gas distribution system is primarily used to provide heat and is not used to provide lighting or to run appliances such as television, dishwashers, etc. Electricity, contends Dr. Gaske, is not used for home heating except where natural gas is not available.

The competitiveness of electricity and gas for space heating is to some extent a function of climate. In warmer climates, where heat pumps are feasible, electricity is a very active competitor with gas for home heating. But even in North Dakota, MDU estimates that it has 5,400 residential customers who use electricity for home heating.[5] For two other types of appliances, electricity and gas are quite competitive, as indicated by MDU's own figures on residential saturation:[6]

	Electricity	Gas
Water Heating	23.77%	64.54%
Cooking	84.35%	14.05%

Dr. Gaske goes on to argue that even if inter-energy competition exists, MDU has very little ability to control the costs of the respective energy sources, particularly their fuels, so that has limited ability to induce customers to select one form of energy over another.

[5] MDU Response to King's January 22, 2002 data request no. 11.
[6] MDU Response to King's January 22, 2002 data request no. 12.

That, of course, is exactly the point. The inability of a utility to induce its customers to use electricity for, say, heating or cooking is a risk borne solely by electric-only utilities. A combination utility avoids that risk because the customer remains its customer regardless of his/her choice of fuel.

The other risk-reducing factor enjoyed by combination utilities but not by electric-only companies relates to weather. In most of the country, peak electric consumption is driven by air conditioning, so that fluctuations in summer weather patterns constitute a major business risk. The earnings of gas utilities are susceptible to winter weather fluctuations. Either an electric-only or gas-only utility is exposed to the vagaries of a single season's weather. Combination utilities' risk is spread over two seasons. A low winter may be offset by a high summer or vice versa. This risk-reducing characteristic has to be recognized by investors. Indeed, it shows up in the evident earnings requirements of combination vs. electric-only utilities.

Q. DO YOU HAVE ANY COMMENTS ON DR. GASKE'S SELECTION OF 12 UTILITIES AS PROXIES FOR MDU?

A. Dr. Gaske has selected 12 utilities, nine of which are also among the utilities I used in my analysis. Dr. Gaske captures three additional utilities, IDACORP (Idaho Power), American Electric Power (AEP), and Cleco Corp. by reducing the threshold on regulated retail revenue from the 85 percent I used to 75 percent. This is an important difference. The three additional companies raise Dr. Gaske's DCF results substantially. His "Investor Required Return," exclusive of his flotation cost adjustment, for these three companies are as follows:

	"Basic DCF"[7]	"2nd Stage Retention DCF[8]
IDACORP	15.38%	13.60%
AEP	12.47%	12.47%
Cleco	14.34%	13.67%

[7] Exhibit_____(JSD-1), Schedule 4, page 7.
[8] Id., page 6.

These return requirements are part of a list that averages to 12.44 percent for the "Basic DCF" and 12.10 percent of the "Second Stage Retention DCF." Without these three utilities, these average return requirements reduce to 11.9 percent and 11.7 percent, respectively.

These three companies should not be included in a proxy group for purposes of finding the equity return for regulated retail operations, whether electric or gas. In each case, the driving factor in investors' assessments of these companies is either their wholesale electric operations, which are effectively unregulated, or their non-utility activities. This fact is evident in the *Value Line* reports, which I attach as an Exhibit____(CWK-2R) to this testimony. Here are the opening lines of the commentaries on each of these companies:

> IDACORP: "IDACORP's noncore enterprises are an important source of income."
>
> AEP: "Thanks largely to American Electric Power's wholesale business, earnings have recovered nicely in 2001"
>
> Cleco Corp: "Cleco's nonregulated generating strategy should produce solid earnings growth in 2002."

In each case, the prospect of increased earnings from non-regulated activities is the driver of earnings expectations. Being unregulated, these activities are potentially more profitable but also more risky than regulated retail utility service. They therefore create higher earnings requirements. Those earnings requirements are inappropriate as a proxy for MDU's retail electric service.

Q. WHAT IS THE NATURE OF YOUR DISAGREEMENT WITH DR. GASKE AS REGARDS THE ADJUSTMENT FOR THE COMING YEAR DIVIDEND?

A. The DCF procedure requires that the dividend used in the dividend yield calculation should be the expected dividend for the coming year. The conventional procedure is to inflate the current dividend by some fraction of the "g" or annual growth factor in anticipation that there will be an increase in the dividend in the coming year. Dr. Gaske uses .625g, while I used .5g.

Dr. Gaske's factor is wrong because it assumes that the investor will not receive his/her first dividend until exactly three months from the date of purchase. The average for the next dividend increase is thus (.25+.50+.75+1.0)/4 = .625. My .5g factor assumes that the probability of the dividend increase is randomly distributed throughout the year following the purchase of the stock. The average delay in the dividend increase under this assumption is one-half a year, so that the appropriate factor is .5g.

The effect of this disagreement on the final result, however, is minimal.

Q. WHY DO YOU DISAGREE WITH DR. GASKE'S RISK PREMIUM ANALYSIS?

A. Dr. Gaske purports to measure the required return to equity by adding the historical difference in experienced earnings from stocks and bonds to the current levels of bond yields. These historical differences, as measured by Ibbotson Associates, go back to 1926.

I have encountered this historical risk premium approach in a number of rate-of-return proceedings and have always found it so flawed, both conceptually and statistically, as to be virtually worthless.

The historical risk premium approach calculates the experienced returns to common stocks, bonds and Treasury bills on a monthly basis since 1926. It then assumes that the experienced differences in return between stocks and bonds represent the expected differences in return. The theory is that over a long enough period, actual return

differentials between stocks and bonds will equate to required or expected return differentials.

This is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as has to have been the case during the last year), what possible logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations? Moreover, it is flatly untrue that the differential in required returns between bonds and stocks is fixed and unchanging, as this theory postulates. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

Quite apart from this conceptual failing, the theory fails statistically. The standard deviations of the observations, particularly the observations of the return differences, are greater than the mean of those observations. The means therefore lack statistical significance and are useless as a predictive tool.

Q. WHY DO YOU DISAGREE WITH DR. GASKE'S ALTERNATIVE EQUITY INVESTMENT ANALYSIS?

A. Dr. Gaske purports to demonstrate that MDU should be allowed a high return by observing that the returns to book equity on 746 industrial firms included in *The Value Line Investment Survey* have ranged from 27.57 percent to 31.75 percent over the five years 1996-2000. He argues that the average of 29.4 percent, along with the return of 20.69 percent experienced by S&P's 500 companies, represents a "benchmark" which suggests that the 12.75 percent he proposes for MDU is quite low.

This comparison is utterly irrelevant. Investors in industrial firms have no access to book equity value. The only value that is meaningful for investors in such firms is the market value. That is what an investor must pay to acquire the stock, and conversely, the value

an investor will receive by selling the stock. Book equity value in an industrial firm is a purely historical number representing the dollars of original investment in equity capital contributed to (or retained by) the company. It has little relevance to the current market value, even for fairly capital intensive firms. Since most stocks sell well above their book value, the return that is accessible to investor is considerably less than the 20 to 30 percent noted by Dr. Gaske.

Book values are relevant for regulated utilities because regulation makes them so. Regulation sets the earnings allowance for such companies relative to a rate base reflective of the book value of the capital invested utility operations. This condition does not apply to industrial firms.

UPDATED RETURN CALCULATION

Q. HAVE YOU UPDATED THE DATA CONTAINED IN YOUR AUGUST 11 TESTIMONY?

A. Yes. Exhibit___(CWK-3R) contains updated data as of February 2, 2002 for the inputs to the DCF analysis I presented last August. Specifically, it shows the latest 5-year consensus growth forecast as reported by Zacks Investors Services, the most recent 50-day market price as reported by CBS MarketWatch, and the most recent dividend for each of the four comparison electric companies and for the eight combination gas/electric utilities. For comparison purposes, I have shown in the last column the DCF returns I found for each company last August.

The exhibit reveals that while individual company returns have changed, there is no change in the 12.1 percent average for the four electric-only utilities. The average return for the eight combination utilities has increased from 11.2 percent to 11.7 percent.

Q. DO YOU THEREFORE REVISE YOUR RECOMMENDED RETURN TO MDU'S EQUITY CAPITAL?

A. Yes, I do. I recommend that MDU's equity capital return be revised to 11.7 percent. It is notable that this return corresponds exactly to the "investor required return" calculated by Dr. Gaske under the "second state retention growth DCF calculation" for the nine utilities in his comparison group that derive more than 85 percent of their revenue from regulated retail services.[9] It is only 20 basis point below the "basic DCF" calculation for the same nine companies.[10]

Q. WHAT IS YOUR RECOMMENDED RETURN TO TOTAL CAPITAL?

A. My recommended return to total capital is **9.92 percent**, calculated as follows:

Item	Proportion	Cost	Weighted Cost
Debt	45.90%	8.62%	3.96%
Preferred Stock	5.23%	4.63%	0.24%
Equity	48.87%	11.7%	5.72%
Total	100.00%		**9.92%**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

[9] Exhibit___(JSG-2), Schedule 4, page 6.
[10] Id., page 7.

Exhibit_____(CWK-1R)

MDU Resources
Stock Flotation Costs
Source: DR 6

		A Flotation Cost	B Amount Raised	C Shares
1	DRIP	55,330	9,903,801	553,296
2	401K	35,141	6,515,221	351,405
3	Acquisition	120,000	401,676,428	20,286,502
4	Equity Draw Down	5,214,211	157,411,736	5,751,785
5	Employee Stock Option		4,257,052	118,870
6	Total	5,424,682	579,764,238	27,061,858
7	Flotation Cost/Amount Raised	0.94%		
8	Outstanding Shares 11/01			69,148,379
9	Book Value per Share DR 10			$ 15.58
10	Market Value per Share DR 10			$ 24.56
11	Book Equity Value 11/01			$ 1,077,331,745
12	Market Equity Value 11/01			$ 1,698,284,188
13	Annual Flotation Cost (6C/5)	$ 1,084,936		
14	Flotation Cost/Book Value	0.10%		

Gaske Flotation Cost Adder:

		Before Flotation	After Flotation	Difference
	Schedule 4, page 6			
15	Average	12.10%	12.67%	0.57%
16	High	14.68%	15.38%	0.70%
17	Median	12.03%	12.60%	0.57%
18	Low	9.71%	10.17%	0.46%
	Schedule 4, page			
19	Average	12.44%	13.03%	0.59%
20	High	15.38%	16.11%	0.73%
21	Median	12.49%	13.09%	0.60%
22	Low	9.65%	10.11%	0.46%
23	Average	12.31%	12.90%	0.58%
24	Gaske's Annual Flotation Allowance			$ 6,302,391

Exhibit_____(CWK-2R)

Value Line **Reports for**

IDACORP
American Electric Power
Cleco Corp.

IDACORP, INC. NYSE-IDA

RECENT PRICE 37.76 | P/E RATIO 11.9 (Trailing: 11.0) (Median: 14.0) | RELATIVE P/E RATIO 0.67 | DIV'D YLD 4.9% | VALUE LINE 1786

TIMELINESS 4 Lowered 5/11/01
SAFETY 2 Raised 8/23/96
CHNICAL 2 Raised 11/16/01
dETA .50 (1.00 = Market)

2004-06 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	6%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	2	0	0	2	0	0	0

Institutional Decisions

	4Q2000	1Q2001	2Q2001
to Buy	84	79	68
to Sell	65	73	74
Hld's(000)	11980	12161	12203

High: 29.4 28.8 28.8 33.0 30.6 30.0 34.3 37.8 38.1 36.5 53.0 49.4
Low: 22.8 24.3 24.4 27.3 21.8 23.4 27.3 28.5 29.9 26.0 25.9 33.6

LEGENDS
1.06 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2004 2005 2006

80 60 50 40 32 24 20 16 12 10 8 6 4

Percent shares traded 6.0 4.0 2.0

% TOT. RETURN 10/01

	THIS STOCK	VL ARITH. INDEX
1 yr.	-19.4	-4.6
3 yr.	35.2	24.2
5 yr.	52.2	64.2

1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	© VALUE LINE PUB., INC.	04-06
13.33	12.03	11.61	12.14	14.60	13.68	14.22	13.76	14.57	14.45	14.51	15.38	19.90	29.83	17.50	27.10	*34.30*	*30.30*	Revenues per sh	*33.50*
3.48	3.45	2.79	2.84	3.93	3.53	3.26	3.16	3.53	3.39	3.89	4.05	4.22	4.69	4.50	5.63	*5.50*	*5.45*	"Cash Flow" per sh	*6.00*
2.16	2.00	1.30	1.32	2.37	1.91	1.56	1.55	1.97	1.80	2.10	2.21	2.32	2.37	2.43	3.50	*3.25*	*3.05*	Earnings per sh A	*3.20*
1.70	1.76	1.80	1.80	1.83	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	*1.86*	*1.86*	Div'd Decl'd per sh B■	*1.86*
2.19	1.48	1.15	1.64	1.78	2.29	3.94	3.26	3.32	2.94	2.23	2.49	2.51	2.37	2.95	3.73	*4.80*	*4.00*	Cap'l Spending per sh	*3.20*
17.29	17.46	17.29	16.81	17.35	17.40	17.06	17.28	17.86	17.91	18.15	18.47	18.93	19.42	20.02	21.82	*23.20*	*24.40*	Book Value per sh C	*28.30*
33.86	33.98	33.98	33.98	33.98	33.98	33.98	36.19	37.09	37.61	37.61	37.61	37.61	37.61	37.61	37.61	*37.60*	*37.60*	Common Shs Outst'g E	*37.60*
9.8	13.3	19.2	17.1	10.9	13.4	16.8	17.0	15.4	13.9	12.4	13.7	13.6	14.4	12.7	10.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
.80	.90	1.28	1.42	.83	1.00	1.07	1.03	.91	.91	.83	.86	.78	.75	.72	.72			Relative P/E Ratio	*.95*
8.1%	6.6%	7.2%	8.0%	7.1%	7.2%	7.1%	7.1%	6.1%	7.4%	7.2%	6.1%	5.9%	5.4%	6.0%	4.9%			Avg Ann'l Div'd Yield	*4.0%*
483.2	498.1	540.4	543.7	545.6	578.5	748.5	1122.0	658.3	1019.4	*1290*	*1140*	Revenues ($mill)	*1260*
57.9	60.0	78.2	74.9	86.9	90.6	92.3	94.8	96.9	137.6	*130*	*120*	Net Profit ($mill)	*125*
26.8%	27.9%	31.8%	31.4%	35.8%	36.5%	33.5%	32.0%	32.0%	32.1%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
6.9%	8.2%	7.1%	4.6%	1.7%	.4%	.6%	1.3%	3.2%	3.6%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
47.8%	48.9%	48.6%	48.2%	45.2%	48.0%	46.2%	49.4%	48.9%	48.3%	*49.5%*	*48.5%*	Long-Term Debt Ratio	*45.0%*
44.0%	43.6%	44.5%	44.9%	45.9%	45.1%	46.8%	44.2%	44.8%	45.9%	*45.0%*	*46.0%*	Common Equity Ratio	*50.0%*
1318.0	1435.2	1488.9	1499.5	1487.6	1540.1	1522.2	1652.3	1680.3	1790.0	*1940*	*1990*	Total Capital ($mill)	*2135*
1529.3	1585.5	1616.4	1656.6	1672.9	1694.6	1716.9	1711.5	1745.7	1805.0	*1900*	*1960*	Net Plant ($mill)	*2030*
6.5%	6.0%	7.1%	6.7%	7.6%	7.6%	7.8%	7.3%	7.4%	9.2%	*8.0%*	*7.5%*	Return on Total Cap'l	*7.5%*
8.4%	8.2%	9.8%	9.3%	10.7%	11.3%	11.3%	11.3%	11.3%	14.9%	*13.0%*	*12.0%*	Return on Shr. Equity	*11.0%*
9.2%	8.7%	10.9%	10.0%	11.6%	11.9%	12.2%	12.2%	12.1%	16.0%	*14.0%*	*12.5%*	Return on Com Equity F	*11.5%*
NMF	NMF	.7%	NMF	1.3%	1.9%	2.4%	2.6%	2.9%	7.5%	*6.0%*	*5.0%*	Retained to Com Eq	*4.5%*
117%	118%	94%	103%	90%	86%	82%	80%	78%	55%	*59%*	*63%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 6/30/01
Total Debt $1093.0 mill. Due in 5 Yrs $411.2 mill.
LT Debt $899.6 mill. LT Interest $55.2 mill.
(LT interest earned: 6.4x)

Pension Liability None

Pfd Stock $104.7 mill. Pfd Div'd $5.8 mill.
551,156 shs. 4% to 7.68% cum., $100 par, callable $100.35 to $104.00; 500 shs. $100,000 stated value.

Common Stock 37,412,136 shs.
MARKET CAP: $1.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	1998	1999	2000
% Change Retail Sales (KWH)	+1.0	+3.0	+6.0
Avg. Indust. Use (MWH)	19548	19905	20843
Avg. Indust. Revs. per KWH (¢)	2.83	2.69	2.78
Capacity at Peak (Mw)	2691	2839	3011
Peak Load, Summer (Mw)	2747	2839	2919
Annual Load Factor (%)	82.0	82.0	82.0
% Change Customers (yr-end)	+2.9	+3.4	+2.4
Fixed Charge Cov. (%)	266	233	329

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '98-'00 to '04-'06
Revenues	6.5%	11.5%	*5.0%*
"Cash Flow"	3.5%	6.5%	*3.5%*
Earnings	4.0%	7.0%	*2.5%*
Dividends	--	--	*Nil*
Book Value	1.5%	2.5%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	238.2	221.6	392.4	269.8	1122.0
1999	174.1	165.1	162.0	157.1	658.3
2000	186.3	254.6	301.0	277.5	1019.4
2001	246.4	329.2	398.0	*316.4*	*1290*
2002	*230*	*300*	*340*	*270*	*1140*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.75	.54	.59	.49	2.37
1999	.78	.56	.59	.50	2.43
2000	.90	.86	1.11	.63	3.50
2001	.93	.96	.91	*.45*	*3.25*
2002	*.85*	*.80*	*.90*	*.50*	*3.05*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1997	.465	.465	.465	.465	1.86
1998	.465	.465	.465	.465	1.86
9	.465	.465	.465	.465	1.86
0	.465	.465	.465	.465	1.86
2001	.465	.465	.465		

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a hydroelectric utility that also partly owns three coal plants and markets natural gas through trading operations. It sells electricity in Idaho (86% of revs.), Oregon (4%), wholesale (10%). Revenue breakdown: residential, 40%; commercial, 23%; industrial, 24%; other, 13%. Fuel and purchased power cost: 47% of '00 rev.; estimated labor costs: 9.7%. 2000 depreciation rate: 2.9%. Fuel sources: hydro, 41%; thermal, 38%; purchased power & other, 21%. Has 2,044 employees, 21,886 common stockholders. Chairman: Jon H. Miller. CEO & Pres.: Jan B. Packwood. Incorporated: Idaho. Addr.: 1221 W. Idaho St., Boise, Idaho 83702. Tel.: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's noncore enterprises are an important source of income. The wholesale energy subsidiary, which operates in 31 states, Canada, and Mexico, will likely be a major profit driver over the next 3 to 5 years. Too, IDA invests in affordable housing, which generates profits through income tax credits. It also has an interest in 12 unregulated hydro plants that are steady contributors to net. Other subsidiaries, still in startup stages and not expected to be profitable for a few years, include a telecommunications unit and a provider of energy-related products and services. Finally, the company owns 70% of a fuel cell business that has a patent on four reformers that convert hydrogen fuels into electricity. It already has contracts for $3.5 million for the sale of 110 units to the Bonneville Power Administration, and it is pursuing orders in Japan and France. These varied activities will likely produce 40% of company profits by 2004.

The company will need new generation shortly. IDA's 2000 resource plan projected an electricity shortfall in its service area by mid-2004. Until that time, it should be able to buy sufficient power to fulfill its requirements. But by 2004, transmission restraints will limit increased purchases, and IDA will need additional capacity. Accordingly, it selected Garnet, a low-cost builder, to construct a 250-megawatt gas-fired unit. The plant, targeted for operation in mid-2004, will serve basic ratepayers and will sell part of its output in the open market.

Earnings probably won't match 2000's record performance. Though wholesale energy sales are strong, they will be less than those of last year. Too, subpar winter snowpack will reduce hydro generation and increase the need for more costly coal-fired output. Thus, despite a 2% increase in retail sales, we estimate a 7% decline in 2001 earnings, to $3.25 a share. An expected drop in wholesale energy prices indicates a further decline next year.

The yield here is a cut above that of the group. But don't expect a hike in the disbursement for a while, because of the need to preserve funds for new construction and the fuel cell business. This untimely stock is not recommended for investors interested in dividend growth.

Arthur H. Medalie *November 16, 2001*

(A) EPS diluted. Excl. nonrecurring gains (losses): '87, 33¢; '93, 16¢; '00, 22¢. Next egs. report due late Jan. (B) Next div'd meeting about Jan. 19. Goes ex about Jan. 23. Div'd pmnt. dates about the 28th of Feb., 30th of May, Aug., Nov. ■ Div'd reinvestment plan available upon request. (C) Incl. deferred debits. In '00: $13.65/sh. (D) 1999 sales do not include trading revs. (E) In mil. (F) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '95: 11.0%. Earned on '00 avg. system com. eq.: 16.7%. Regul. Clim.: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	80

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AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 44.10 | P/E RATIO 12.2 (Trailing: 20.1, Median: 13.0) | RELATIVE P/E RATIO 0.79 | DIV'D YLD 5.4% | VALUE LINE 699

TIMELINESS — Suspended 9/8/00
SAFETY 2 Raised 9/12/97
TECHNICAL — Suspended 9/8/00
BETA .55 (1.00 = Market)

2004-06 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+70%)	18%
Low	55	(+25%)	10%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	1	0	0	0	0	0	1	1	0
Options	0	0	0	1	0	0	0	0	0
to Sell	0	0	0	1	0	1	1	0	0

Institutional Decisions

	4Q2000	1Q2001	2Q2001
to Buy	182	171	182
to Sell	154	175	140
Hld's(000)	165971	173238	188527

	High:	33.1	34.3	35.1	40.3	37.4	40.6	44.8	52.0	53.3	48.2	48.9	51.2
	Low:	26.0	26.6	30.4	32.0	27.3	31.3	38.6	39.1	42.1	30.6	25.9	39.3

LEGENDS
0.99 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2004 | 2005 | 2006

100 80 64 48 40 32 24 20 16 12 8 6

Percent shares traded 9.0 6.0 3.0

% TOT. RETURN 8/01

	THIS STOCK	VL ARITH. INDEX
1 yr.	37.5	1.8
3 yr.	16.7	56.0
5 yr.	41.8	87.6

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules. The data on this page prior to 2000 do not reflect the addition of CSW.

CAPITAL STRUCTURE as of 6/30/01
Total Debt $16010 mill. Due in 5 Yrs $9374 mill.
LT Debt $10931 mill. LT Interest $765 mill.
Incl. $322 mill. 7.875%-8.00% Mandatorily Redeemable Preferred Securities of Subsidiary Trusts.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $244 mill.
Pfd Stock $161 mill. Pfd Div'd $9 mill.
614,608 shs. 4%-5%, cum., 333,100 shs. 5.90%-5.92%, cum., 513,450 shs. 6.02%-6¼%, cum., 150,000 shs. 7%, cum. Incl. 996,550 shs. subj. to mandatory redemption.
Common Stock 322,201,830 shs.
as of 7/31/01
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	1998	1999	2000
% Change Retail Sales (KWH)	+1.8	-1.1	+5.4
Avg. Indust. Use (MWH)	NA	NA	1437
Avg. Indust. Revs. per KWH (¢)	NA	NA	3.90
Capacity at Peak (Mw)	23759	23759	23790
Peak Load (Mw)	23192	23392	23223
Annual Load Factor (%)	62.7	NA	NA
% Change Customers (yr-end)	NA	NA	+1.2
Fixed Charge Cov. (%)	289	236	170

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd 2000 to '04-'06
Revenues	3.5%	4.5%	54.0%
"Cash Flow"	--	--	13.5%
Earnings	-3.5%	-4.5%	35.5%
Dividends	--	--	Nil
Book Value	1.5%	2.0%	6.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	1510	1561	1845	1430	6345.9
1999	1694	1643	1914	1665	6916.0
2000	3021	3169	3915	3589	13694
2001	14238	14528	*18000*	*16234*	*63000*
2002	*17000*	*18000*	*22000*	*20000*	*77000*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.79	.62	1.02	.38	2.81
1999	.79	.46	.90	.54	2.69
2000	.43	d.03	1.11	d.47	1.04
2001	.83	.87	*1.25*	*.75*	*3.70*
2002	*.75*	*.80*	*1.45*	*.85*	*3.85*

Calendar	QUARTERLY DIVIDENDS PAID B= Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1997	.60	.60	.60	.60	2.40
1998	.60	.60	.60	.60	2.40
1999	.60	.60	.60	.60	2.40
2000	.60	.60	.60	.60	2.40
2001	.60	.60	.60		

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	© VALUE LINE PUB., INC.	04-06
	27.35	27.34	28.55	29.72	30.38	31.07	32.43	33.08	35.63	42.53	*195.35*	*238.40*	Revenues per sh	*369.25*
	5.65	5.30	5.71	5.79	6.02	6.31	6.47	6.03	6.36	5.11	*8.15*	*8.45*	"Cash Flow" per sh	*9.75*
	2.70	2.54	2.70	2.71	2.85	3.14	3.28	2.81	2.69	1.04	*3.70*	*3.85*	Earnings per sh A	*4.75*
	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	*2.40*	*2.40*	Div'd Decl'd per sh B=	*2.40*
	3.38	3.39	3.21	3.47	3.25	3.07	4.00	4.13	4.47	5.51	*5.25*	*5.25*	Cap'l Spending per sh	*3.00*
	22.88	23.01	22.50	22.83	23.25	24.15	24.62	25.24	25.79	25.01	*26.20*	*27.70*	Book Value per sh C	*34.25*
	184.54	184.54	184.54	185.24	186.64	188.24	189.99	191.82	194.10	322.02	*322.50*	*323.00*	Common Shs Outst'g D	*325.00*
	11.0	12.6	13.6	11.7	12.3	13.2	13.4	17.0	14.3	NMF	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*13.5*
	.70	.76	.80	.77	.82	.83	.77	.93	.82	NMF			Relative P/E Ratio	*.90*
	8.1%	7.5%	6.5%	7.6%	6.9%	5.8%	5.5%	5.0%	6.2%	6.7%			Avg Ann'l Div'd Yield	*3.7%*
	5048.6	5044.8	5268.8	5504.7	5670.3	5849.2	6161.4	6345.9	6916.0	13694	*63000*	*77000*	Revenues ($mill)	*120000*
	551.5	527.7	557.1	554.7	584.7	628.9	638.2	547.1	532.0	332.0	*1200*	*1255*	Net Profit ($mill)	*1580*
	26.5%	24.0%	26.7%	28.1%	31.8%	35.2%	34.8%	36.6%	32.8%	68.1%	*38.5%*	*35.0%*	Income Tax Rate	*35.0%*
	4.6%	1.8%	1.6%	1.8%	1.7%	1.8%	1.6%	1.7%	1.9%	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
	49.5%	50.6%	50.2%	48.1%	49.6%	48.2%	51.4%	57.6%	55.1%	52.9%	*57.0%*	*55.0%*	Long-Term Debt Ratio	*51.0%*
	43.6%	41.9%	42.0%	43.4%	43.7%	45.7%	46.9%	41.0%	43.5%	44.4%	*42.0%*	*44.5%*	Common Equity Ratio	*48.5%*
	9687.5	10137	9885.1	9739.8	9923.5	9942.3	9981.0	11815	11508	18151	*20075*	*20175*	Total Capital ($mill)	*22900*
	11196	11228	11100	11348	11385	11420	11633	11730	13055	22393	*22650*	*22875*	Net Plant ($mill)	*21300*
	7.8%	7.3%	7.7%	7.6%	7.8%	8.1%	8.1%	8.2%	8.6%	3.8%	*8.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
	11.3%	10.5%	11.3%	11.0%	11.7%	12.2%	13.2%	10.9%	10.3%	4.0%	*14.0%*	*14.0%*	Return on Shr. Equity	*14.0%*
	11.8%	11.0%	12.0%	11.8%	12.2%	12.9%	13.3%	11.1%	10.4%	4.0%	*14.0%*	*14.0%*	Return on Com Equity E	*14.0%*
	1.3%	.6%	1.3%	1.3%	1.9%	3.0%	3.6%	1.6%	1.1%	NMF	*5.0%*	*5.5%*	Retained to Com Eq	*7.0%*
	90%	95%	90%	90%	86%	78%	74%	86%	89%	NMF	*65%*	*62%*	All Div'ds to Net Prof	*50%*

BUSINESS: American Electric Power Co., Inc. (AEP), via ten operating utilities, serves 4.9 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Retail revenues (pre-merger AEP): residential, 41%; commercial, 28%; industrial, 28%; other, 3%. Has a 100% interest in SEEBOARD (British utility); sold 50% stake in Yorkshire Holdings (British utility) 1Q/01. Generating sources (combined AEP), '00: coal, 30%; gas, 5%; nuclear, 2%; purchased, 63%. Fuel costs: 30% of revs. '00 deprec. rate: 3.5%. Has 28,400 employees, 330,000 stockholders. Chairman & CEO: Dr. E. Linn Draper, Jr. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-223-1000. Internet: www.aep.com.

Thanks largely to American Electric Power's wholesale business, earnings have recovered nicely in 2001. AEP, the second-largest player in power trading and marketing in the United States, is now among the top five in gas trading and marketing as well. (The acquisition of a gas pipeline in Houston has helped in this regard.) Trading volume is way up—hence the sharp increase in revenues—and margins are solid. We estimate that earnings rose in the September period, despite an unplanned outage of the Cook nuclear station that cost the company several cents a share during the quarter. Our 2001 earnings estimate is above management's targeted range of $3.50-$3.60 a share because we are including a $0.14-a-share gain the company booked in the first quarter on the sale of an independent power project. Such gains are common in this business.

We look for another good year in 2002. The size and asset base of AEP's marketing business suggest that its good performance is sustainable, rather than merely a result of the unusual volatility in the markets this year. Also, AEP should be able to increase the merger-related benefits stemming from its purchase of Central and South West (CSW) in 2000. Finally, the cessation of goodwill amortization will boost share net by $0.12 next year.

AEP has filed a corporate separation plan. The company would remain intact—for now—but its nonregulated and regulated businesses would be functionally separated. It needs the approval of the Federal Energy Regulatory Commission, the SEC, and various state commissions. Eventually, the company might split into two companies (regulated and nonregulated), as a number of utilities are doing. But it can't initiate such a move until mid-2002 due to restrictions stemming from pooling-of-interests accounting, which was used in the CSW merger. Likewise, the sale of SEEBOARD (a British utility that came over with CSW and doesn't fit AEP's strategy) will have to wait until then.

This stock is worth a look. (It is unranked for Timeliness due to its brief trading history since the CSW deal.) The yield is above average even by utility standards. And if AEP winds up splitting itself, the sum of the parts might exceed the whole.

Paul E. Debbas, CFA *October 5, 2001*

(A) Excludes extraordinary losses: '93, 78¢; '97, 58¢; '98, 8¢; '00, 21¢; 2Q '01, 15¢. Next earnings report due late Oct. (B) Next dividend meeting about Oct. 24. Goes ex about Nov. 7. Approx. div'd payment dates: 10th of Mar., June, Sept., Dec. = Div'd reinvestment plan available. (C) Incl. intangibles. In '00: $5.08 bill., $15.78/sh. (D) In millions. (E) Rate base: various. Rates allowed on common eq.: 10.0%-14.5%; earned on avg. com. eq., '00: 4.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	20
Earnings Predictability	60

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CLECO CORPORATION NYSE-CNL

RECENT PRICE 19.70 | P/E RATIO 13.1 (Trailing: 14.2, Median: 13.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.5% | VALUE LINE 702

TIMELINESS 4 Lowered 8/10/01
SAFETY 2 Lowered 10/6/00
TECHNICAL 4 Lowered 10/5/01
BETA .55 (1.00 = Market)

2004-06 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	14%
Low	25	(+25%)	10%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2000	1Q2001	2Q2001
to Buy	63	64	76
to Sell	51	59	45
Hld's(000)	23700	24157	24623

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	© VALUE LINE PUB., INC.	04-06
High:	9.1	12.3	13.1	13.6	12.8	14.1	14.6	16.6	18.1	17.8	28.3	27.3								
Low:	7.9	8.6	11.4	11.5	10.4	11.0	12.6	12.4	14.3	14.1	15.1	19.4								
	7.09	6.65	6.79	6.71	7.04	7.42	7.58	7.88	8.54	8.48	8.79	9.70	10.16	11.46	17.12	18.23	*25.55*	*28.35*	Revenues per sh	*36.75*
	1.34	1.39	1.56	1.61	1.62	1.66	1.76	1.78	1.74	1.85	1.99	2.11	2.18	2.28	2.36	2.77	*3.05*	*3.45*	"Cash Flow" per sh	*4.75*
	.91	.81	.88	.90	.89	.93	.96	.97	.89	.96	1.04	1.12	1.09	1.12	1.19	1.46	*1.45*	*1.65*	Earnings per sh A	*2.00*
	.51	.52	.54	.57	.60	.63	.66	.69	.71	.73	.75	.77	.79	.81	.83	.85	*.87*	*.90*	Div'd Decl'd per sh B ●	*.98*
	2.11	1.59	1.10	1.08	1.11	1.08	1.23	1.44	1.15	1.24	1.29	1.43	1.73	2.09	3.99	2.52	*1.30*	*1.05*	Cap'l Spending per sh	*1.25*
	5.62	5.98	6.23	6.56	6.87	7.16	6.76	7.06	7.29	7.56	7.91	8.30	8.68	9.07	9.44	10.04	*10.60*	*11.35*	Book Value per sh C	*14.25*
	44.44	44.65	44.84	44.90	44.96	45.00	44.48	44.61	44.77	44.78	44.85	44.91	44.93	44.97	44.88	44.99	*45.00*	*45.00*	Common Shs Outst'g D	*45.00*
	7.0	10.4	9.2	9.1	9.3	9.1	10.7	12.5	14.3	12.1	11.6	11.9	12.5	14.4	13.4	13.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
	.57	.71	.62	.76	.70	.68	.68	.76	.84	.79	.78	.75	.72	.75	.76	.86			Relative P/E Ratio	*.95*
	8.1%	6.2%	6.6%	7.0%	7.3%	7.5%	6.4%	5.7%	5.5%	6.2%	6.2%	5.8%	5.8%	5.0%	5.2%	4.4%			Avg Ann'l Div'd Yield	*3.4%*
							337.3	351.6	382.4	379.6	394.4	435.4	456.2	515.2	768.2	820.0	*1150*	*1275*	Revenues ($mill)	*1650*
							44.9	45.2	41.8	45.0	48.7	52.1	52.5	53.8	56.8	69.3	*70.0*	*80.0*	Net Profit ($mill)	*100*
							29.6%	29.1%	31.9%	30.6%	34.1%	33.4%	34.6%	33.1%	32.4%	33.5%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
							2.2%	4.3%	7.3%	5.1%	6.0%	3.3%	1.5%	3.2%	10.6%	12.1%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*6.0%*
							52.9%	46.8%	49.1%	47.2%	47.9%	45.4%	46.2%	43.6%	56.2%	57.9%	*58.5%*	*60.0%*	Long-Term Debt Ratio	*50.5%*
							41.1%	47.4%	45.6%	47.5%	47.1%	49.7%	49.2%	51.9%	41.0%	39.7%	*41.0%*	*38.0%*	Common Equity Ratio	*47.5%*
							732.3	664.0	715.8	712.9	752.5	750.2	792.1	788.2	1032.1	1139.2	*1165*	*1345*	Total Capital ($mill)	*1375*
							851.0	879.0	895.0	912.1	929.5	952.9	1025.6	1089.8	1211.6	1232.8	*1135*	*1015*	Net Plant ($mill)	*600*
							8.0%	8.8%	7.4%	7.9%	8.1%	8.6%	8.1%	8.3%	6.9%	8.3%	*8.0%*	*8.0%*	Return on Total Cap'l	*9.5%*
							13.0%	12.8%	11.5%	12.0%	12.4%	12.7%	12.3%	12.1%	12.5%	14.4%	*14.0%*	*14.5%*	Return on Shr. Equity	*15.0%*
							14.3%	13.7%	12.2%	12.7%	13.2%	13.4%	12.9%	12.7%	12.9%	14.9%	*14.5%*	*15.0%*	Return on Com Equity E	*15.5%*
							4.4%	4.0%	2.5%	3.1%	3.7%	4.2%	3.9%	3.8%	4.2%	6.5%	*5.5%*	*6.5%*	Retained to Com Eq	*8.5%*
							70%	72%	80%	77%	73%	70%	71%	71%	69%	57%	*62%*	*57%*	All Div'ds to Net Prof	*48%*

% TOT. RETURN 8/01

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.4	1.6
3 yr.	55.1	58.0
5 yr.	104.3	87.6

CAPITAL STRUCTURE as of 6/30/01
Total Debt $802.6 mill. Due in 5 Yrs $410.5 mill.
LT Debt $657.1 mill. LT Interest $50.6 mill.
(LT interest earned: 2.7x)
Pension Liability None
Pfd Stock $27.4 mill. Pfd Div'd $1.8 mill.
Includes 274,030 shares 8.125%, each convertible into 4.8 common shares; callable at $100.8125.
Excludes deferred ESOP benefit of $11.6 mill.

Common Stock 44,999,368 shs.
as of 7/31/01

MARKET CAP: $886 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	1998	1999	2000
% Change Retail Sales (KWH)	+7.9	+3.4	+5.5
Avg. Indust. Use (MWH)	3237	3460	3815
Avg. Indust. Revs. per KWH (¢)	4.15	4.21	5.00
Capacity at Peak (Mw)	1793	1879	2787
Peak Load, Summer (Mw)	1627	1767	1839
Annual Load Factor (%)	56.2	54.3	55.4
% Change Customers (yr-end)	+1.7	+1.7	+1.1
Fixed Charge Cov. (%)	329	288	240

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '98-'00 to '04-'06
Revenues	8.5%	12.5%	*15.5%*
"Cash Flow"	4.5%	6.0%	*11.5%*
Earnings	3.5%	5.5%	*8.0%*
Dividends	3.0%	2.5%	*2.5%*
Book Value	3.5%	4.5%	*7.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	97.2	128.3	172.6	117.1	515.2
1999	121.7	222.5	285.0	139.0	768.2
2000	137.1	186.6	269.1	227.2	820.0
2001	253.1	303.7	*325*	*268.2*	*1150*
2002	*275*	*325*	*375*	*300*	*1275*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1998	.14	.31	.48	.19	1.12
1999	.18	.30	.54	.17	1.19
2000	.23	.39	.66	.18	1.46
2001	.25	.29	*.71*	*.20*	*1.45*
2002	*.30*	*.38*	*.73*	*.24*	*1.65*

Calendar	QUARTERLY DIVIDENDS PAID B ● Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1997	.1925	.1975	.1975	.1975	.79
1998	.1975	.2025	.2025	.2025	.81
1999	.2025	.2075	.2075	.2075	.83
2000	.2075	.2125	.2125	.2125	.85
2001	.2125	.2175	.22		

BUSINESS: Cleco Corporation is a holding company for Cleco Utility Group, which supplies electricity to about 250,000 customers in a 14,000-sq.-mi. region in central Louisiana. Through subsidiaries, develops electric & gas assets, markets energy, provides energy services. Electric revenue breakdown, '00: residential, 42%; commercial, 18%; industrial, 16%; other, 24%. Largest industrial customers are paper mills and other wood-product industries. Generating sources, '00: coal & lignite, 36%; gas, 30%; purchased, 34%. Fuel costs: 55% of revenues. '00 reported deprec. rate: 3.3%. Has 1,400 employees. 9,400 common stockholders. President & CEO: David M. Eppler. Inc.: Louisiana. Address: P.O. Box 5000, Pineville, LA 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's nonregulated generating strategy should produce solid earnings growth in 2002. The first phase (150 megawatts) of the Perryville project came on line in mid-2001. This plant will probably provide only a cent or two to share net in the second half of this year, but after the second phase (550 mw) is completed in 2002, Perryville will contribute an estimated $0.12 annually. Another project, under construction, Acadia, should contribute $0.10 a share in 2002 and $0.20 annually beginning the following year. As for 2001, earnings are likely to be flattish because favorable weather patterns lifted share net by $0.10 a year ago. Cleco stock is ranked 4 (Below Average) for Timeliness.

Cleco forms partnerships and arranges tolling agreements in order to lessen the risk of these projects. Under a tolling agreement, a third party is responsible for providing the fuel for the plants and marketing the power they produce. This insulates Cleco and its co-owners from fuel and market risk, though they do assume construction and operating risk. Thus, these investments should provide a steady income stream for Cleco as long as the plants run well.

Cleco is pursuing additional generating projects. It formed an agreement with Mirant, its partner in the Perryville project, to develop over 2,000 mw of generation in the South over the next five years. This would put Cleco close to its goal of controlling 4,000 mw of nonregulated generation by 2005 (versus 1,700 mw in operation or under construction currently).

The regulated utility business is growing by roughly 2%-3% a year. Cleco plans to continue annual dividend growth at a similar pace. The utility's current regulatory agreement, which runs through 2005, provides some stability. It freezes rates over that time, but allows the utility to earn a return on equity of up to 12.625%. In addition, it appears as if no major regulatory restructuring will occur in Louisiana, though large industrial customers might win the right to choose their electric supplier beginning in 2003.

Cleco stock offers an average yield by utility standards. Its 3- to 5-year total-return potential is modest.

Paul E. Debbas, CFA *October 5, 2001*

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	90

(A) Primary EPS through '96, diluted thereafter. Excl. nonrecurring gains: '86, 7¢; '00, 5¢; loss from discontinued operations: '00, 14¢. Next earnings report due early Nov. (B) Next div'd meeting about Oct. 26. Goes ex about Oct. 31. Div'd payment dates: 15th of Feb., May, Aug., Nov. ● Div'd reinv. plan avail. (C) Incl. deferred charges. In '00: $162.0 mill., $3.60/sh. (D) In mill., adj. for splits. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '96: 12.625%; earned on avg. com. eq., '00: 15.0%. Regulatory Climate: Below Average.

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To subscribe call 1-800-833-0046.

Exhibit____(CWK-3R)

Montana-Dakota Utilities - Discounted Cash Flow Update

		Zacks g	50-Day Price	Dividend	Div*1.5g	Dividend Yield	DCF Return	DCF Return August, 01
Electric-only Utilities								
Florida Power & Light	FPL	7.18%	$55.49	$2.24	$2.32	4.18%	11.4%	11.2%
Pinnacle West	PNW	8.86%	41.28	1.60	1.67	4.05%	12.9%	12.4%
Southern Company	SO	5.34%	24.22	1.34	1.38	5.68%	11.0%	11.7%
Great Plains Power	GXP	6.00%	24.62	1.66	1.71	6.94%	12.9%	12.9%
							12.1%	12.1%
Combination Gas/Electric Utilities								
Ameren	AEE	4.43%	$41.84	$2.54	$2.60	6.21%	10.6%	11.1%
DPL Inc	DPL	10.00%	20.92	0.88	0.92	4.42%	14.4%	13.4%
Progress Energy	PGN	6.23%	43.61	2.13	2.20	5.04%	11.3%	12.2%
Puget Sound Energy	PSD	5.33%	21.32	1.84	1.89	8.86%	14.2%	12.9%
Sierra Pacific	SRP	4.75%	15.12	0.87	0.89	5.89%	10.6%	10.4%
Empire District	EDE	n.a	20.82	1.28				
Consolidated Edison	ED	3.94%	39.79	2.22	2.26	5.69%	9.6%	9.6%
Energy East	EAS	5.75%	19.10	0.96	0.99	5.17%	10.9%	11.1%
Alliant	LNT	5.00%	29.69	2.00	2.05	6.90%	11.9%	8.9%
							11.7%	11.2%

ADAMS COUNTY RECORD
AFFIDAVIT OF PUBLIC

STATE OF NORTH DAKO

COUNTY OF ADAMS)
Carole Rosencrans

says: That she is the secret
general circulation published in
newspaper is now the official n
the time hereinafter mentioned a
MDU annual repo
printed copy of which is hereunto
said newspaper during the perio
newspaper proper, and not in a s
for 1 consecutive wee

Straight Matter Lines
First Time Line Rate $.53
Subsequent Line Rate $.53

Column Inches
First Time Inch Rate $5.00
Subsequent Inch Rate $5.00

Notary Fee:
Carole Rosen

Sworn and subscribed to before

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report
Case No. PU-399-01-186
NOTICE OF HEARING, NOTICE OF PUBLIC INPUT SESSIONS, AND NOTICE OF INTERVENTION DEADLINE
November 21, 2001

On September 7, 2001, the North Dakota Public Service Commission received a complaint from the North Dakota Public Service Commission Staff (Staff) alleging that Montana Dakota Utilities Co. (MDU), is recovering more revenue than necessary to earn a reasonable return on its investment in North Dakota to provide electric utility service. Staff alleges that MDU's electric service rates should be changed to reduce annual revenue by $9.155 million..

On September 19, 2001, the Commission found that the Staff's Complaint states a prima facie case and that the Complaint should be served on MDU. The Commission believes the public interest requires the Staff's Complaint be investigated. Issues to be considered include:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is MDU's rate of return on its property, used and useful, for the service and convenience in North Dakota?
3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are MDU's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Other relevant information or proposals concerning the proceeding.

A public hearing on this matter will be held beginning February 25, 2002 at 9 a.m. (CST) in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. Anyone wishing to become a party to this proceeding must file a Petition to Intervene by January 25, 2002.

Public input sessions will be held via interactive television on December 11, 2001 at 12:30 p.m. (CST) at locations set forth below. Members of the public are invited to appear and participate in the informal discussions. The meetings are not considered part of the technical hearing and the discussion at the meetings will not become part of the evidence reviewed by the Commission in making its decision. The discussion will, however, aid the Commission and its staff in identifying the areas of concern to the members of the public.

Bismarck State College
Vocational Technical Ctr Rm 228
1200 College Dr
Bismarck ND

University of North Dakota
Creighton Bldg Rm 109
1410 University Ave
Williston, ND

Dickinson State University
North Campus Rm 104
1679 6th Ave W
Dickinson, ND

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Jon H. Mielke, Executive Secretary, at least 24 hours prior to the hearing.

PUBLIC SERVICE COMMISSION
Anthony T. Clark, Commissioner
Susan E. Wefald, President
Leo M. Reinbold, Commissioner

My Commission expires March 29, 2006

Notary Public, State Of North Dakota
Commission Expires March 29, 2006

52 **PU-399-01-186** Pages: 1

Affidavit of Publication

by Adams County Record

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

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

RECEIVED
JAN 11
EXECUTIVE SECRETARY

January 11, 2002

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-01-186

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of the direct testimony and exhibits of its witnesses in the above referenced case.

Attached is the testimony of Mr. C. Wayne Fox, Mr. J. Stephen Gaske, Mr. Terry L. Blinsky, Mr. Gerald L. Gress, Mr. Donald R. Ball, and Ms. Rita A. Mulkern.

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

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

Attachments
c: D. Schulz

EXHIBIT
6
2/25/02

51 PU-399-01-186 Pages: 1

Cover letter re direct testimony

by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 6
01/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
C. Wayne Fox

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

A. Yes, my name is C. Wayne Fox. 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 President of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

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

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

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

A. In 1964, I received a Bachelor of Science degree in Electrical Engineering from Chicago Technical College, Chicago, Illinois. I received a Master of Arts degree in Business Administration from the University of Illinois, Springfield, Illinois, in 1975. Upon graduating from college in 1964, I joined the Illinois Commerce Commission, the state body regulating public utilities in Illinois, as an electrical engineer. Upon termination of my employment with the Illinois Commerce Commission in June 1980, I was

EXHIBIT
6
2/28/02

50 PU-399-01-186 Pages: 9
Direct Testimony of C Wayne Fox
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 6
01/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike

serving as Manager of the Public Utilities Division. In that capacity, my duties included testifying in formal cases before the Commission, formulating and coordinating Commission policies on technical and administrative matters, processing formal and informal cases, and advising the Commission on matters related to the regulation of public utilities operating in the state of Illinois.

In June 1980, I joined Montana-Dakota as Assistant Treasurer - Regulatory Affairs, retaining that position until May 1982 when I was elected Assistant Vice President - Regulatory Affairs. In May 1985, I was promoted to Vice President - Regulatory Affairs. In May 1987, my duties were broadened to include the Company's purchasing and general services activities. At that time, my title was changed to Vice President - Regulatory Affairs and General Services. I assumed my present position in August 2000.

I also have served on several committees of the Electric Power Research Institute and the Edison Electric Institute.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously sponsored testimony before this Commission, the Montana Public Service Commission, the Wyoming Public Service Commission, the Minnesota Public Utilities Commission and the South Dakota Public Utilities Commission.

In addition, during my tenure with the Illinois Commerce Commission, I testified in a number of cases before that Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's position regarding the North Dakota Public Service Commission Staff's (Staff) recommendation for an electric rate decrease and to introduce the other witnesses who will sponsor testimony on behalf of Montana-Dakota.

Q. What is the Company's position with respect to the Staff recommendation?

A. It is our position that Montana-Dakota's current electric rates are just and reasonable and should not be reduced at this time. My testimony, along with that of other witnesses, will show that no rate reduction is warranted at this time. The Staff case does not take into account a number of necessary adjustments in making an appropriate determination regarding the reasonableness of the existing electric rates. Our testimony will address the necessary adjustments.

Q. When was the last electric general rate change for Montana-Dakota?

A. Montana-Dakota's electric rates were last changed in February 1987.

Q. Would you please explain how Montana-Dakota has been able to hold its electric rates flat since 1987?

A. From 1987 to 2001 the consumer price index has risen 59%. In spite of this significant increase, we have been able to hold our electric rates flat for this entire period by finding ways of operating our business more efficiently and taking advantage of new technologies where it makes economic sense to do so, while maintaining a consistent focus on providing safe, reliable electric service to our over 70,000 electric customers in North Dakota at reasonable and competitive prices. Let me give you a few examples of what we did.

- ✓ We implemented a new Customer Information System to streamline our billing and record keeping processes to operate more efficiently and keep costs down.
- ✓ We implemented a computerized dispatching system that saves about an hour a day of a service person's time by having a computer in the service vehicle with the day's work orders which enables us to directly dispatch orders electronically. This results in efficiencies and less paper work. An hour a day of an employee's time translates to a significant benefit and we expect to improve on this in the future.
- ✓ We have implemented a customer service center where all calls for service related matters come into a central location, saving time and personnel requirements. The centralized call center also allows employees to handle multiple subject matters with customers and allows us to tie into the computerized dispatching system for faster and better customer service.
- ✓ We continue to participate in joint trenching with others to minimize the cost of extending our lines to new customers.
- ✓ We have combined our gas meter testing into one facility that handles our testing program on a company-wide basis. This allows for more specialized testing equipment, increasing meter testing throughput.
- ✓ Implemented itron meter reading system, which loads the read data directly into our customer records without manual key punching.

- ✓ We are using joint meter reading with others to minimize costs. Currently we read the water meters for the cities of Richardton and Wildrose for a fee and we are looking for other opportunities to reduce the costs for our customers in this area.
- ✓ We are currently developing a geographic information system (GIS) where all of our maps will be converted to electronic format. This will provide easier and quicker updating of system changes, and improved access to the information by all users, resulting in time saving and other efficiencies.

In addition to the above, we also continue to look for other opportunities to reduce costs and increase efficiencies.

Q. Has Montana-Dakota earned its authorized return level in each of the years since 1987?

A. No, it has not. In the years since 1987 our earnings have sometimes been below the authorized level set by the Commission and sometimes above that level. A regulated utility, on average and over time, should be able to earn at or near its authorized return level. I should note that we did not seek a rate increase in those years in which our earnings fell short of reaching the authorized level set by the Commission. Our efforts to achieve efficiencies have been beneficial to our customers and our shareholders by providing rate stability in an increasing cost environment while providing adequate returns to attract investment, maintaining a financially viable utility and providing the necessary service.

Q. Is a regulated public utility such as Montana-Dakota guaranteed a reasonable return on the investment it has made in facilities to provide safe and reliable electric service?

A. No. A regulated public utility is only afforded an opportunity to earn a reasonable return on its investment in facilities dedicated to public utility service. There is no guarantee.

Q. Did the earned returns for the period 1997 through 2000 exceed the authorized return level?

A. Yes, they did.

Q. Would you explain the reason for the return levels in these years?

A. Yes. The earned return levels for this period were caused primarily by a single element, the selling of power in the wholesale market as the opportunities arose. It was a market anomaly that afforded us, and other utilities across the country, the ability to temporarily obtain significantly increased revenues and margins from sales of electric energy into the wholesale market in the last few years. I should note that, had we only been able to make these sales at the historic levels, the Company would have earned less than its authorized return, holding all other things constant. This is shown graphically on Exhibit No. ___ (CWF-1).

Q. Do those same opportunities currently exist in the wholesale market?

A. No. Those opportunities, we believe, peaked in 2001 and will be significantly reduced in the current year (2002) and beyond. The reasons for the loss of opportunities are described in the testimony of Mr. Blinsky,

Montana-Dakota's Electric Bulk Power Marketing Coordinator. In short, the opportunities to obtain higher prices for wholesale power no longer exist in the current market.

Q. What does this mean for Montana-Dakota?

A. What this means for Montana-Dakota is that we will no longer be able to sell as much power in the wholesale market and what we do sell will not be at the higher prices we have seen in the past few years. This translates to a significant downturn in our earnings. The ability to make wholesale sales at higher prices was the primary reason that we exceeded our authorized return for the period in question. Absent these market opportunities, our returns will be significantly reduced. The effect of this on our earnings will be quantified by other witnesses.

Q. Are there factors other than the lack of wholesale sales opportunities that lead you to conclude that no electric rate reduction is appropriate at this time?

A. Yes, there are. In addition to the wholesale sales levels, there are a number of other changes in cost levels from the year 2000 basis used by the Staff that the Commission needs to take into consideration in determining the reasonableness of our electric rates. These known and measurable changes will be discussed in detail by other witnesses.

Q. Would you please summarize the Company's position?

A. The current rates for the North Dakota electric operation, given the changes described for the wholesale electric market, the other known and measurable changes and the current capital costs described by Montana-

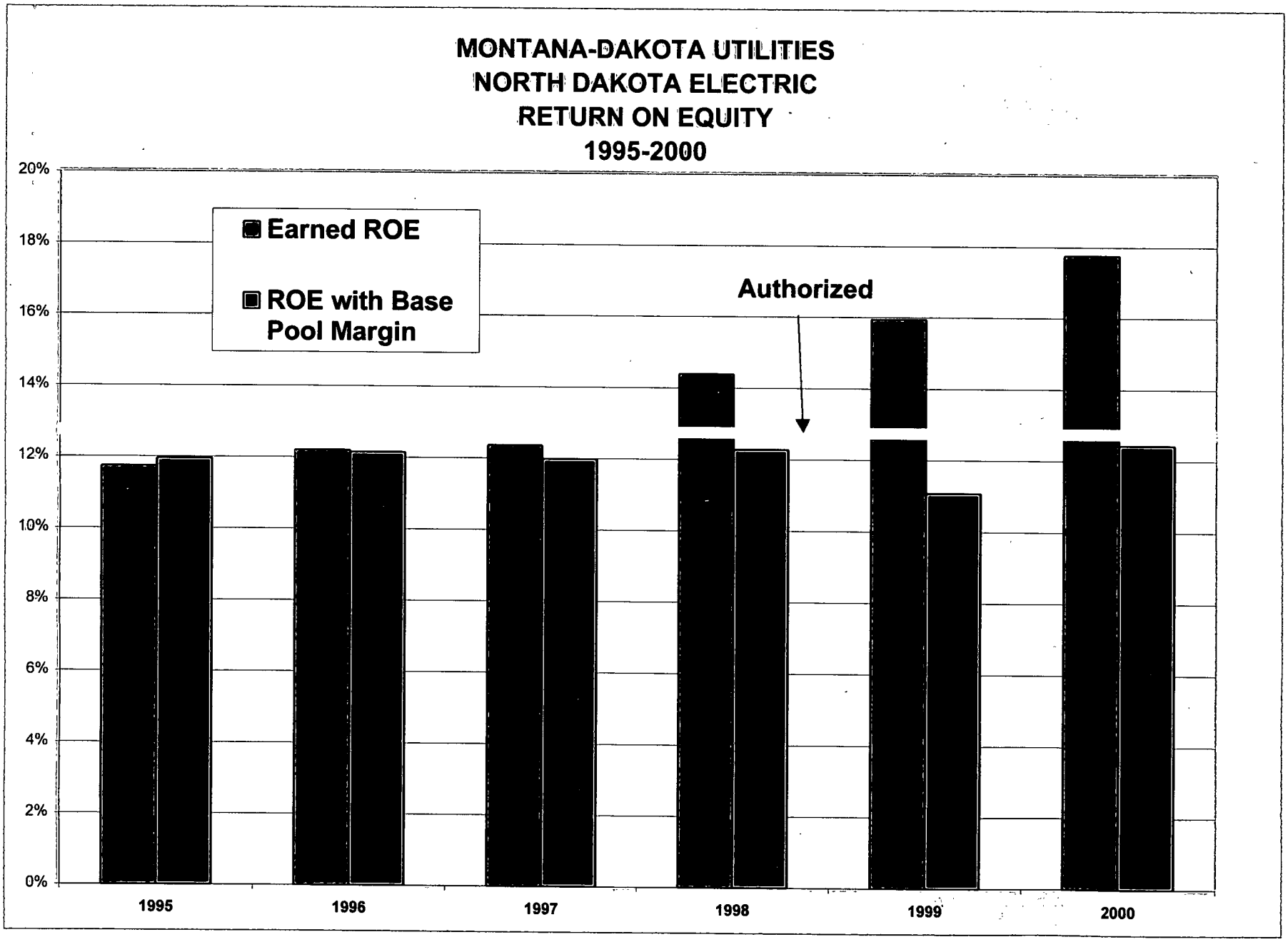
Dakota's witnesses, are just and reasonable and in the public interest. In fact, as shown on Ms. Mulkern's exhibit, there is a revenue deficiency of $710,000. When we also consider the added costs expected in the near future for the new turbine described by Mr. Gress, it would make no sense whatsoever, in my view, to reduce rates now only to raise them in the very near future.

Q. Will you please identify the other witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes. In addition to myself, Mr. J. Stephen Gaske, President of Zinder Companies, Inc., will testify regarding the appropriate cost of common equity and overall cost of capital for Montana-Dakota's electric operations. Mr. Terry L. Blinsky, Electric Bulk Power Marketing Coordinator for Montana-Dakota, will testify regarding the wholesale power market and the appropriate level of wholesale sales given current conditions in the wholesale market. Mr. Gerald L. Gress, Power Production Manager for Montana-Dakota, will testify regarding required additional generation related expenditures. Mr. Donald R. Ball, Director of Regulatory Affairs for Montana-Dakota, will testify regarding certain known and measurable adjustments. Ms. Rita A. Mulkern, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirements necessary for Montana-Dakota's North Dakota electric operations.

Q. Does this complete your testimony?

A. Yes, it does.



Case No. PU-399-01-186
Exhibit No. _____(CWF-1)
Page 1 of 1

Exhibit No.___(JSG-1)

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

DOCKET NO. PU-399-01-186

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7720 Wisconsin Avenue, Suite B-102 Bethesda, MD 20814.

Q2. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also received a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. In 1980 and 1981, I was employed by Olson and Company where my primary duties were to assist in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as

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by Montana-Dakota Utilities Co., a Division of MDU R
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assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates as a consultant. I have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than twenty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, and market power. I also have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil pipeline operations before six state regulatory bodies including North Dakota. In addition, I have testified on rate design and pricing issues before the Maine Public Utilities Commission, the Iowa Utilities Board and the Postal Rate Commission, and on issues related to generating plant economics before the Wisconsin Public Service Commission. I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals course. Finally, I am a member of the American Economic Association and its Transportation and Public Utilities Group, the Financial Management Association, and the AGA Rate Committee.

I. INTRODUCTION

Scope and Overview

Q3. What is the scope of your testimony in this proceeding?

A. This proceeding arises out of a complaint that was filed by the Staff of the North Dakota Public Service Commission ("PSC"). In this complaint, the PSC Staff contends that the Montana-Dakota Utilities Co. ("Montana-Dakota") electric generation, transmission and distribution operations in the state of North Dakota are collecting excess revenues of approximately $9.155 million. I have been asked by Montana-Dakota to evaluate the required overall rate of return for the company's electric distribution operations in the state of North Dakota and to evaluate the rate of return study filed by Charles W. King on behalf of the Staff of the North Dakota PSC on August 31, 2001.

Q4. Would you please summarize your testimony?

A. Mr. King has recommended that Montana-Dakota be allowed a return on common equity of only 11.2 percent and an overall rate of return on rate base of 9.67 percent. However, a review of Mr. King's cost of capital study reveals that he has excluded several of the most relevant proxy companies from his return on equity study and used a proxy group of companies that is inappropriate for estimating the rate of return for the Montana-Dakota electric operations. In addition, the allowed rate of return for a regulated public utility requires a flotation cost adjustment in order to meet the standard that the return is sufficient to attract capital on reasonable terms. By excluding such an adjustment Mr. King's recommendation falls short of

the return that investors require to invest in Montana-Dakota's North Dakota electric operations. In this Direct Testimony, I calculate the cost of common equity capital for Montana-Dakota's electric operations based on a Discounted Cash Flow ("DCF") analysis of a group of companies that are more nearly similar to Montana-Dakota's electric operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

In addition, Mr. King has incorrectly calculated the cost of debt. My Direct testimony presents the correct calculation of these values and discusses the precedents for the calculation methods used by Montana-Dakota.

Q5. What rate of return is Montana-Dakota requesting in this proceeding?

A. Based on its test period capital structure, as shown in the testimony of Mr. King, Montana-Dakota is requesting the following rate of return:

Source	Amount (000s)	Percent	Cost	Overall Rate of Return
Long-Term Debt	$144,894.0	45.90%	9.22%	4.23%
Preferred Stock	$16,500.0	5.23%	4.63%	0.24%
Common Equity	$154,250.0	48.87%	12.75%	6.23%
TOTAL	$315,644.0	100.00%		10.70%

As my testimony discusses, an overall allowed rate of return of 10.70 percent, with a 12.75 percent return on common equity, represents the cost of capital for Montana-Dakota.

Company Background

Q6. Would you please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.?

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

In 2000, Montana-Dakota served a total of 115,000 residential, commercial and industrial customers. As shown on Exhibit No. ___ (JSG-2), Schedule 4, page 1, Montana-Dakota's electric utility assets comprised 13.2 percent of MDU Resources' total assets. In addition, the electric utility revenues and operating income accounted for 8.6 percent and 17.9 percent of MDU Resources' total, respectively. North Dakota accounted for 60 percent of the electric utility operating revenues, while Montana (23 percent), South Dakota (7 percent) and Wyoming (10 percent) accounted for the other 40 percent of electric utility revenues.

Most of Montana-Dakota's generation is derived from four coal-fired steam turbine generating stations. In addition, it has three combustion turbine

peaking stations. The total generating capacity owned by the company is approximately 400 Mw.

II. FINANCIAL MARKET STUDIES

Criteria for a Fair Rate of Return

Q7. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944)).* There the Court described the relevant criteria as follows:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That

> return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;

2. sufficient to maintain the financial integrity of the regulated company; and,

3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q8. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

Q9. How are the costs of preferred stock and long-term debt determined?

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

Q10. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For

example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches are described later in this testimony.

Cost of Debt

Q11. In estimating the cost of capital for Montana-Dakota in this proceeding, Mr. King has added together the interest rate plus the non-cash issuance cost amortization and divided that sum by the net unamortized balance of the debt issues. Is this the appropriate method for estimating the cost of debt for ratemaking purposes?

A. No. Mr. King's accounting-based approach understates the effective cost of debt. In addition, Mr. King is wrong in asserting that the FERC requires his approach for ratemaking. Instead, although for *accounting* purposes the FERC typically requires a straight-line amortization of issuance costs to allocate debt

issuance costs to each year that the debt is outstanding, the FERC requires a yield-to-maturity approach for estimating the cost of debt for *ratemaking* purposes.

Q12. Would you please describe the correct method for calculating debt costs?

A. The correct method for calculating total debt costs is to use the "Yield-to-Maturity" method (which may also be referred to as the Internal Rate of Return ("IRR") method) that Montana-Dakota used in its Data Response No. 9 to Mr. King's Data Request dated July 19, 2001. This data response, which shows Montana-Dakota's calculation of cost for each of its long-term debt issues, is included as an attachment to Mr. King's testimony. A summary of the costs for each debt issue is shown on Exhibit No. ___(JSG-2), Schedule 1. By calculating the effective cost of debt based on the actual amounts and the actual timing of cash flows, the "Yield-to-Maturity" method provides an accurate calculation of the true cost of each debt issue.

Q13. Why is Mr. King's accounting-based approach inaccurate?

A. There are three major problems with Mr. King's accounting-based approach:

1. It incorrectly assumes that interest is paid only at the end of each year when, in fact, it is paid semi-annually.

2. For purposes of estimating the amount of funds available to the issuer, Mr. King's approach incorrectly assumes that the issuer does not pay issuance expenses, discount expenses, and associated losses on redemption of debt until the final year when the principal is repaid. However, those expenses are paid at the time the debt is issued and therefore reduce the net proceeds available to the issuer.

3. For purposes of estimating the timing of cash payments for issuance expenses, discount expenses and associated losses on redemption of debt, Mr. King's approach incorrectly assumes that the issuer does not make these cash

payments until the years in which an amortization expense is recorded in the accounting records. However, those expenses actually are paid at the time the debt is issued and therefore generally occur long before any of the non-cash, annual amortization entries are recorded for accounting purposes.

Each of these flaws causes Mr. King's accounting-based approach to understate the cost of long-term debt.

Q14. At page 7, line 26 to page 8, line 4 of his testimony, Mr. King cites the Federal Energy Commission's accounting and reporting requirements for "Long-Term Debt: Premium, Discount and Expense, and Gain or Loss on Reacquisition" as the reason that he thinks Montana-Dakota has calculated debt cost incorrectly. This citation also provides the basis for his calculation of debt costs. Has he cited the correct section of the FERC's regulations for electric companies?

A. No. Mr. King has mistakenly relied upon accounting rules that appear in Subchapter C, Part 101 ("Uniform System of Accounts Under the Federal Power Act"), of the FERC's rules and regulations. Those accounting rules do not prescribe or require any calculation of the effective annual percentage cost of debt. Instead, the pertinent FERC rules for calculating debt costs for ratemaking purposes appear in Subchapter B, Part 35 ("Filing of Rate Schedules"). Therein, at §35.13 (h), (22), (ii), (B), (6) the FERC prescribes the following method for calculating the cost of debt for ratemaking purposes:

> *"Cost of Money, which is the* ***yield to maturity at issuance based on the interest rate and net proceeds to the utility*** *determined by reference to any generally accepted table of bond yields."* (Emphasis added).

In other words, for ratemaking purposes, the FERC requires utilities to calculate the cost of debt using the method employed by Montana-Dakota.

Q15. Do you disagree with other aspects of Mr. King's debt cost calculation?

A. Yes. The commitment fees on lines of credit are a relevant cost given the components of the capital structure that Mr. King has chosen to include. Consequently, the cost of commitment fees is included in the debt cost calculation in Schedule 1 of Exhibit No. ___(JSG-2).

Q16. What debt cost rates have you used for Montana-Dakota?

A. Calculation of the overall cost of long-term debt and the effective cost of each of the long-term debt issues is shown on page 2 of Schedule 1. For purposes of this proceeding, Montana-Dakota accepts the debt components and capital structure proposed by Mr. King. However, as I have shown, Mr. King has incorrectly calculated the cost of the debt. Schedule 1, page 1 of Exhibit No. ___(JSG-2), shows that the correct calculation of overall average debt costs for Montana-Dakota results in a cost of 9.22 percent.

Q17. What cost of preferred stock did you use?

A. Montana-Dakota's annual cost of preferred stock is 4.632 percent.

Interest Rates and the Economy

Q18. What are the general economic factors that affect the cost of capital?

A. Investors are often influenced by their perceptions of the economy and both short- and long-term trends. Page 1 of Schedule 2 of Exhibit No.___(JSG-2) shows various general economic statistics. The economy has had a record of persistent

growth during the past thirty years, with only temporary recessionary periods. Real growth in the Gross Domestic Product ("GDP") has averaged 3.2 percent annually during the past 30 years, 3.1 percent for the past 20 years and 3.2 percent for the past ten years. However, in recent months the economy has been shrinking and is in a recession. A significant decline in stock market prices in recent months is partially the result of an increase in the perceived risk of equity investments at this time.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 3.0 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.3 percent.

Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates provide a standard measure of returns currently available on less risky securities. As Page 2 of Schedule 2 of Exhibit No. ___(JSG-2) shows, long-term interest rates have remained relatively stable during the past two years. The recent yields on A-rated public utility bonds have been approximately 7.6 percent and the yields on Baa-rated public utility bonds have been approximately 8.0 percent.

Discounted Cash Flow ("DCF") Method

Q19. Please describe the DCF method of estimating the cost of common equity capital.

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

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

Q20. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of

future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D\,(1 + .625g)}{P} + g \qquad (1)$$

where:

K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

Flotation Cost Adjustment

Q21. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Schedule 5 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 15 new common stock issues by electric companies between 1996 and 2000. Flotation costs associated with these new issues averaged 4.62 percent. This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 4.75 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.0475.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even

when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

DCF Study of Electric Utility Companies

Q22. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity?

A. Because Montana-Dakota must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's electric operation as a stand-alone company is not possible. To get around this problem, I have used a proxy group of companies that is most nearly similar in risk to the regulated electric utility operations of Montana-Dakota. Consequently, like Mr. King, my estimate of the rate of return which investors require for Montana-Dakota is primarily determined by conducting market-based DCF analyses of a group of publicly-traded electric utility proxy companies with a range of risks that includes

risks that are comparable to the risks of Montana-Dakota's operations. These analyses of a group that includes comparable companies suggest the level of returns that is appropriate for Montana-Dakota's North Dakota electric operations.

Q23. How did you begin the process of selecting your group of proxy companies?

A. I started with the two lists of companies examined by Mr. King. In his testimony, Mr. King presents two groups of companies that he analyzed separately for purposes of setting an allowed rate of return for Montana-Dakota's North Dakota electric utility operations.

First, he presented a list of vertically-integrated companies engaged in electric generation, transmission and distribution operations that also meet two criteria: (i) they have investment-grade bond ratings; and, (ii) they have total revenues in excess of $100 million. From this list, he chose companies that derived at least 85 percent of their revenues from electric operations.

Mr. King also selected a second list of Combination companies with investment-grade bond ratings and revenues in excess of $100 million that are engaged in both electric and gas distribution operations. For this group of companies, he selected those that had combined electric and natural gas revenues that made up at least 85 percent of their total revenues. In other words, a majority of the companies in this second group derived less than 85 percent of their revenues from electric operations, and several of Mr. King's Combination companies even derived less than 75 percent of their revenues from electric operations. Nevertheless, because they also were engaged in natural gas distribution operations, he included them in a group of proxy companies.

Q24. Which of his two groups of proxy companies formed the basis for Mr. King's recommended rate of return for Montana-Dakota's electric operations?

A. Because, according to his DCF analyses, the Combination companies selected by Mr. King had a lower average required rate of return (11.2 percent) than the electric-only companies (12.0 percent), Mr. King concluded that there were significant differences in risks between combination companies and electric-only companies.

Based on this first conclusion, Mr. King next concluded that, since Montana-Dakota has natural gas distribution operations as well as electric operations, the allowed rate of return for its electric operations should be less than the rate of return indicated by his study of electric-only companies.

As a result of these two unsupported conclusions, Mr. King decided to ignore the electric-only group of companies in estimating the required rate of return for Montana-Dakota's electric operations. Instead, he advocates the use of the results of his study of Combination companies and recommends an allowed return on common equity of 11.2 percent.

Q25. Do you agree with Mr. King's method of selecting companies that are supposedly comparable in risk to Montana-Dakota's North Dakota electric operations?

A. No. For purposes of setting an allowed rate of return for electric operations, the appropriate proxy group is one that is primarily engaged in electric operations. Mr. King's reason for rejecting the use of electric-only companies is incorrect and unsupportable for several reasons. First, his conclusion that a

significant difference in risk exists between the Combination companies and the electric-only companies is incorrect. Therefore, his basis for rejecting the use of electric-only companies in setting a rate of return for electric operations is unsupportable. Second, Mr. King's choice of proxy companies is based primarily on the fact that MDU Resources also owns natural gas distribution operations. However, that fact should be irrelevant to this proceeding. The allowed rate of return for Montana-Dakota's electric operations should reflect the risk of those operations on a stand-alone basis. Third, it is inherently illogical to *reject* companies like Southern Company and Kansas City Power & Light which derive 98 and 95 percent of their revenues from electric operations, and replace them with companies like Alliant Energy and Energy East which each derive 68 percent of their revenues from electric operations.

Q26. Would you please elaborate on why Mr. King is incorrect in asserting that a distinction should be made between electric-only companies and Combination electric and gas companies?

A. In addition to the common logic of including electric-only companies in the sample group, there is a simple test for determining whether a statistically significant difference exists between two sample groups. Mr. King has concluded that because the average rate of return results are different for the two groups in his analysis, there must be a fundamental difference in risk between the two groups. However, the simple fact that there is a difference in the average for the two groups does not, by itself, suggest that the two groups have fundamentally different characteristics. Virtually any two groups that are selected are bound to have different average

returns as a result of essentially random effects on the various companies in each group. A valid, simple statistical test considers three factors:

1) Whether a difference in the averages exists;

2) The magnitude of the difference in the averages; and,

3) The variation in the returns for the two sample groups.

Mr. King has considered only the first of these three factors and has ignored the second and third factors. For example, close examination of the variance of returns in the two groups shown in Table 7 of page 18 of Mr. King's testimony suggests substantial overlap between the two groups. FPL Group, one of the supposedly "high risk" electric-only companies has a lower return than several of Mr. King's supposedly "low-risk" combination companies. Similarly, some of the companies in the supposedly "low-risk" combination company group have returns that are as high as, or higher than the returns of any of the supposedly "high-risk" electric companies.

Q27. Would you please describe the analysis that you performed to determine whether Mr. King's DCF results lead to the conclusion that there is a statistically-significant difference between the electric companies and the combination companies that he analyzed?

A. I have applied a common statistical test to determine whether a statistically significant difference exists between Mr. King's two groups of companies. This test incorporates all three of the factors discussed above in order to generate a probability that the averages for the two groups are sufficiently different so as to allow a conclusion that the difference in averages is statistically significant. It is common to

set a probability of five percent or less as the cutoff for accepting an hypothesis. In other words, a statistically-significant difference generally would require that there be a confidence level of 95 percent or more that the difference in means is greater than zero. However, as shown on Exhibit No. ___ (JSG-2), Schedule 3, Mr. King's DCF results indicate a probability of at least 11.7 percent that there is no difference in the average returns for the two groups of companies. Since the 11.7 percent level of significance exceeds the five percent cutoff, the difference in the average returns estimated by Mr. King for the two groups is not statistically-significant. Instead, there is a reasonable probability that the difference in means is the result of random variations in the outcomes for the two groups.

Q28. If Mr. King's DCF results do not indicate a statistically-significant difference in means, is it valid to exclude the electric-only companies from consideration in setting the allowed rate of return for Montana-Dakota's electric operations?

A. No. As I have shown, Mr. King's stated reason for assuming that the combination companies have lower risk than the electric companies cannot be supported conclusively. More important, however, is the fact that the most appropriate group for estimating the return for Montana-Dakota's electric operations is a group that is selected based on the fact that a large percentage of its revenues, assets or operating income are associated with electric operations.

Q29. If there were a statistically-significant difference in average DCF results between the electric and combination companies used by Mr. King, would that fact be a sufficient reason for excluding electric companies and using combination companies instead?

A. No. The purpose of this proceeding is to establish rates for Montana-Dakota's electric operations. However, Mr. King decided to use combination companies and exclude electric-only companies because Montana-Dakota is engaged in both electric and natural gas operations. He asserts that companies engaged in both lines of business have lower risks and that combination companies should be used because:

> *"As a heating source, electricity and gas are to great extent competitors. When a company offers only electric service, it faces the competition of a gas utility and the consequent uncertainties as to market penetration. But when it offers both gas and electricity, it has a reasonable guarantee that regardless of changes in heating technology or consumer preference, it will control the most of the market for heating fuels. Its business risk is therefore lower. For this reason, the most comparable group of utilities to MDU is the combination electric and gas companies."* (Direct Testimony of Charles W. King, page 23, lines 3-9).

Mr. King's analysis is flawed in several respects. Although electric and gas may compete for some heating load, the primary uses of these two forms of energy are fundamentally different. Montana-Dakota's natural gas distribution system is primarily used to provide heat and is not used to provide lighting or to run appliances such as televisions, computers, dishwashers, etc. Similarly, its electric system is not primarily used to heat homes, offices and schools and essentially has significant heating load only in those small communities and rural areas where natural gas is not available. The differences in the primary uses of the two forms of

energy is sufficiently great that the level of direct competition is a minor part of both operations. Therefore, although some degree of inter-energy competition exists between gas and electricity, such competition is very minor, especially for electric operations.

Much more importantly, to the extent that inter-energy competition exists, a company does not reduce the risk of investing in electric facilities merely by owning natural gas distribution operations. When given a choice of heating sources people will choose between gas and electricity based on the relative economics of each energy source. In the long run, Montana Dakota has very little ability to control the relative level of fuel costs and the cost and efficiency of heating appliances that use the different energy sources. Thus, Montana Dakota is limited in its ability to induce people to select one heating source over another. Montana-Dakota's investments in electric facilities would face the same level of risk regardless of whether Montana-Dakota also owned natural gas distribution operations.

While Mr. King is undoubtedly correct in assuming that a diversified parent company can face less risk than each of its subsidiary operations individually, he is wrong in suggesting that such parent-company diversification reduces the risk of investing in any individual operation. For example, if there is a sudden change in the market that causes people to convert large amounts of load from electricity use and switch to natural gas, the value of Montana-Dakota's electric operations would be impaired regardless of who owns the natural gas distribution system. The same would be true for any electric or combination company.

Thus, even if it could be shown that combination companies face less risk than electric-only companies, that fact would not suggest that the electric operations of diversified combination companies face less risk than the electric operations of electric-only companies.

Q30. How did you select a proxy group that adequately reflects the risks of Montana Dakota's electric operations?

A. I started by combining Mr. King's two groups of companies. According to Mr. King, these companies were selected by him in part because they still have vertically-integrated electric generation, transmission and distribution operations. I then selected all companies that derived at least 75 percent of their revenues from electric operations. Unlike Mr. King, I included companies that derive large amounts of revenue from electric operations, but do not have natural gas distribution operations. In addition, unlike Mr. King, I excluded companies that had less than 75 percent of their revenues associated with electric operations, even if they also had natural gas distribution revenues. The goal was to select *all* companies on the list that derived at least 75 percent of their revenues from regulated electric operations. Both Mr. King and myself excluded Empire District Electric because analysts' forecasts of growth for that company were not available. As shown on page 1 of Exhibit No. ___ (JSG-2), Schedule 3, there are 12 companies that fit the required criteria. It should be noted that Kansas City Power & Light, one of Mr. King's companies, recently formed a holding company and changed the name of the publicly-traded company to Great Plains Energy, Inc. Consequently, Great Plains

Energy in my exhibits is essentially the same as Kansas City Power & Light in Mr. King's exhibits.

Q31. How did you calculate the dividend yields for the companies in your comparison group?

A. These calculations are shown on page 3 of Schedule 4 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from June 2001 to November 2001. The dividend yields were calculated for each company by dividing the indicated annual dividend by the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

Q32. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies?

A. I developed three different DCF analyses of the proxy companies based on three different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach I calculated a DCF rate of return using a combination of securities analysts' growth projections and the Value Line retention growth forecasts to produce a Second-Stage Retention Growth analysis. As a second approach, I conducted a Basic DCF analysis that relied solely on the analysts'

forecasts for the growth rate component of the model. Finally, my Primary DCF uses a variety of sources and analyses to develop an estimate of the composite growth rate that investors would expect from the sample group of proxy companies.

Second-Stage Retention Growth Analysis

Q33. How did you use your Second-Stage Retention Growth analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Second-Stage Retention Growth rate approach combines: (i) estimates of long-term growth for each company that are published by various investment analysts and (ii) Value Line retention growth forecasts.

Q34. How did you estimate the first stage of expected future growth?

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. As shown on Exhibit No. ___ (JSG-2), Schedule 4, page 5, the average of the analysts' long-term growth rate estimates for the electric utility proxy companies is 7.0 percent.

Q35. Would you please describe the second stage, retention growth rate component of your analysis?

A. In addition to analysts growth rate forecasts, I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although

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

Q36. How can a company's earnings retention rate affect its future growth?

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

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

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

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

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

Q37. How did you calculate the expected future retention rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected for several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 4 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 6.0 percent.

Q38. How did you utilize the projected earnings retention rates in estimating expected growth for the proxy companies?

A. As shown on page 5 of Schedule 3 of Exhibit No.___(JSG -2), I calculated a weighted average of the analysts' projected growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the

proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future.[1] The average of the weighted average growth rates for the proxy companies is 6.7 percent and the median is 6.9 percent.

Q39. How did you utilize these Second-Stage Retention Growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. The dividend yield for each company shown on page 3 of Schedule 4 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Schedule 4 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 10.2 percent and 15.4 percent. The median for the group is **12.6 percent**.

[1] This two-thirds weighting for analysts' forecasts is the same weighting that the FERC used in Opinion No. 414-A for setting the allowed return on equity for natural gas pipeline companies. *Transcontinental Gas Pipeline Co.*, 80 FERC ¶ 61,084 (1998).

Basic DCF Analysis

Q40. What approach did you use in conducting a Basic DCF analysis?

A. This analysis is conducted in substantially the same manner as the Second-Stage Retention Growth Rate analysis. However, the growth rate component of the analysis is based solely on the analysts' forecasts for each company and the retention growth rate component is omitted from the analysis. This Basic DCF analysis recognizes that the consensus of analysts' forecasts reflects the most important component of investors' growth rate expectations and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company.

Q41. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 7 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.0475 to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of **13.1 percent**.

Primary DCF Analysis

Q42. Would you please describe your Primary DCF analysis?

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

Q43. In your opinion, what are the factors that will affect growth rates for the proxy companies in the future?

A. One important factor will be growth in the overall economy. Page 1 of Schedule 2 of Exhibit No.___(JSG-2) shows that the United States Gross Domestic Product has grown at an average annual rate of 7.8 percent during the past 30 years. During the past decade U.S. GDP growth has averaged 5.6 percent. It is reasonable to expect that long-term future growth in the economy generally will be comparable to past growth rates. For example, DRI-WEFA forecasts that the U.S. GDP will grow at a rate of approximately 6.3 percent over the long-term.

Another factor will be growth in demand for electricity and related energy products. The U.S. Department of Energy forecasts that electricity output will increase at an annual rate of 1.7 percent during the next 20 years. Increasing amounts of generation, transmission and distribution facilities should be needed to achieve this growth.

In my opinion, investors reasonably expect the 12 companies in this comparison group to grow at a rate that is somewhere in the range of 6.25 percent to 7.25 percent. Based on the median and average growth rates of approximately 7.0 percent currently projected by investment analysts, as well as the 6.3 percent growth rate in the economy, increasing demands for electricity, and my review of these companies, I consider this growth rate range to be a reasonable estimate of the future growth expectations that are implicit in current dividend yields. This growth rate range is also consistent with the retention growth rates projected for these companies.

Q44. What does your primary DCF analysis indicate with regard to investors' current market rate of return requirements?

A. Page 8 of Schedule 4 of Exhibit No. ___(JSG-2) shows the calculation of the cost of capital based on my primary DCF growth rate estimates. The dividend yield used in this analysis is the average dividend yield for the electric utility proxy companies that is developed on page 3 of Schedule 4. This market-based primary DCF analysis indicates that the cost of capital for the proxy companies is approximately in the range of **12.2 percent** to **13.3 percent**.

Risk Premium Analyses

Q45. Have you conducted additional analyses in determining the cost of capital to Montana-Dakota?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater

risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual returns on large company common stocks have exceeded the yields on Long-Term U.S. Government Bonds by an average of 780 basis points (7.8 percent). However, the returns on relatively small company stocks in the size range of Montana-Dakota's electric operations have been 1,210 basis points (12.1 percent) above the yields on long-term government bonds. As shown on page 1 of Schedule 4 of Exhibit No. ___ (JSG-2), Montana-Dakota is a fraction of the size of any of the proxy companies. In recent

months, the yield on long-term U.S. Government bonds has been approximately 5.5 percent. Adding a 7.8 percent premium to a yield of 5.5 percent indicates that investors in large company common stocks require a return of at least 13.3 percent. Adding the 12.1 percent premium for companies in Montana-Dakota's size range suggests a required return of 17.6 percent.

Another risk premium approach is to examine the long-term premium of large company common stock returns as compared with returns on corporate bonds. This premium has averaged 740 basis points (7.4 percent) annually over a long period of time in the past. When this premium is added to the 7.4 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 14.8 percent. However, over the long-term companies in Montana-Dakota's size range have had a premium of 1,170 basis points (11.7 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 19.1 percent.

Alternative Equity Investment Analysis

Q46. Have you analyzed the returns available on common equity investments in other industries?

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process whereby projects and companies compete for scarce equity capital ensures that capital resources are deployed efficiently. As a result,

regulated electric utility operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

Q47. What level of returns are potentially available to unregulated companies?

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For example, page 3 of Schedule 2 of Exhibit No. ___(JSG-2) shows the average return on equity book value earned by companies in the S&P 500 each year from 1977 to 1999. It can be seen, in fact, that average returns for the S&P 500 companies have been 20.69 percent for the past five years. For purposes of comparison with allowed returns for regulated electric utility operations, a better indicator of earnings on alternative equity investments is provided by data on 746 industrial, retail and transportation companies published by *The Value Line Investment Survey*. Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years has been:

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

Q48. Is it appropriate to set the allowed rate of return for an electric utility company equal to the average return available to industrial companies?

A. The average return for industrials serves as a useful indicator of the cost of capital because electric utility companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. In exceptionally good times a regulated company might earn slightly more than this amount, but it might earn substantially less than the allowed return and, in fact, often does earn less than that amount. Thus, investors would expect that on average they will actually earn something less than the allowed amount. Electric utility companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for electric utility companies can be compared to returns on book value for large companies. Normal returns have averaged 29.4 percent during the past five years. Similarly, the average level of return experienced by the S&P 500 companies has been approximately 20.69

percent. As this comparison indicates, an allowed return of 12.75 percent for Montana-Dakota would be quite low in comparison with the returns earned by other large companies. Consequently, a return of this magnitude could potentially be too low for Montana-Dakota's electric operations to successfully compete for capital.

Relative Risk Analysis

Q49. Have you compared the risks faced by Montana-Dakota's North Dakota electric operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

Q50. Would you please describe the business risks inherent in the electric industry?

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived electric utility assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

One of the current sources of risk and uncertainty include the possibility of open-access transmission and customer choice programs that could introduce

widespread competition for electric generating customers. Because a large portion of the costs of electric generation are long-lived, fixed costs, there is a possibility that competitive electric generation markets could result in excess capacity that could take many years to subside. In any competitive market characterized by excess capacity there will be a tendency for prices to reflect short-run marginal costs. In other words, competitive prices could be so low that companies would be unable to recover all, or a portion of the sunk, fixed costs of their generating plants.

The business model of Montana-Dakota and other major utilities is based on the fact that traditionally electricity has been provided most efficiently by large, centralized generating plants connected to the market with extensive networks of transmission and distribution lines. However, in the future, demand for Montana-Dakota's electric services could be affected by the adoption of distributed generation technologies that allow customers to generate their own power instead of relying on utility generation, transmission or distribution. The overall efficiency of these technologies has improved significantly in recent years and some electricity consumers have begun installing and using distributed generation equipment. Shifts in the overall cost of distributed generation relative to the fuel and network costs of centralized utility generation could imperil the ability of some utilities to recover the investments they have made under the traditional "public utility model" of electricity supply.

In addition, the constantly-changing mandates of environmental laws disproportionately impact electric utilities, especially coal-burning utilities.

Litigation expenses and exposure to tort claims also is an increasingly important consideration for electric utility investors.

Q51. What are some of the business risks faced by Montana-Dakota's North Dakota electric operations?

A. These operations face many of the same risks that are associated with other electric utilities. However, Montana-Dakota faces three risks that distinguish it from many other utilities.

First, nearly all of its generation is from a single fuel source: coal. Utilities that are heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render all of their generating capacity uneconomic. Montana-Dakota's customers have benefited greatly from the company's use of low-cost coal, but there is an element of risk associated with this undiversified generating mix. For example, during the past decade there have been repeated discussions of the possibility that carbon dioxide emissions might be severely limited. If restrictions on carbon dioxide were to be enacted, coal-fired generation would be disproportionately impacted. Similarly, if prices for natural gas were to decline significantly, Montana-Dakota could find that its generating mix is uneconomic. In fact, most new generation constructed in recent years has been fueled with natural gas as a result of low gas prices and new, efficient generating technologies.

Second, as shown on Exhibit No. ___ (JSG-2), Schedule 4, page 1, Montana-Dakota's electric utility operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the

typical proxy company. For example, Montana-Dakota's electric utility assets are equal to only 4.8 percent of the assets of the median proxy company. Similarly, Montana-Dakota's electric operating revenues and operating income are only 4.5 percent and 6.6 percent of the level for the median proxy company. Thus, depending upon the measure of size, the typical proxy company is somewhere between 15 and 22 times the size of Montana-Dakota's electric utility operations.

This smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. On a practical level, Montana-Dakota's relatively small electric utility operations are heavily dependent upon a relatively undiversified local economy. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's electric services and adversely impact investments in facilities used to provide those services. Considering only its smaller size, Montana-Dakota might require a return that is more than 100 basis points higher than the return required for the typical proxy company.

Third, Montana-Dakota faces direct competition for new and existing load and is at a disadvantage in this competition. For example, much of the load growth in North Dakota is occurring in the larger cities. However, the larger cities served by Montana-Dakota in North Dakota are essentially ringed by rural electric cooperatives ("REC's"). Under the North Dakota Territorial Integrity Act, REC's are given control over service in the areas that they serve, even when a city annexes territory as the city grows. Consequently, as the cities served by

Montana-Dakota grow geographically, Montana-Dakota generally is unable to grow along with its larger cities. Since the smaller towns served by Montana-Dakota are generally losing population, there are few opportunities to offset this loss of population in smaller towns with growth in the larger cities. This disadvantage in attracting new load in North Dakota places Montana-Dakota at risk that its facilities will become underutilized and that it will be unable to recover its costs.

The existence of adjacent and surrounding electric cooperatives also means that Montana-Dakota faces competitive threats to its existing load. For example, in August 2001, Watford City, North Dakota held a referendum on whether to condemn Montana-Dakota's electric distribution facilities and contract with McKinsey Electric Cooperative for electric service. If this referendum had passed, generation and transmission facilities of Montana-Dakota might have been stranded.

With its undiversified generating sources, small size, limited growth opportunities and competitive threats and disadvantages, Montana-Dakota's North Dakota electric operations face greater overall business risk than the typical company in the electric utility proxy group.

Q52. What are the regulatory risks faced by Montana-Dakota's North Dakota utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for an electric utility company's services is sufficiently strong that the

company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on electric utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries. In fact, after the experiences of the 1980s, investors are concerned with the risks associated with after-the-fact prudence reviews and possible regulatory cost disallowances. In addition, investors are aware that ill-conceived regulatory restrictions associated with electric utility restructuring in California played a decisive role in causing Pacific Gas & Electric Company into bankruptcy and massive losses at Southern California Edison Company.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of electric utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the electric utility industry.

Value Line rates the regulatory climate in North Dakota as being "average." However, in 1997 the North Dakota legislature established an Electric Industry Competition Committee to study over a six-year period the impact of

competition on the electric utility industry in North Dakota. With the possibility of restructuring in the next several years, there must be some uncertainty in the minds of investors regarding the regulatory rules that will be applied to Montana-Dakota in the event that restructuring occurs. This uncertainty increases the perceived risk associated with Montana-Dakota's existing and future investments in its electric utility operations.

Q53. Would you please describe Montana-Dakota's relative financial risks?

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 4 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and MDU Resources. The median bond ratings for companies in the proxy group are A- for Standard & Poor's and A2 for Moody's. In comparison, MDU Resources bonds carry an A+ rating with Standard & Poor's and an A2 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is equal to or slightly

lower than that of the typical company in the comparison group. Examination of the capital structure data shown on page 9 of Exhibit No. ___ (JSG-2), Schedule 4 shows that Montana-Dakota's filed common equity ratio, 48.7 percent, is near the high end of the range for the proxy companies. This higher common equity ratio suggests lower financial risk that serves to offset the higher business risk faced by Montana-Dakota's North Dakota electric utility operations.

Q54. Would you please describe Montana-Dakota's market risks?

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

Q55. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's electric operations?

A. Montana-Dakota faces overall risks that are about average relative to those of the proxy companies. Montana-Dakota has above-average business risks due to its lack of diversified generation sources, its exceptionally small size relative to the proxy companies, and its competitive disadvantages. The fact that these higher business risks are offset by lower financial risks suggests that Montana-Dakota's electric operations are average relative to those of the proxy companies. These factors and the perception of an average regulatory climate in North Dakota lead me

to conclude that the overall risks of Montana-Dakota's electric utility operations are about average relative to the risks of the proxy companies.

III. SUMMARY AND CONCLUSIONS

Q56. Would you please summarize the results of your cost of capital study?

A. Yes. I conducted several DCF analyses on a group of electric utility companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota. The results of my various analyses can be summarized as follows:

	Investor Requirement Median/Average	Cost of Capital Median/Average
DCF Analyses		
Electric Utility Proxies:		
- Second-Stage Retention Growth	12.03%	12.60%
- Basic DCF	12.49%	13.09%
- Primary DCF	12.16%	12.73%
Benchmark Analyses		
Risk Premium Return Based On:		
- U.S. Treasury Bonds		
v. Large Companies	13.3	
v. Small Companies	17.6	
- Corporate Bonds		
v. Large Companies	14.8	
v. Small Companies	19.1	
Alternative Investments		
- S&P 500	20.7	
- Value Line Industrials	29.4	

My second-stage retention growth analysis indicates a median cost of common equity capital of 12.6 percent. Because projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. Combining these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a range of 10.1 percent to 16.1 percent and a median required rate of return of 13.1 percent.

My primary approach has been to analyze a variety of sources of information, including investment analysts' forecasts, in order to estimate a weighted average annual growth rate that investors reasonably can expect the electric utility comparison companies to achieve during a long period of time in the future. This primary DCF analysis indicates that the cost of capital for electric utility companies with risks comparable to those of Montana-Dakota is in a range between 12.2 percent and 13.3 percent. The mid-point of this range is approximately 12.75 percent.

My risk premium analyses indicate that my DCF estimates produce a premium over corporate bond yields that is below the average long-run risk

premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates generally are significantly below the 20.7 percent average return earned by the S&P 500 companies during the past five years. Moreover, the DCF returns are far below the 29.4 percent average normal returns earned by the Value Line Industrials in recent years.

Q57. What rate of return on common equity do you recommend for Montana-Dakota in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's North Dakota electric utility operations at this time would be **12.75 percent**. This recommended return reflects my assessment that Montana-Dakota's overall risks are about average relative to the proxy group. A return of 12.75 percent is very near the middle of the range for my Primary DCF analysis and is very close to the median for my Second-Stage Retention Growth analysis. It is also somewhat below the median return calculated using a basic DCF analysis.

Q58. Does this conclude your Prepared Direct Testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.

CAPITAL STRUCTURE - DEBT

12/31/2000

DEBT	BALANCE OUTSTANDING	ANNUAL COST	ADJUSTED EMBEDDED COST
LONG-TERM DEBT CAPITAL	$132,850,000	$11,874,562	8.938%
AMORTIZATION OF LOSS ON BOND REDEMPTION *		548,429	
LONG-TERM NOTE PAYABLE	243,971	19,226	7.880%
TERM LOAN	1,300,000	124,475	9.575%
COMMERCIAL PAPER	10,500,000	693,000	6.600%
COMMITMENT FEES ON LINES OF CREDIT		102,544	
TOTAL DEBT	**$144,893,971**	**$13,362,236**	**9.222%**

* Debt was fully retired May 1998 and no new debt was issued to replace it; cost amortized over original life of issue.

Sources: Exhibit No. ___(JSG-2), Schedule 1, page 2; Testimony of
Charles W. King, Schedule 1; Montana-Dakota.

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2000

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	$30,000,000	$30,000,000	$225,000	0.750%	$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.52%	09/30/97	10/01/04	6.520%	15,000,000	15,000,000	90,000	0.600%	827,077	5.514%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
Pollution Control Notes:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
				$136,450,000	$136,361,100	$892,750		$13,091,800	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2% *	5,427,042	96.911%	6.556%	2,000,000	131,120	6.556%
Total Long-Term Debt Capital	$122,376,550			$132,850,000	$11,874,562	**8.938%**

* Reflects 2001-2003 average as shown on Direct Testimony of Charles W. King, Schedule 1.

Sources: Montana-Dakota Response to Data Request No. 2 Dated June 18, 2001.

Montana-Dakota Utilities Co.

General Economic Statistics

1970-2000

Year	Percentage Price Changes: Consumer Price Index	Percentage Price Changes: GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP (Billions)
1970	5.7%	5.3%	0.2%	1,039.7
1971	4.4%	5.0%	3.3%	1,128.6
1972	3.2%	4.3%	5.4%	1,240.4
1973	6.2%	5.6%	5.8%	1,385.5
1974	11.0%	9.0%	-0.6%	1,501.0
1975	9.1%	9.3%	-0.4%	1,635.2
1976	5.8%	5.7%	5.6%	1,823.9
1977	6.5%	6.4%	4.6%	2,031.4
1978	7.6%	7.1%	5.5%	2,295.9
1979	11.3%	8.3%	3.2%	2,566.4
1980	13.5%	9.2%	-0.2%	2,795.6
1981	10.3%	9.3%	2.5%	3,131.3
1982	6.2%	6.2%	-2.0%	3,259.2
1983	3.2%	4.0%	4.3%	3,534.9
1984	4.3%	3.7%	7.3%	3,932.7
1985	3.6%	3.1%	3.8%	4,213.0
1986	1.9%	2.2%	3.4%	4,452.9
1987	3.6%	3.0%	3.4%	4,742.5
1988	4.1%	3.4%	4.2%	5,108.3
1989	4.8%	3.8%	3.5%	5,489.1
1990	5.4%	3.9%	1.8%	5,803.2
1991	4.2%	3.6%	-0.5%	5,986.2
1992	3.0%	2.4%	3.0%	6,318.9
1993	3.0%	2.4%	2.7%	6,642.3
1994	2.6%	2.1%	4.0%	7,054.3
1995	2.8%	2.2%	2.7%	7,400.5
1996	3.0%	1.9%	3.6%	7,813.2
1997	2.3%	2.0%	4.4%	8,318.4
1998	1.6%	1.2%	4.4%	8,790.2
1999	2.2%	1.5%	4.2%	9,299.2
2000	3.4%	2.1%	5.0%	9,965.7
Average Rate of Change: 1/				
1970-2000	5.2%	4.5%	3.2%	7.8%
1980-2000	4.2%	3.5%	3.1%	6.6%
1990-2000	3.0%	2.3%	3.2%	5.6%

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

Source: *Economic Report of the President*, February 2001.

Montana-Dakota Utilities Co.

Moody's Bond Yield Averages
December 1999 - November 2001

		Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated
1999	DEC	7.87	8.14	8.28
2000	JAN	8.06	8.35	8.40
	FEB	7.96	8.25	8.33
	MAR	7.99	8.28	8.40
	APR	7.98	8.29	8.40
	MAY	8.41	8.70	8.86
	JUN	8.05	8.36	8.47
	JUL	7.98	8.25	8.33
	AUG	7.88	8.13	8.25
	SEP	7.98	8.23	8.32
	OCT	7.95	8.14	8.29
	NOV	7.90	8.11	8.25
	DEC	7.65	7.84	8.01
2001	JAN	7.55	7.80	7.99
	FEB	7.50	7.74	7.94
	MAR	7.41	7.68	7.85
	APR	7.63	7.94	8.06
	MAY	7.69	7.99	8.11
	JUN	7.56	7.85	8.02
	JUL	7.51	7.78	8.05
	AUG	7.37	7.59	7.95
	SEP	7.54	7.75	8.12
	OCT	7.41	7.63	8.02
	NOV	7.32	7.57	7.96

Source: Mergent Bond Record.

Montana-Dakota Utilities Co.

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

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

Source: Standard & Poor's Analyst Handbook, 2000.

Mr. King's Electric Companies That Derive 75% of Revenue from Regulated Electric Service

King Co.	Company Name	Total Revenue	Regulated Electric Revenue	Regulated Gas Revenue	% of Revenue from Electric Operations
	Empire District Electric Co	260	259		99.6%
E	**Southern Company**	10,066	9,860		98.0%
E	**Kansas City Power & Light**	1,116	1,064		95.3%
C	**Sierra Pacific**	2,334	2,219	101	95.1%
E	**Pinnacle West**	3,690	3,480		94.3%
C	**Ameren**	3,856	3,526	324	91.4%
E	**FPL Group**	7,082	6,361		89.8%
C	**Progress Energy**	4,119	3,565	324	86.6%
	IDACORP (Idaho Power)	1,019	836		82.0%
C	**Puget Sound Energy**	3,442	2,772	612	80.5%
	American Electric Power	13,694	10,827		79.1%
C	**DPL Inc (Dayton Power & Lig**	1,437	1,090	184	75.9%
	Cleco Corp	821	620		75.5%
	Hawaiian Electric Co Inc	1,719	1,277		74.3%
	DTE Energy	5,597	4,129		73.8%
C	Consolidated Edison Inc.	9,431	6,938	1,262	73.6%
	Entergy Corp	10,016	7,220	166	72.1%
C	Alliant Energy	2,405	1,648	415	68.5%
C	Energy East	2,960	2,024	772	68.4%
\	Madison Gas & Electric	324	203	121	62.7%
	Allegheny Energy	4,012	2,507	*	62.5%
	TECO Enregy (Tampa Elec Co	2,295	1,354	314	59.0%
	Xcel Energy (No. States Power	11,592	6,492	1,466	56.0%
	PPL Electric Utilities Corp	5,683	3,167	*	55.7%
	Wisconsin Electric Power (Wis	3,355	1,798	736	53.6% #
	Constellation Energy Group	3,878	2,052	502	52.9%
	Rochester Gas & Electric	1,448	731	340	50.5%
	Dominion Resources (Va. Pow	9,260	4,492	1,374	48.5%
	Portland Gen Elec Co (Enron)	2,253	1,044		46.3%
	Oklahoma Gas & Electric	3,299	1,454		44.1%
	SCANA Corp (Pub Ser or NC,S	3,433	1,334	998	38.9%
	WPS	1,951	625	265	32.0%
	Cinergy Corp.	8,421	2,692	429	32.0%
	Sempra Energy	7,143	2,184	3,305	30.6%
	NI Source	6,031	1,557	1,807	25.8%
	TXU Corp	22,009	4,752	962	21.6%
	Vectren Corp	1,649	336	819	20.4%
	Reliant Energy	29,339	5,494	*	18.7%
	Black Hills Corp	1,624	173		10.7%
	Duke Enrgy	49,318	4,946		10.0%
	UGI Corp (UGI Utilities)	1,762	78	359	4.4%
	Utilicorp	28,975	1,208	826	4.2%
	NorthWestern Corp	7,132	87	95	1.2%
	MDU Resources Group	1,874	162	233	8.6%

* Companies that did not report electric and gas revenues separately.
Proportion of "electric" revenues is actually electric and gas revenues.

From SEC Form 10-K.

Montana-Dakota Utilities Co.

Statistical Comparison of Difference Between Mr. King's Two DCF Sample Results

Electric Utilities		Electric and Gas Utilities	
Company	DCF Return	Company	DCF Return
FPL Group	11.2	Alliant Energy	8.9
Kansas City P&L	12.9	Ameren	11.1
Pinnacle West	12.4	Consolidated Edison	9.6
Southern Company	11.7	DPL	13.4
		Energy East	11.1
		Progress Energy	12.2
		Puget Sound Energy	12.9
		Sierra Pacific	10.4

t-Test: Two-Sample Assuming Unequal Variances

	Electric	*Electric and Gas*
Mean	12.05	11.2
Variance	0.5633	2.4629
Observations	4	8
Hypothesized Mean Difference	0	
df	10	
t Stat	1.2690	
P(T<=t) one-tail	**11.66%**	
t Critical one-tail	1.8125	
P(T<=t) two-tail	23.32%	
t Critical two-tail	2.2281	

t-Test: Two-Sample Assuming Equal Variances

	Electric	*Electric and Gas*
Mean	12.05	11.2
Variance	0.5633	2.4629
Observations	4	8
Pooled Variance	1.893	
Hypothesized Mean Difference	0	
df	10	
t Stat	1.0089	
P(T<=t) one-tail	**16.84%**	
t Critical one-tail	1.8125	
P(T<=t) two-tail	33.68%	
t Critical two-tail	2.2281	

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
December 31, 2000 Operating Data

	Assets ($000,000)	Operating Revenues ($000,000)	Operating Income ($000,000)
Ameren	$9,714	$3,855	$942
American Electric Power	$54,548	$13,694	$2,229
Cleco Corp	$1,846	$820	$147
DPL Inc	$4,436	$1,437	$445
FPL Group	$15,300	$7,082	$1,307
IDACORP (Idaho Power)	$4,639	$1,019	$353
Great Plains Energy	$3,294	$1,116	$292
Pinnacle West	$7,149	$3,690	$676
Progress Energy	$20,091	$4,119	$1,087
Puget Sound Energy	$5,557	$3,442	$493
Sierra Pacific	$5,639	$2,334	$97
Southern Company	$31,362	$10,066	$2,404
High	$54,548	$13,694	$2,404
Median	**$6,394**	**$3,566**	**$585**
Low	$1,846	$820	$97
Montana-Dakota Electric Utility	**$305**	**$162**	**$39**
MDU Resources Group, Inc.	$2,313	$1,873	$217
Montana-Dakota Electric Util. % of:			
- Proxy Company Median	**4.8%**	**4.5%**	**6.6%**
- MDU Resources Group, Inc.	13.2%	8.6%	17.9%

Sources: Zacks.com and *Market Guide* on America Online; MDU Annual Report and 10-K.

Montana-Dakota Utilities Co.

Bond Ratings of
Selected Electric Utility Proxy Companies

	Standard & Poor's	Moody's
Ameren	A+	Aa2
American Electric Power	A-	A3
Cleco Corp	BBB+	A2
DPL Inc	BBB+	A2
FPL Group	A	Aa3
IDACORP (Idaho Power)	AA-	A2
Great Plains Energy	A	A1
Pinnacle West	A-	A3
Progress Energy	BBB+	A1
Puget Energy	BBB	Baa1
Sierra Pacific	A-	A3
Southern Company	A+	A1
Median	A-	A2
MDU Resources Group	A+	A2

Source: C.A. Turner, *Utility Reports*, December 2001.

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Dividend Yields
June 2001 - November 2001

		Stock Price June '01 - November '01				
		High	Low	Average	Dividend	Yield
Ameren	AEE	$ 44.50	$ 36.53	$ 40.52	$ 2.54	6.27%
American Electric Power	AEP	$ 50.40	$ 39.70	$ 45.05	$ 2.40	5.33%
Cleco Corp	CNL	$ 23.72	$ 19.40	$ 21.56	$ 0.88	4.08%
DPL Inc	DPL	$ 29.65	$ 22.05	$ 25.85	$ 0.94	3.64%
FPL Group	FPL	$ 65.61	$ 51.20	$ 58.41	$ 2.24	3.84%
IDACORP (Idaho Power)	IDA	$ 39.94	$ 33.55	$ 36.75	$ 1.86	5.06%
Great Plains Energy	GXP	$ 27.35	$ 23.19	$ 25.27	$ 1.66	6.57%
Pinnacle West	PNW	$ 50.00	$ 37.65	$ 43.83	$ 1.60	3.65%
Progress Energy	PGN	$ 45.79	$ 39.25	$ 42.52	$ 2.12	4.99%
Puget Sound Energy	PSD	$ 26.95	$ 18.51	$ 22.73	$ 1.84	8.10%
Sierra Pacific	SRP	$ 17.18	$ 13.70	$ 15.44	$ 0.80	5.18%
Southern Company	SO	$ 26.00	$ 22.05	$ 24.03	$ 1.34	5.58%
Average						5.19%
Median						5.12%

Sources: America Online and Standard and Poor's *Stock Guide*, December 2001.

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

	Value Line Forecast 2004-2006				
	EPS	DPS	ROE	Retention Rate	Retention Growth
Ameren	$ 3.75	$ 2.62	13.50%	30.13%	4.1%
American Electric Power	$ 4.75	$ 2.40	14.00%	49.47%	6.9%
Cleco Corp	$ 2.00	$ 0.96	15.50%	52.00%	8.1%
DPL Inc	$ 2.50	$ 1.00	23.00%	60.00%	13.8%
FPL Group	$ 5.25	$ 2.55	15.00%	51.43%	7.7%
IDACORP (Idaho Power)	$ 3.20	$ 1.86	11.50%	41.88%	4.8%
Great Plains Energy	$ 2.25	$ 1.66	13.50%	26.22%	3.5%
Pinnacle West	$ 4.30	$ 1.93	11.00%	55.12%	6.1%
Progress Energy	$ 4.80	$ 2.38	13.00%	50.42%	6.6%
Puget Sound Energy	$ 2.25	$ 1.84	13.00%	18.22%	2.4%
Sierra Pacific	$ 2.00	$ 1.10	10.00%	45.00%	4.5%
Southern Company	$ 2.10	$ 1.52	15.00%	27.62%	4.1%
Average					6.0%
MDU Resources	$ 2.50	$ 1.06	10.50%	57.60%	6.0%

Source: *Value Line*, October 5, November 16 and December 7, 2001.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth Rate
Estimates for Selected Electric Utility Proxy Companies

	2/3 Zacks 5-Yr Earnings Growth Est.	1/3 Retention Growth	Weighted Average
Ameren	4.40%	4.1%	4.29%
American Electric Power	6.91%	6.9%	6.92%
Cleco Corp	10.00%	8.1%	9.35%
DPL Inc	9.30%	13.8%	10.80%
FPL Group	7.12%	7.7%	7.32%
IDACORP (Idaho Power)	10.00%	4.8%	8.27%
Great Plains Energy	6.00%	3.5%	5.18%
Pinnacle West	8.67%	6.1%	7.80%
Progress Energy	7.06%	6.6%	6.89%
Puget Sound Energy	5.25%	2.4%	4.29%
Sierra Pacific	4.33%	4.5%	4.39%
Southern Company	5.31%	4.1%	4.92%
Average	7.0%	6.0%	**6.7%**
Median			**6.9%**

Sources: Zacks.com and page 6.

Montana-Dakota Utilities Co.

Second-Stage Retention Growth DCF Calculation for Selected Electric Utility Proxy Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
Ameren	6.27%	6.44%	4.29%	10.73%	1.0475	11.24%
American Electric Power	5.33%	5.56%	6.92%	12.47%	1.0475	13.07%
Cleco Corp	4.08%	4.32%	9.35%	13.67%	1.0475	14.32%
DPL Inc	3.64%	3.88%	10.80%	14.68%	1.0475	15.38%
FPL Group	3.84%	4.01%	7.32%	11.33%	1.0475	11.87%
IDACORP (Idaho Power)	5.06%	5.32%	8.27%	13.60%	1.0475	14.24%
Great Plains Energy	6.57%	6.78%	5.18%	11.96%	1.0475	12.53%
Pinnacle West	3.65%	3.83%	7.80%	11.63%	1.0475	12.18%
Progress Energy	4.99%	5.20%	6.89%	12.09%	1.0475	12.67%
Puget Sound Energy	8.10%	8.31%	4.29%	12.60%	1.0475	13.20%
Sierra Pacific	5.18%	5.32%	4.39%	9.71%	1.0475	10.17%
Southern Company	5.58%	5.75%	4.92%	10.67%	1.0475	11.18%
Average	5.19%		6.70%	12.10%		12.67%
High				14.68%		15.38%
Median				12.03%		**12.60%**
Low				9.71%		10.17%

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Selected Electric Utility Proxy Companies

	Dividend Yield	Dividend Yield Times (1 + .625g)	Expected Growth Rate (g)	Investor Required Return	Flotation Cost Adjustment	Cost of Capital
Ameren	6.27%	6.44%	4.40%	10.84%	1.0475	11.36%
American Electric Power	5.33%	5.56%	6.91%	12.47%	1.0475	13.06%
Cleco Corp	4.08%	4.34%	10.00%	14.34%	1.0475	15.02%
DPL Inc	3.64%	3.85%	9.30%	13.15%	1.0475	13.77%
FPL Group	3.84%	4.01%	7.12%	11.13%	1.0475	11.65%
IDACORP (Idaho Power)	5.06%	5.38%	10.00%	15.38%	1.0475	16.11%
Great Plains Energy	6.57%	6.82%	6.00%	12.82%	1.0475	13.42%
Pinnacle West	3.65%	3.85%	8.67%	12.52%	1.0475	13.11%
Progress Energy	4.99%	5.21%	7.06%	12.27%	1.0475	12.85%
Puget Sound Energy	8.10%	8.36%	5.25%	13.61%	1.0475	14.26%
Sierra Pacific	5.18%	5.32%	4.33%	9.65%	1.0475	10.11%
Southern Company	5.58%	5.76%	5.31%	11.07%	1.0475	11.60%
Average	5.19%		7.03%	12.44%		13.03%
High				15.38%		16.11%
Median				12.49%		**13.09%**
Low				9.65%		10.11%

Montana-Dakota Utilities Co.

Primary DCF Analysis
Computation of the Cost of Capital
for Selected Electric Utility Proxy Companies

Growth Rate Estimate (g)	6.25%	7.25%
Current Dividend Yield (D/P)	5.19%	5.19%
Quarterly Model Dividend Yield Factor (1 + .625 g)	X 1.039	X 1.045
DCF Dividend Yield Component (Y)	5.39%	5.42%
Investor Required Return (Y + g)	11.64%	12.67%
Flotation Cost Adjustment	X 1.0475	X 1.0475
Cost of Capital	12.19%	13.27%
Mid-Point	**12.73%**	

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Capital Structures as of September 30, 2001

	Long-Term Debt (Millions)	%	Preferred Stock (Millions)	%	Common Equity (Millions)	%	Total Capital
Ameren	$ 2,858.6	44.34%	$ 235.2	3.65%	$ 3,353.2	52.01%	$ 6,447.0
American Electric Power	$ 14,704.0	67.35%	$ -	0.00%	$ 7,129.0	32.65%	$ 21,833.0
Cleco Corp	$ 658.2	56.70%	$ 15.8	1.36%	$ 486.9	41.94%	$ 1,160.9
DPL Inc	$ 2,150.9	79.09%	$ 23.0	0.85%	$ 545.8	20.07%	$ 2,719.7
FPL Group	$ 6,435.0	50.91%	$ 226.0	1.79%	$ 5,979.0	47.30%	$ 12,640.0
IDACORP (Idaho Power)	$ 879.3	47.56%	$ 104.5	5.65%	$ 865.0	46.79%	$ 1,848.8
Great Plains Energy	$ 1,373.2	58.52%	$ 39.0	1.66%	$ 934.3	39.82%	$ 2,346.5
Pinnacle West	$ 2,749.9	52.47%	$ -	0.00%	$ 2,491.3	47.53%	$ 5,241.3
Progress Energy	$ 9,346.5	60.47%	$ -	0.00%	$ 6,110.3	39.53%	$ 15,456.8
Puget Sound Energy	$ 2,248.5	65.42%	$ 110.7	3.22%	$ 1,077.7	31.36%	$ 3,436.8
Sierra Pacific	$ 2,970.1	65.91%	$ 50.0	1.11%	$ 1,486.5	32.99%	$ 4,506.6
Southern Company	$ 8,469.5	61.25%	$ -	0.00%	$ 5,357.7	38.75%	$ 13,827.3
Average		**59.16%**		**1.61%**		**39.23%**	
Median		**59.49%**		**1.24%**		**39.67%**	

Sources: Zacks.com and *Market Guide* on America Online.

Montana-Dakota Utilities Co.

Flotation Costs Associated With Electric Company Common Stock Issues 1996-2000

COMPANY	YEAR	MONTH	DAY	AMOUNT OFFERED ($000)	PRICE TO PUBLIC	Net Proceeds	Issue Cost as a Percent of Net Proceeds
Dynegy, Inc.	2000	APR	18	467,500	55.000	53.075	3.63%
Southern Company	2000	DEC	7	712,500	28.500	27.560	3.41%
NRG Energy Inc.	2000	MAY	30	422,550	15.000	14.100	6.38%
TNPC	2000	OCT	4	504,000	21.000	19.790	6.11%
Dynegy, Inc.	2000	OCT	12	528,750	52.875	52.655	0.42%
CMS Energy	2000	OCT	16	200,750	18.250	17.770	2.70%
GPU	1998	FEB	12	241,331	39.563	38.459	2.87%
Niagara Mohawk	1998	JUN	25	316,386	14.125	13.515	4.51%
AES	1998	SEP	4	150,000	44.625	43.183	3.34%
Northern States Pwr	1997	SEP	17	223,031	49.563	48.294	2.63%
Gothic Energy	1996	JAN	25	13,800	6.000	5.120	17.20%
Central & Southwest	1996	FEB	21	356,063	26.375	25.588	3.08%
Pacificorp	1996	MAR	5	177,438	20.875	20.216	3.26%
Calpine	1996	SEP	19	288,720	16.000	15.100	5.96%
TNP Enterprises	1996	SEP	25	42,656	24.375	23.471	3.85%
Average 1996-2000							**4.62%**

Source: Public Utility Finance Tracker.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
Terry L. Blinsky

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

A. Yes. My name is Terry L. Blinsky and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Electric Bulk Power Marketing Coordinator for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Electric Bulk Power Marketing Coordinator?

A. As the Electric Bulk Power Marketing Coordinator, I am responsible for the forecasting of daily power requirements of Montana-Dakota's electric customers and meeting those needs by using the economical dispatch of our available generation. I also perform the forward purchase or sale of power on daily, weekly, or monthly transactions.

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

A. I graduated from the lineman program at Mitchell Technical Institute in 1978. I began my employment with Montana-Dakota in May 1978, as an apprentice lineman. In 1983 I transferred to General Office and held the positions of Engineering Assistant and Dispatch System Operator, where I

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Direct Testimony of Terry L Blinsky
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 6
01/11/2001 CC: Comm Legal Illona, Pat, Jerry Mike

became a North American Electric Reliability Council (NERC) certified dispatcher. I became the Electric Bulk Power Marketing Coordinator in 1998.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss current conditions in the wholesale power market and to calculate the representative level of wholesale electric sales given current conditions.

Q. Would you please describe how you sell wholesale electricity?

A. Yes. Let me first explain that Montana-Dakota uses economic dispatch principles to meet the requirements of its retail customers. Economic dispatch includes the purchasing of energy when it is a lower cost alternative than running one of our generating units. On a daily basis, Montana-Dakota calculates its retail customer load requirements by hour for the next five days, using a forecast tool that takes into account historical load and weather. We then compare the retail load requirements with available generation for the same time period. Any generation not being used to meet retail load is available for wholesale sales.

Montana-Dakota's wholesale marketing function sells electricity in the open market through the Mid-Continent Area Power Pool (MAPP). When going into the market we sell at the highest price that someone is willing to pay as long as this price is higher than Montana-Dakota's generation fuel cost.

Q. Who are the customers that Montana-Dakota sells its wholesale power to through MAPP?

A. Montana-Dakota sells to other utilities and all other entities that act as marketing agents of other companies.

Q. Has Montana-Dakota been able to achieve higher levels of wholesale sales in the last few years?

A. Yes it has.

Q. Will Montana-Dakota be able to continue making wholesale sales at the levels experienced in the last few years?

A. No. The opportunities for us to make this level of wholesale sales peaked in 2001 and will be significantly reduced in 2002 and beyond.

Q. What factors allowed Montana-Dakota to achieve the higher levels of wholesale electric sales in the last few years?

A. In my view it was a market anomaly that allowed Montana-Dakota to make the wholesale sales levels that it did in the last few years. The first factor causing higher prices in the wholesale electric market in the last few years was that demand had outpaced supply. Increasing demand for electricity had been driven by a generally robust economy. Construction of new generation facilities has been slow for a number of years and simply did not keep pace with the increasing demand for electricity. Those companies that had available generation were able to sell to those companies buying it at prevailing market prices. I should note that those market prices were higher than any we have seen in the past.

The second factor is that natural gas prices were very high, particularly in the winter of 2000-2001 and continuing through early summer 2001. This

factor made gas-fired generation very expensive and buyers were looking for less expensive alternatives such as coal-fired generation. As Montana-Dakota's generation supply mix is primarily coal-fired and we had the energy to sell, we were able to enter into a number of transactions at very favorable prices.

A third factor was that many wholesale purchasers of electricity were buying in the short term market rather than building generation or buying power under long term contracts at stable prices. Price volatility resulted which again brought opportunities to tie into short term sales at higher prices than previously experienced.

Q. What has changed that leads you to believe that Montana-Dakota will no longer be able to achieve the level of wholesale sales and resulting margins that it has experienced in the recent past?

A. The wholesale market environment has drastically changed and our opportunities to make higher wholesale sales levels no longer exist in the current market. First, demand for electricity has slowed in the face of the downturn in the general economy. Also, supply has increased with a number of new generators on line. For example, generation added or planned in the Mid-Continent Area Power Pool (MAPP) was 658 MW in 2000, 1,774 MW in 2001, 1,759 MW in 2002 and 4,440 MW for the years 2003 through 2005. With supply and demand more nearly in balance, the prices for sales into the wholesale market have fallen to historic levels, and are expected to stay there.

The second change is that natural gas prices are currently about $2.10 per dk while a year ago natural gas prices were about $9.00 per dk. No one in the industry, to my knowledge, expects gas prices to return to those higher levels. In fact, the current New York Mercantile Exchange (NYMEX) gas futures prices remain under $3.80 per dk in every month through December 2007. This significant drop in natural gas prices from those in effect a year ago makes gas-fired generation much more economical again as a generation resource for those that have it available to them and has severely cut into our ability to make sales, especially at the prices of the past.

Q. How do today's wholesale electric prices compare with the prices of a year ago?

A. I have provided a comparison of the futures prices from last year and the current futures prices. The comparison uses the NYMEX futures prices for electricity at the Cinergy trading hub as of December 2000 and those of today. The comparison is shown on Exhibit No.____ (TLB-1). As you can see, in December 2000 the futures price for July and August 2001 deliveries was at $142.50 per Mwh, which represents the highest price at that time. The current NYMEX futures prices, again for the Cinergy hub, reflect a high of only $44.00 per Mwh for July and August 2002 contracts which represents the high point for 2002. Last year the low was $43.00 per Mwh which occurred in the last quarter of 2001. This year the low is $22.90 per Mwh for contracts for March and April 2002. I should note that the NYMEX futures prices represent actual contracts between willing sellers and willing buyers.

Q. Is it anticipated that the prices for power will rebound to the levels experienced in the recent past?

A. No. Given the current supply and demand market conditions, I believe that the high prices seen in the recent past are not likely to recur. This is supported by the NYMEX futures prices. On Exhibit No.___ (TLB-2) I have listed the NYMEX electric futures for the period February 2002 through July 2003. As you can see, there is no return to the prices experienced in 2001.

Q. Have you performed a calculation of the wholesale sales and resulting margins that Montana-Dakota can expect to make in the future?

A. Yes, I have.

Q. Would you please describe that calculation?

A. Yes. The calculation is shown on Exhibit No.____(TLB-3). As the final numbers for the month of December 2001 are not available at this time, I have used the actual results for the twelve months ended November 2001. Although it is highly questionable that we will be able to sell the same quantities of wholesale power as we did in 2001, I have assumed that we will sell the same quantities that we did in the twelve months ended November 2001. Those quantities are shown for the on-peak and off-peak periods on the exhibit. I have also shown the actual total sales in dollars and the resulting margin. The margin is the total revenue received less fuel costs. As noted on the exhibit, the total margin for the twelve months ended November 2001 was $15,554,890.

I then priced the historic on-peak Mwh sales at the current NYMEX futures prices for the period February 2001 through November 2001 on a monthly basis. The NYMEX prices are those posted as of January 2, 2002. I used the February price as a proxy for January as a futures price is not available after the first of the month. The off-peak price is estimated based on the current prices obtained for off-peak sales.

Q. Would you please explain the difference between on-peak and off-peak sales and why you priced the on-peak sales at the NYMEX futures and the off-peak sales at a significantly lower level?

A. Yes. First, let me define on-peak and off-peak. On-peak is the hours of 6:00 AM through 10:00 PM central time Monday through Saturday and off-peak is all other times. On-peak is a much more sought after commodity since most companies have higher load levels during the day than at night and buyers typically purchase energy to cover their loads for on-peak periods, making on-peak energy a more tradable commodity. The NYMEX futures prices are for firm energy which by definition is the on-peak period.

Off-peak is a time when load levels are low, and most companies have excess generation available. The off-peak market commands significantly lower prices and many sellers are willing to sell essentially at incremental cost to keep power plants running at their most efficient levels or, in some cases, maintain minimum operating levels. Off-peak power is not a highly tradable commodity like on-peak power and there is no futures index for off-peak power.

Q. What is the result of your calculation?

A. As shown on the exhibit, Montana-Dakota can expect, given current market conditions, to receive a margin of about $7,247,000 assuming that it is able to sell the same level of Mwh that it did in the twelve months ended November 2001. As I mentioned earlier, it is highly questionable that we will be able to sell the same quantities of wholesale power given current market conditions. I would also note that our ability to sell the same quantities will be affected by the generation work scheduled for 2002 that is discussed in the testimony of Mr. Gress.

Q. Does this complete your testimony?

A. Yes, it does.

NYMEX FUTURES
CINERGY HUB

As of December 2000 ($/Mwh)			As of January 8, 2002 ($/Mwh)			
Jan	2001	$75.00	Jan	2002	$23.40	1/
Feb	2001	75.00	Feb	2002	23.40	
Mar	2001	51.50	Mar	2002	22.90	
Apr	2001	51.50	Apr	2002	22.90	
May	2001	54.50	May	2002	26.40	
Jun	2001	83.50	Jun	2002	34.00	
Jul	2001	142.50	Jul	2002	44.00	
Aug	2001	142.50	Aug	2002	44.00	
Sep	2001	44.00	Sep	2002	23.75	
Oct	2001	43.00	Oct	2002	23.50	
Nov	2001	43.00	Nov	2002	23.50	
Dec	2001	43.00	Dec	2002	23.50	

1/ Assumed to be the same as February 2002.

NYMEX FUTURES
CINERGY HUB
AS OF JANUARY 8, 2002
($/MWH)

Feb	2002	$23.40
Mar	2002	22.90
Apr	2002	22.90
May	2002	26.40
Jun	2002	34.00
Jul	2002	44.00
Aug	2002	44.00
Sep	2002	23.75
Oct	2002	23.50
Nov	2002	23.50
Dec	2002	23.50
Jan	2003	26.50
Feb	2003	26.50
Mar	2003	25.50
Apr	2003	25.50
May	2003	28.00
Jun	2003	35.00
Jul	2003	45.00

MONTANA-DAKOTA UTILITIES CO.
POOL SALES CALCULATION

	On-Peak Sales (Mwh)	Off-Peak Sales (Mwh)	Total Sales (Mwh)	Total Sales Revenue	Margin	Actual Fuel Cost per Mwh	Futures On-Peak Price 1/	2002 Est. Off-Peak Price	2002 Margin Estimate
Jan-01	42,675	41,265	83,940	$2,336,055	$1,316,007	$12.15	$24.00	$12.50	$519,964
Feb-01	40,903	40,002	80,905	2,081,529	1,245,423	10.33	24.00	12.50	645,591
Mar-01	52,292	43,693	95,985	2,600,162	1,564,642	10.79	24.00	12.00	743,803
Apr-01	39,727	40,154	79,881	2,193,183	1,335,859	10.73	24.00	12.00	577,972
May-01	27,343	23,548	50,891	1,345,245	459,452	17.41	27.25	12.50	153,654
Jun-01	28,866	18,586	47,452	2,088,900	1,396,597	14.59	36.25	12.50	586,415
Jul-01	32,476	26,985	59,461	3,582,253	2,640,279	15.84	47.00	13.00	935,203
Aug-01	37,571	29,082	66,653	4,066,038	2,969,765	16.45	47.00	13.00	1,047,629
Sep-01	37,593	36,413	74,006	1,437,175	644,063	10.72	25.35	12.50	615,033
Oct-01	44,942	35,572	80,514	1,575,604	591,734	12.22	24.50	12.00	544,072
Nov-01	46,911	33,155	80,066	1,530,192	639,113	11.13	24.50	12.00	656,101
Dec-00	33,640	36,892	70,532	1,796,811	751,956	14.81	24.50	12.00	222,029
Total	464,939	405,347	870,286	$26,633,148	$15,554,890				**$7,247,467**

1/ Based on 2002 Futures On-Peak prices at of January 2, 2002.

Case No. PU-399-01-186
Exhibit No.____(TLB-3)
Page 1 of 1

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
Gerald L. Gress

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

A. Yes. My name is Gerald L. Gress and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Power Production Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Power Production Manager?

A. As Power Production Manager, I am responsible for the operation, maintenance and environmental compliance of Heskett Station, Lewis & Clark Station, Glendive Gas Turbine, Miles City Gas Turbine and the Williston Gas Turbines. I also represent Montana-Dakota's interests in the Coyote and Big Stone Stations.

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

A. I graduated from Purdue University, West Lafayette, Indiana, in 1971 with a Bachelor of Science degree in Electrical Engineering Technology. I also graduated from University of Evansville, Evansville, Indiana, in 1987 with a Masters in Business Administration. I am a member of the Institute of Electrical and Electronics Engineers (IEEE). I have held various positions in power production for thirty years and my present position since 1993.

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Direct Testimony of Gerald L Gress
by Montana-Dakota Utilities Co., a Division of MDU R
Exhibit # 6
01/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike

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

A. Yes, I have. I have presented testimony before the Commission in Indiana.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain Montana-Dakota's generation and maintenance schedule for its generation facilities. I also will identify and explain certain 2002 capital expenditure requirements related to Montana-Dakota's generation facilities that are above the normal capital requirements level.

Q. What is Montana-Dakota's general schedule for generation outages and overhauls at its generation stations?

A. Montana-Dakota is on a three-year rotation for boiler major outages and a six-year rotation for turbine/generator (T/G) major overhauls. However, there were some unscheduled events that reduced our major expenses and outages in 2000 and 2001.

Q. Would you please explain those events and the impact they had on Montana-Dakota's schedule for maintenance and outages?

A. Yes. First, Lewis & Clark Station had a controls upgrade in 1999 and an unscheduled T/G overhaul in the summer of 1999. These events advanced the maintenance and outage schedule so it was not necessary to have a T/G overhaul in 2000 or 2001, but a boiler outage will occur in 2002. The next T/G overhaul will be in 2005.

Second, Heskett Station had a generator failure on Unit 2 in 2000 and we took advantage of this event to do a turbine major overhaul even though the T/G overhaul was scheduled for 2001. We avoided outage time and expense to do the T/G overhaul in 2001 by doing it in 2000 while the generator was being repaired. The generator failure was covered by insurance.

Third, Heskett Station Unit 1 was put into reserve shut down in 1995 and operated at low loads before and after the shut down. This allowed us the opportunity to extend the normal run time between major turbine overhauls to the spring of 2002.

Coyote Station had a boiler and T/G major overhaul in 1997 and extensive repairs were made to get the boiler upgraded for a six year run with only a minor outage in 2000. This allowed us to keep costs down. The next T/G and boiler major overhauls are scheduled for 2003.

In summary, 2000 and 2001 were minimum maintenance and low cost years. We must now resume our planned maintenance schedule with major T/G and boiler overhauls in 2002, 2003 and 2004. Planned major maintenance will increase capital expenditures in 2002, 2003 and 2004 at most of the generating facilities.

Q. Would you please explain the major projects for 2002 that represent an increase over the normal capital budget?

A. Yes. Heskett Unit 1 will have a major turbine/generator overhaul in the spring of 2002. During the outage we will replace the condenser tubes,

upgrade the control system, modify the bottom ash system, replace sootblowers, replace grate chains and perform asbestos abatement at a cost of about $906,000. This overhaul is necessary to insure the unit's availability during peak load seasons. Heskett Unit 2 is scheduled for sootblowers to clean the inbed superheater in 2002 at a cost of about $254,000. This work is necessary to prevent agglomerations from forming in the inbed superheater tube bundle that would cause a forced outage.

Lewis and Clark is scheduled for major ductwork replacement for about $533,000 and scrubber maintenance for about $259,000 in 2002. This work is necessary because the metal in the ductwork has deteriorated to the point where it has a high probability of failure which would force the unit off line.

At Coyote, the low-pressure rotor is scheduled for replacement in 2002-2003 at a cost of about $1.3 million ($804,000 in 2002) and the boiler controls will be replaced at a cost of about $1.5 million ($675,000 in 2002). This work is necessary because several low-pressure rotors of the same design have failed in service at other power plants. In fact, the rotor at Coyote failed in December of 1999 and was replaced with a spare. A new design rotor will insure reliability during peak demand periods. The control system is obsolete and repair parts are not available any more. To insure unit availability during peak demand periods, the control system must be replaced.

At Big Stone a new technology type precipitator will be installed in 2002. The project will be done in conjunction with the Department of Energy (DOE), who is also contributing to the cost, as a demonstration of the new

technology. The cost to Montana-Dakota will be about $1,193,000. This improvement is necessary because we have to reduce load when the air emissions exceed the limits imposed on the unit by the Environmental Protection Agency (EPA). The electrostatic precipitator removes particulate emissions from the stack on a coal fired power plant. The unit at Big Stone has failed several times in the past, resulting in load reductions during peak times. In order to insure the availability of the unit, protect the environment and maintain capability during peak demand periods, the electrostatic precipitator has to be rebuilt and performance improved.

In total these projects represent $4,572,000 of system-wide capital requirements that are necessary in 2002. I also would note that this represents an increase in the capital requirements for generation from the levels experienced in the last few years.

Q. Are there any other significant capital expenditures related to generation planned for the next few years?

A. Yes. Montana-Dakota plans to add a new combustion turbine generator to its system to meet the continuing needs of our retail customers. The installed cost of the new turbine will be about $20 million.

Q. When does Montana-Dakota plan to have the new turbine in service?

A. The Integrated Resource Plan (IRP) filed with the Commission in mid-2001 shows a 2005 planned in-service date for the turbine. However, in the summer season of 2001, Montana-Dakota experienced an all time peak on its electric system. The peak was 453 MW and occurred on August 7, 2001.

This peak left us 16.9 MW short of our peak load obligation and we will be charged a penalty for exceeding our capability. Given this shortfall in our peak load obligation, Montana-Dakota is now considering the possibility of moving the planned in-service date for the turbine to May 1, 2004. We have not made a final decision at this time but are studying the issue.

Q. Would the total $20 million capital requirement be spent in one year?

A. No. Assuming an in-service date of May 1, 2005 we will be required to spend about $2 million in 2003, about $14 million in 2004 and the remaining $4 million in early 2005. If the in-service date is moved to May 1, 2004, the dollars will have to spent in 2002, 2003 and 2004 respectively.

Q. Does this complete your testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
Of
Donald R. Ball

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

A. Yes. My name is Donald R. Ball and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Director of Regulatory Affairs of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Director of Regulatory Affairs?

A. As Director of Regulatory Affairs, I am responsible for revenue requirements, rate administration, economic research, rate design and load research.

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

A. I graduated from Black Hills State College, Spearfish, South Dakota, in 1969 with a Bachelor of Science degree in Business Administration, with emphasis on accounting. I began my career with Montana-Dakota in September of 1969 at the Company's Rapid City, South Dakota office. I held various positions in the Company before achieving my present position in 1999.

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

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Direct Testimony of Donald R Ball
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 6
01/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike

A. Yes, I have. On a number of occasions, I have presented testimony before the Commissions in Montana, North Dakota, South Dakota and Wyoming. I have also testified before the Federal Energy Regulatory Commission (FERC) regarding Montana-Dakota's rates and purchased gas cost adjustments.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify and explain certain known and measurable changes to the cost of providing electric service for the 2000 test year chosen by the North Dakota Public Service Commission Staff (Staff). The adjustments that I will describe represent changes in the cost of providing electric service that are not reflected in the Staff case and must be considered in determining whether the existing rates are just and reasonable. The Staff case is not representative of the costs incurred by Montana-Dakota in providing electric service to its North Dakota retail customers. Ms. Mulkern, a later Company witness, will include the effects of these adjustments in her testimony.

Q. Would you please describe the adjustments you propose to operation and maintenance expense?

A. Yes. The adjustments that I propose for operation and maintenance expense are as follows:

- ✓ Demand Penalty - This adjustment is for penalties that will be assessed by MAPP as Montana-Dakota, despite its best efforts to have sufficient capacity to meet its reserve obligation for retail customers, was 6.3 MW

deficient in capacity in the summer of 2000 and deficient in capacity by 16.9 MW in 2001. MAPP has not yet assessed the penalties but, given their past practice, the penalty for 2000 will be assessed and paid this year and the 2001 penalty will be assessed and paid in 2003. The amount for 2000 is $375,000 on a system-wide basis. The penalty consists of two components, a capacity charge and a transmission charge. The amount for 2001 will be about $1,007,000 and consists of the same two components. As Montana-Dakota is required to make these payments, which are associated with providing electric service to retail customers, it is appropriate to recognize the expense in the cost of service determination. As the 2000 penalty relates to the calendar year 2000 used by the Staff, it is appropriate to include the $375,000 for the 2000 penalty.

✓ AVS Major Maintenance - This adjustment relates to the Antelope Valley generating station Unit II (AVS-II). The unit is owned and operated by Basin Electric Power Cooperative and Montana-Dakota purchases about 66 MW on a firm basis under a long term purchase contract. Although Montana-Dakota does not have an ownership interest in the unit, the contract terms and conditions require that Montana-Dakota pay its portion of all costs of the unit based on the 66 MW purchase level, including major maintenance. AVS-II is on a three year maintenance schedule and such major maintenance occurred in 2001. As such, there is no amount reflected in the Staff analysis that would recognize this expense. In 2001,

Montana-Dakota was billed $1.4 million in additional costs related to the major maintenance. As the major maintenance is scheduled for every three years, it is appropriate to amortize these costs over a three year period in the cost of service determination. This equates to an annual expense of $460,000 for Montana-Dakota on a system-wide basis.

✓ MISO RTO – This adjustment relates to changing costs as a result of Montana-Dakota joining the Midwest Independent System Operator Inc. (MISO) regional transmission organization (RTO). Pursuant to Federal Energy Regulatory Commission (FERC) Order No. 2000, Montana-Dakota investigated a number of options for compliance and joined MISO in September, 2001. The major cost change under MISO is that Montana-Dakota will no longer receive transmission revenues which were formerly received under MAPP Service Schedule F for power transmitted on or across its system. This revenue stream will not be replicated under the MISO pricing structure. The impact of this loss in revenues is $563,000 annually on a system-wide basis.

✓ Labor - On January 1, 2001, there was an average 4.32% increase in wages for Montana-Dakota employees. On January 1, 2002, there was an average 3.5% increase in wages granted to employees. As the Staff analysis reflects results for the calendar year 2000, the current wage levels are not reflected although the expenses are currently being experienced. The change amounts to $984,000 applicable to North Dakota electric operations.

✓ Pension & Benefits- Montana-Dakota is experiencing a substantial increase in pension and post retirement benefit costs. The increases are based on information received from the Company's actuary, Towers Perrin. The increases are caused by two primary factors. The first is that the asset returns are substantially lower than the abnormally high returns received in recent years and the second is that the discount rate used to measure the liability will decrease to reflect current long term interest rates. Both of these factors drive up the cost. The increases are expected to continue through 2006 but only the 2002 amount is reflected in the data provided in this testimony. The amount applicable to North Dakota electric operations for 2002 is $114,000.

I also have included $624,000 for North Dakota electric operations related to the Company's Supplemental Income Security Plan which provides a supplemental pension benefit to key employees. This supplemental pension benefit is necessary to attract and retain high quality staff in a number of key positions within the company.

✓ Insurance Expense- Insurance costs were increasing prior to September 11, 2001, but after the tragic events of that day, the effect was exacerbated. Based on discussions and negotiations with carriers, some categories of insurance are going up 50 to 70 percent. This is not unique to Montana-Dakota. Factoring in the increases to the costs for the calendar year 2000 included in the Staff analysis requires an adjustment of $116,000 applicable to North Dakota electric operations.

✓ Contributions, Energy Share of North Dakota - Energy Share of North Dakota fulfills a critical role by assisting customers, who do not qualify for other forms of assistance, in paying their energy bills. This has a positive impact on arrears and ultimately helps with uncollectible accounts for Montana-Dakota. It also provides a needed service for those who are experiencing difficulty in paying their bills. Energy Share of North Dakota also performs weatherization and repair services which helps to conserve energy and assure that customers have safe equipment. As such, I believe it is appropriate to include this expense. The amount is $9,000 for electric operations.

✓ Contributions, Lignite Energy Council - The Lignite Energy Council's (LEC) primary objective is to maintain a viable lignite coal industry and enhance development of the region's lignite coal resources for use in generating electricity, synthetic natural gas and viable byproducts. The LEC's critical role of maintaining the viability of the lignite coal industry and developing the region's lignite coal resources is essential in enabling Montana-Dakota to fulfill its commitment to provide reliable, low cost electric service to its customers by way of reliable, economic fuel for generation.

Also, enhanced development of the lignite coal industry provides economic stimulus to the region. According to the LEC, over 18,000 jobs, $1.3 billion in business volume and $60 million in tax revenue are generated by the lignite industry for the State of North Dakota each year. In addition, the LEC's Research, Development and Marketing Program

provides grants to assist research and development, preserve and enhance jobs and production and ensure economic growth, stability and opportunity. The research and development activities have allowed plants to operate more efficiently, more environmentally friendly and more economically, resulting in electric service benefits for all customers. Participation in the LEC, including financial participation in the form of contributions, is simply a legitimate, responsible and reasonable cost of doing business. Inclusion of this contribution in the cost of service will merely afford Montana-Dakota the opportunity to recover its legitimate costs of doing business. For these reasons, LEC contributions should be included in the cost of service in this proceeding. The amount applicable to North Dakota electric operations is $24,000.

Q. Would you please explain the adjustments you made to rate base?

A. The rate base adjustments I have made reflect added capital requirements for 2002, that is, requirements above the capital requirement level that we have had in recent years that should be adopted by the Commission in its determination in this proceeding. The adjustments are as follows:

- ✓ Transmission Line – This adjustment to rate base is a capital expenditure of $668,000 for refurbishing the Heskett-Bismarck 115 KV transmission line. The conductor must be replaced to enhance the reliability of the line.
- ✓ Underground Distribution Cable – This adjustment relates to the replacement of underground distribution cable of the pre-1984 vintage.

We have been experiencing an increasing number of faults on such cable and will have increased capital expenditures in 2002 of about $250,000 for replacement.

✓ Fleet Vehicle & Work Equipment - Another significant capital expenditure that will be incurred in 2002 is $463,000 of increased fleet vehicle and work equipment needs.

✓ Prepayments – This adjustment to rate base reflects the inclusion of the average balance of prepayments related to the flexible spending account benefit for employees. Employees can elect to deduct certain amounts from their pay every two weeks to use for medical and child care expenses. However, the expenditures for qualified costs exceed the balance available in the early part of the year and Montana-Dakota funds a prepayment so that employees can use the spending accounts as they incur the costs. The amount of the average prepayment is $15,000 for North Dakota electric operations.

I should note that there are related adjustments for depreciation expense, depreciation reserve and deferred taxes for the rate base adjustments which are quantified by Ms. Mulkern.

Q. Yes. Does this complete your testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case No. PU-399-01-186

Direct Testimony
of
Rita A. Mulkern

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

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

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

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

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

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

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

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

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

EXHIBIT
TRANSCRIPT
12/25/02

45 PU-399-01-186 Pages: 6
Direct Testimony of Rita A Mulkern
by Montana-Dakota Utilities Co., a Division of MDU Re
Exhibit # 6
01/11/2002 CC: Comm Legal Illona, Pat, Jerry Mike .

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

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

A. The purpose of my testimony is to quantify the adjustments to the North Dakota Public Service Commission Staff (Staff) case discussed by Mr. Gaske, Mr. Blinsky, Mr. Gress and Mr. Ball, and the effects of those adjustments on the North Dakota electric revenue requirement. I am sponsoring Exhibit No.___(RAM-1) and Exhibit No. ___(RAM-2) which quantify the effect of these adjustments to the Staff case on the North Dakota electric revenue requirement.

Q. Would you explain Exhibit No. ___(RAM-1)?

A. Yes. The exhibit summarizes the adjustments to the income statement and rate base as supported by the other witnesses. Each of the adjustments was developed either on a total company basis and allocated to North Dakota electric operations or calculated on a North Dakota electric basis.

Q. What does Exhibit No.___(RAM-1) show?

A. Exhibit No. ___(RAM-1), page 1 is a summary showing the income statement and rate of return for 2000, the Staff adjustments and position, Montana-Dakota's adjustments from Exhibit No. ___(RAM-1), and the resulting adjusted income statement, rate of return and revenue deficiency calculation. Page 2 shows similar rate base information

Q. What effect do the adjustments have on the revenue requirement?

A. As shown on Page 1 under the column labeled "Adjusted", Montana-

Dakota's adjusted return on equity is 12.112%, below the 12.75% return on equity required. Montana-Dakota will experience a revenue deficiency of $710,000 at a 12.75% return on equity based on the adjusted calendar year 2000 results.

Q. Does that complete your testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ADJUSTMENTS TO STAFF CASE
2000 TEST YEAR

	Total Company	North Dakota
Revenue		
Pool Sales		($4,266)
O&M		
Demand Penalty	$375	$259
AVS major maintenance	460	317
RTO	563	370
Labor		984
Pension & Benefits		738
Insurance	179	116
Contributions	46	33
		$2,817
Depreciation		$117
Income Taxes		($3,065)
Net Adjustments to Income		($4,135)
Rate Base		
Plant in Service	$5,953	$4,325
Accumulated Reserve for Depreciation		71
Net Plant		4,254
Additions		
Prepayments	23	15
Deductions		
Acc. Deferred Inc. Taxes		65
Adjustments to Rate Base		$4,204

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2000 TEST YEAR

	2000	Staff Adjustments	Staff Test Year	Montana-Dakota Adjustments	Adjusted
Operating Revenues:					
Sales	$79,238		$79,238		$79,238
Sales for Resale	15,034	$2,278	17,312	($4,266)	13,046
Other Operating Revenues	2,691		2,691		2,691
Total Operating Revenues	$96,963	$2,278	$99,241	($4,266)	$94,975
Operating Expenses:					
Production Expense	$38,365	($213)	38,152	$822	38,974
Transmission Expense	3,567		3,567	476	4,043
Distribution Expense	4,660		4,660	267	4,927
Customer Accounts Expense	2,113		2,113	113	2,226
Customer Service & Info. Exp.	105		105	5	110
Sales Expense	269		269	13	282
Administration & General Exp.	8,154		8,154	1,121	9,275
	57,233	(213)	57,020	2,817	59,837
Depreciation Expense	11,803		11,803	117	11,920
Taxes Other than Income	3,811		3,811		3,811
Income Taxes	6,750	1,399	8,149	(3,065)	5,084
Total Operating Expenses	79,597	1,186	80,783	(131)	80,652
Net Income	$17,366	$1,092	$18,458	($4,135)	$14,323
Average Rate Base	$133,667		$133,667	$4,204	$137,871
Rate of Return on Avg. Rate Base	12.992%		13.809%		10.389%
Less: Weighted Cost of LTD	4.737%		3.960%		4.230%
Weighted Cost of Pref. Stock	0.222%		0.240%		0.240%
Weighted Return on Equity	8.033%		9.609%		5.919%
% of Equity to Capital Structure	44.756%		48.870%		48.870%
Return on Equity	17.948%		19.662%		12.112%
Required Return			9.673%		10.700%
Income Requirement			$12,930		$14,752
Pro Forma Net Income			18,458		14,323
Income Deficiency (Excess)			($5,528)		$429
Revenue Deficiency (Excess)			($9,154)		$710

MONTANA-DAKOTA UTILITIES CO.
SUMMARY OF ND STAFF CASE
AND MONTANA-DAKOTA ADJUSTMENTS
2000 TEST YEAR

	2000	Staff Adjustments	Staff Test Year	Montana-Dakota Adjustments	Adjusted
Rate Base:					
Plant in Service	$375,348		$375,348	$4,325	$379,673
Less: Accumulated Depreciation	202,072		202,072	71	202,143
Construct. Work in Prog.	850		850		850
Net Plant in Service	$174,126		$174,126	$4,254	$178,380
Additions:					
Materials and Supplies	3,202		3,202		3,202
Fuel Stocks	1,277		1,277		1,277
Prepayments	209		209	15	224
Total Additions	$4,688		$4,688	$15	$4,703
Deductions:					
Accum. Deferred Income Taxes	41,564		41,564	65	41,629
Accumulated Deferred ITC's	3,074		3,074		3,074
Cust. Advances for Construct.	509		509		509
Total Deductions	45,147		$45,147	$65	$45,212
Rate Base	$133,667		$133,667	$4,204	$137,871

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 9, 2002

Mr. Al Emineth
Emineth & Associates
311 East Thayer
Bismarck, ND 58501

Re: Request for Court Reporter
Case No. PU-399-01-186
Montana Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Emineth:

The Commission requests court reporting services for the hearing in the above captioned case. The hearing is scheduled for February 25, 2002, beginning at 9:00 a.m., in the Commission Hearing Room. A copy of the Notice of Hearing is enclosed.

Montana-Dakota Utilities Company will be responsible for costs associated with the court-reporting service.

If you have questions, please call.

Yours truly,

William W. Binek
Hearing Officer Administrator

WWB/sls
Enclosure

C: Douglas W. Schulz
Donald R. Ball

43 **PU-399-01-186** Pages: 1

Court reporter ordered for 2/25/02 hearing

by Public Service Commission

01/09/2002 CC: Comm Legal PUD (3) Mike ALJ

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

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

Direct Dial No.
(701) 222-7613

RECEIVED
JAN - 9 2002
PUBLIC SERVICE COMMISSION
SECRETARY

January 8, 2002

Mr. William W. Binek
Hearing Administrator
Public Service Commission
State of North Dakota
600 East Boulevard, Department 408
Bismarck, North Dakota 58505-0480

Re: Request for Court Reporter
Case No. PU-399-01-186
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Binek:

Montana-Dakota Utilities Co. hereby requests that a court reporter be present at the hearing in the above case in response to your January 3, 2002 letter. Please make the necessary arrangements. Thank you.

Sincerely,

Douglas W. Schulz
Senior Attorney

cc: Donald R. Ball

42 PU-399-01-186 Pages: 1

Request for a court reporter to be present at hearing
by Montana-Dakota Utilities Co., a Division of MDU R

01/09/2002 CC: Comm Legal PUD (3) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 3, 2002

Mr. Douglas W. Schultz, Senior Attorney
Montana-Dakota Utilities Company
400 North 4th Street
Bismarck, ND 58501

Re: Request for Court Reporter
Case No. PU-399-01-186
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Schultz:

The hearing in the above case has been scheduled for February 25, 2002, beginning at 9 a.m. (CST) in the Commission Hearing Room. The Commission will tape record the hearing. If Montana-Dakota Utilities Company would like a court reporter present at the hearing please notify the Commission in writing within ten days of receipt of this letter and our office will make the necessary arrangements.

The Commission has a contract with the following court-reporting service:

Emineth & Associates
P. O. Box 2655
Bismarck, ND 58502-2655
Telephone: 701-255-3513
Fax: 701-255-6079

Montana-Dakota Utilities Company will pay costs associated with the court-reporting service (i.e. appearance fee, transcript of hearing), and Emineth & Associates will bill for its services as directed by Montana-Dakota Utilities Company.

If you have any questions, please contact us.

Sincerely,

William W. Binek
Hearing Administrator

WWBsls

C: Don Ball, Director of Regulatory Affairs

39 PU-399-01-186 Pages: 1

Letter to MDU re request for court reporter

by Public Service Commission

01/03/2001 CC: Comm Legal PUD (3) Mike ALJ

Affidavit of Publication

State of North Dakota)
)
County of Burleigh)

Laurie Thiel , being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:
MDU Annual Report , 1 time(s)
as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Laurie Thiel

Subscribed and sworn to before me this 14th day of December A.D. 2001.

Laurie Schaffer

LAURIE SCHAFFER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires DEC. 1, 2005

38 PU-399-01-186 Pages: 1

Affidavit of Publication

by North Dakota Advertising Service, Inc.

12/20/2001 CC: Comm Legal PUD (3) Mike ALJ

North Dakota Advertising Service, Inc.

1435 Interstate Loop • Bismarck, ND 58501-0567 • PHONE (701) 223-6397 • FAX (701) 223-8185 • www.ndna.com

INVOICE

Date: 12/18/2001

Page: 1

To:

JON H. MIELKE
PUBLIC SERVICE COMMISSION
STATE CAPITOL
BISMARCK ND 58505

Client: Public Service Commission

Order: 01124PP0

Newspaper	Date	Inches	Page#	Rate	Amount
Ashley Tribune	MDU Annual 12/05/2001	1.00	[Special]	54.60	54.60
Beach Golden Valley News	MDU Annual 12/06/2001	128.00	SPR3	0.50	64.00
Bismarck Tribune	MDU Annual 11/29/2001	95.00	SPR2	0.61	57.95
Bowbells Burke County Tribun	MDU Annual 11/28/2001	1.00	[Special]	50.47	50.47
Bowman County Pioneer	MDU Annual 11/30/2001	1.00	[Special]	57.00	57.00
Crosby The Journal	MDU Annual 11/28/2001	1.00	[Special]	52.17	52.17
Dickinson Press	MDU Annual 11/30/2001	1.00	[Special]	54.60	54.60
Elgin Grant County News	MDU Annual 12/05/2001	1.00	[Special]	57.00	57.00
Ellendale Dickey County Lead	MDU Annual 12/06/2001	1.00	[Special]	54.60	54.60
Hazen Star	MDU Annual 12/06/2001	1.00	[Special]	54.60	54.60
Hettinger Adams County Recor	MDU Annual 12/03/2001	1.00	[Special]	57.24	57.24
Killdeer Dunn County Herald	MDU Annual 11/30/2001	92.00	SPR2	0.57	52.44
LaMoure Chronicle	MDU Annual 12/05/2001	1.00	[Special]	54.60	54.60
Linton Emmons County Record	MDU Annual 12/04/2001	1.00	[Special]	57.00	57.00
Mandan News	MDU Annual 12/06/2001	1.00	[Special]	51.06	51.06
Minot Daily News	MDU Annual 11/29/2001	1.00	[Special]	46.20	46.20
Mohall Renville County Farme	MDU Annual 12/05/2001	1.00	[Special]	57.00	57.00
Napoleon Homestead	MDU Annual 12/05/2001	1.00	[Special]	54.60	54.60
Stanley Mountrail County Pro	MDU Annual 12/05/2001	1.00	[Special]	57.00	57.00
Steele Ozone-Press	MDU Annual 12/05/2001	1.00	[Special]	54.60	54.60
Washburn Center Republican	MDU Annual 12/06/2001	1.00	[Special]	54.60	54.60
Watford City McKenzie County	MDU Annual 12/05/2001	1.00	[Special]	57.00	57.00
Williston Herald	MDU Annual 11/30/2001	99.00	SPR2	0.54	53.46

*** ADVERTISING TOTAL 1263.79

*** TOTAL DUE 1263.79

38 **PU-399-01-186** Pages: 1

Affidavit of Publication

by North Dakota Advertising Service, Inc.

12/20/2001 CC: Comm Legal PUD (3) Mike ALJ .

This invoice is due and payable upon receipt. Unpaid items over 30 days from invoice date are subject to a finance charge. The finance charge is computed by a periodic rate of 1 3/4 percent per month (or a minimum charge of 50 cents for balances of under $50), which is an annual percentage rate of 21 percent. Total unpaid balance may be paid at any time.

Please pay from this invoice — No statement will be sent. Return duplicate with remittance to North Dakota Advertising Service, Inc.

Notice of Hearing, Notice of Public Input Sessions, And Notice of Intervention Deadline

November 21, 2001

Case No. PU-399-01-186

Ashley	12-5
Beach	12-5
Bismarck	11-29
Bowbells	11-28
Bowman	11-30
Center	12-6
Crosby	11-28
Dickinson	11-30
Elgin	12-12
Ellendal	12-6
Hazen	12-6
Hettinger	12-3
Killdeer	11-30
La Moure	12-5
Linton	12-4
Mandan	12-6
Minot	11-29
Napoleon	12-5
Stanley	12-5
Steele	12-5
Watford City	12-5
Williston	11-30

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION
Montana-Dakota Utilities Co. 2000 Electric Operations Annual Report

Case No. PU-399-01-186

NOTICE OF HEARING, NOTICE OF PUBLIC INPUT SESSIONS, AND NOTICE OF INTERVENTION DEADLINE

November 21, 2001

On September 7, 2001, the North Dakota Public Service Commission received a complaint from the North Dakota Public Service Commission Staff (Staff) alleging that Montana Dakota Utilities Co. (MDU), is recovering more revenue than necessary to earn a reasonable return on its investment in North Dakota to provide electric utility service. Staff alleges that MDU's electric service rates should be changed to reduce annual revenue by $9.155 million.

On September 19, 2001, the Commission found that the Staff's Complaint states a prima facie case and that the Complaint should be served on MDU. The Commission believes the public interest requires the Staff's Complaint be investigated. Issues to be considered include:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is MDU's rate of return on its property, used and useful, for the service and convenience in North Dakota?
3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are MDU's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Other relevant information or proposals concerning the proceeding.

A public hearing on this matter will be held beginning February 25, 2002 at 9 a.m. (CST) in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. Anyone wishing to become a party to this proceeding must file a Petition to Intervene by January 25, 2002.

Public input sessions will be held via interactive television on December 11, 2001 at 12:30 p.m. (CST) at locations set forth below. Members of the public are invited to appear and participate in the informal discussions.

The meetings are not considered part of the technical hearing and the discussion at the meetings will not become part of the evidence reviewed by the Commission in making its decision. The discussion will, however, aid the Commission and its staff in identifying the areas of concern to the members of the public.

Bismarck State College
Vocational Technical Ctr Rm 228
1200 College Dr
Bismarck ND

University of North Dakota
Creighton Bldg Rm 109
1410 University Ave
Williston, ND

Dickinson State University
North Campus Rm 104
1679 6th Ave W
Dickinson, ND

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Jon H. Mielke, Executive Secretary, at least 24 hours prior to the hearing.

PUBLIC SERVICE COMMISSION
Anthony T. Clark, Commissioner
Susan E. Wefald, President
Leo M. Reinbold, Commissioner

(December 6, 2001)

"The Lights On For Life" planning committee joined forces with "The Parade of Lights" Greater Downtown Dickinson Association to plan an enjoyable evening for the entire family on Friday, Dec. 7, 2001. The parade will begin at 6:30 starting at 13th Street West and Villard going East to 4th Ave. East turning North to 1st Street and going West to 2nd Ave. West ending at the KDIX building. Santa Claus will lead the parade followed by lighted floats and vehicles.

The candlelight vigil ceremony will begin at approximately 7:15 p.m. at the park on Villard and Sims Street. Everyone is welcome to come to the park for the lighting of the Christmas tree by Santa and listen to Christmas carols sung by the Hagen Junior High Honor Choir, directed by Les Dykema.

Everyone is invited to help celebrate this day by driving with their headlights on during the day to show your support for anti-impaired driving efforts and to

ND Safety Co

This season, choose toys that will make your holiday a safe one. The North Dakota Safety Council offers these tips for selecting toys.

•When choosing a toy, make sure to match the toy to the children's abilities. A toy that is too advanced or too simple for a child

The $400. Dennis D. Blom Memorial Scholarship for OTA students over age 23 is now available. Funds for this scholarship are provided by Roosevelt Memorial (Masonic) Lodge of Belfield. Please obtain applications by contacting Bruce Baer, Belfield Area Dollars for Scholars, at 575-8282. Applications must be returned by 3PM December 21, 2001.

Best wishes through the holidays

May Christmas bring
many blessings to you and yours.
Thanks so much for your devoted patronage.

Wibaux County Nursing Home
Wibaux, MT
406-796-2429

Affidavit of Publication

Golden Valley News
Official Newspaper for Beach and Golden Valley County

DEC 13 2001

STATE OF NORTH DAKOTA,)
County of Golden Valley) ss

I, Debra Walworth, being duly sworn, depose and say that the annexed and printed copy of notice of public notice for MDU

was taken from the Golden Valley News, a newspaper which during the whole time of publication of said notice hereinafter stated, has been and is published in the City of Beach, County of Golden Valley, and State of North Dakota. That said notice was published in said newspaper proper for

1 consecutive week(s) 10 to wit:

Straight Matter Lines	65	$ 65.00	Dec 16, 2001
First Time Line Rate	1.50	$	, 20
Subsequent Line Rate		$	, 20
		$	, 20
Column Inches	X2	$	, 20
First Time Inch Rate		$	, 20
Subsequent Inch Rate		$	, 20
		$	, 20

Total Cost of Legal $ 65.00

Debra Walworth

Subscribed and sworn to before me this 13 day of Dec, 2001

Patti Mushik

Notary Public, State of North Dakota

My Commission Expires

PATTI MUSHIK
Notary Public, State of North Dakota
My Commission Expires 2/9/2007

36 PU-399-01-186 Pages: 1

Affidavit of Publication

by Golden Valley News

12/13/2001 CC: Comm Legal PUD (3) Mike ALJ

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

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

RECEI
DEC -4 2001

December 3, 2001

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Case No. PU-399-01-186
Commissioner Wefald Letter

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. , submits an original and seven (7) copies of this letter in response to Commissioner Wefald's letter of November 5, 2001 relating to off-system sales and the concept of dealing with the volatility of off-system sales revenues through the use of an automatic adjustment clause.

At the outset, Montana-Dakota agrees that off-system sales margins (revenues minus costs) can be very volatile. As such, it would be appropriate to discuss the area as part of this case to determine if any changes from the current practice are appropriate.

The current practice of setting a representative level of off-system sales revenues and costs in a general rate proceeding provides the retail customers with an assured level of benefits regardless of the actual level of off-system sales achieved. If Montana-Dakota is unable to achieve the set level of off-system sales then it is at risk for any shortfall from that level until such time as a general rate case is filed with and approved by the Commission. Conversely, to the extent that Montana-Dakota can make off-system sales above the representative level, both the customers and the Company's shareholders benefit from such off-system sales until a general rate change. The current practice has served to provide rate stability for Montana-Dakota's electric retail customers. The last electric general rate increase was in 1987.

If the off-system sales margins were subject to an automatic adjustment clause process, the changing off-system sales margins (up or down) would be passed on to retail customers which would affect rate stability. Also, there would be no assurance of any level of off-system sales to provide an ongoing benefit.

Montana-Dakota remains open to further discussion of this matter but firmly believes that any such discussions would necessarily focus on the need for incentives and a proper balance of the risks and rewards.

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

Thank you for the opportunity to comment on this important area.

Sincerely,

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

NORTH DAKOTA IVN
INTERACTIVE VIDEO NETWORK

RECEIVED
DEC - 3 2001
PUBLIC SERVICE COMMISSION
LEGAL DIVISION

PO Box 8384
Grand Forks, ND 58202-8384
701-777-6486
Fax: 701-777-6353

Videoconference Confirmation.

This is not a bill.

November 30, 2001

Public Service Commission
600 East Boulevard Avenue
Bismarck, ND 58505

The following event has been scheduled on the North Dakota Interactive Video Network. Please check the details below for accuracy and inform us of any changes that are needed.

Date: December 11, 2001
Time: 12:30-1:30pm
Event #: 3830863
Sites Scheduled: Host – BSC 228, DSU 104, WSC Crtn 109

Telephone Line Charge:	$80 x 1 hours	$ 80.00
Technical Charge:	$10 x 1 hrs x 3 sites	30.00
Total Due NDUS ND Interactive Video Network		**$110.00**

Maps of the sites can be found on http://ndivn.nodak.edu. Click on IVN Sites, then maps to Campus IVN classrooms.

Events cancelled less than 24 hours before the event will be charged the administration and site fee. Sites dropped less than 24 hours before the event will be charged the technical support fee.

Please call the Host Site Coordinator if you are using a laptop, special programs like Power Point, need familiarization with the room, presentation questions, etc. Preparation makes for a successful IVN event.

THANK YOU FOR USING THE NORTH DAKOT

34 **PU-399-01-186** Pages: 1
Videoconference Confirmation
by North Dakota Interactive Video Network
12/03/2001 CC: Comm Legal PUD (3) Mike ALJ

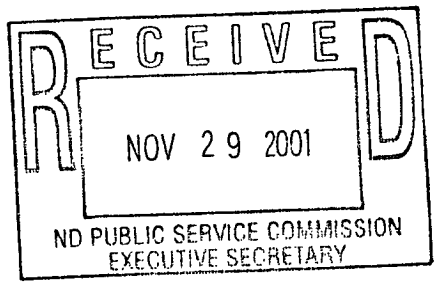
OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.state.nd.us/oah

November 28, 2001



Mr. William Binek
Hearing Administrator
Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

Dear Mr. Binek:

Thank you for your November 27, 2001, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Montana-Dakota Utilities Co. 2000 Electric Operations Annual Report (PU-399-01-0186). I hereby designate myself to be assigned as a administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will actually be making the final administrative decision in regard to this matter (*i.e.*, commission) must actually be in attendance at the hearing.

Please send all additional relevant documents in regard to this matter (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Bismarck, North Dakota 58501-1882. The hearing is scheduled for February 25, 2002, beginning at 9:00 a.m., in the Commission Hearing Room, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota.

Sincerely,

Allen C. Hoberg
Director

ACH:ljc

cc: Douglas W. Schultz

33 **PU-399-01-186** Pages. 1

Allen Hoberg appointed ALJ

by Office of Administrative Hearings

11/29/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

November 27, 2001

Mr. Allen C. Hoberg
Office of Administrative Hearings
1707 North 9th Street, Lower Level
Bismarck, ND 58501

Re: Case No. PU-399-01-186
Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Dear Mr. Hoberg:

Enclosed is a request for an administrative law judge in the above case. The Commission has scheduled a hearing for February 25, 2002, beginning at 9 a.m. (CST) in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck. The administrative law judge will serve as a procedural law judge, a court reporter may be present, and the hearing will be tape recorded. A copy of the case is enclosed.

Please provide the Commission with a copy of any filings issued by your office in this matter.

If you have any questions, please contact me. Thank you.

Sincerely,

William W. Binek
Hearing Administrator

/sls
Enclosure

c: Douglas W. Schultz, Senior Attorney
Don Ball, Director of Regulatory Affairs

32 **PU-399-01-186** Pages: 2

Request for ALJ for Feb 25th Hearing

by Public Service Commission

11/27/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION

NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS

SFN 17819 (Rev. 03-2001)

Name of Agency, Board, or Commission
Public Service Commission

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the hearing in Case No. PU-399-01-186, MDU 2000 Electric Operations Investigation, The hearing is scheduled for February 25, 2002, at 9 a.m. CST in the Commission's 12th floor Hearing Room, State Capitol, Bismarck, ND.

(e.g., application of [name], appeal of [name], petition of [name]). Authority for the administrative action is found in Title 49 (North Dakota Century Code and/or North Dakota Administrative Code).

Please attach related documents and correspondence.

The administrative action is more fully described as follows:

It requests designation of an administrative law judge (please check one):

- ☐ **To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.**
- ☑ **To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).**
- ☐ **To conduct the hearing, issue findings of fact, conclusions of law, and a final order.**

PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact: (Attach separate list if necessary.)

AGENCY Public Service Commission	Address 600 E. Blvd. Ave., Dept. 408, Bismarck, ND	Telephone Number 328-2400
Representation William W. Binek, Chief Counsel	Address Same as above	Telephone Number 328-4088
PARTY Montana-Dakota Utilities Co.	Address 400 N 4th Street, Bismarck, ND 58501	Telephone Number 222-7900
Representation Douglas W. Schultz, Senior Attorney	Address Same as above	Telephone Number 222-7900
PARTY	Address	Telephone Number
Representation	Address	Telephone Number

Additional Comments
The hearing will be tape-recorded and a court reporter may be present.

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested. Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of the notice.)

Typed or Printed Name and Title of Requesting Person William W. Binek, Hearing Administrator	Date 11-27-01
Signature of Requesting Person X	Telephone Number 328-4088

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **23rd day of November, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

> **Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline**

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7099 3220 0002 8482 7757

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **23rd day of November, 2001**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **23rd day of November, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **23rd day of November, 2001**.

Sandra L. Scott

Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

akemp@tminc.com
Ann-Marie Kemp

Lubka@rrnet n
Lewis Lubka
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Fargo ND 58103

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Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
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Gwinner ND 58040-0128

shandy@kwh.com
Scott Handy
Cass County Elec Coop Inc
4100 32nd Ave SW
Fargo ND 58104

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Mark Hanson
Grand Forks Air Force Base
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460 Steen Blvd Ste 201
Grand Forks ND 58205

Karyn Grass
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6620 Denver Club Bldg
518 17th ST
Denver CO 80202-4167

d
d d
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Bismarck ND 58501

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Karen Collins
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400 N 4th St
Bismarck ND 58501

rlogsdon@navix.net
Robert Logsdon
Nebraska Public Service Commission
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Fergus Falls MN 56538-0496

wpp@pearce-durick.com
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Pearce & Durick Attorneys
PO Box 400
Bismarck ND 58502-0400

mdickers@state.nd.us
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tor
2498 59th St
St Anthony ND 58566-9640

Peter Hoff
Arveson Donoho Lundeen Etc
125 S Mill St
Fergus Falls MN 56537

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Data Resource Center
Box 239
Denver CO 80201-0239

Mark Frederiksen
Economic Insights
416 Center St #365
Washington Grove MD 20880

Jay Casler
INDEPTH DATA INC
211 N Robinson Ave Ste S-1500
Oklahoma City OK 73102-7101

Connie Zimmerman
Inoco Inc
Box 177C Rte 4
Williston ND 58801

KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

KCJB AM-FM & KXMC TV
PO Box 1686
Minot ND 58702-1686

Rod Kleinjan
KDIX Radio
119 2nd Ave W
Dickinson ND 58601-5115

KEYZ-AM
PO Box 2048
Williston ND 58802-2048

Jeff Alexander
KFYR-AM Radio
PO Box 1738
Bismarck ND 58502-1738

KHRT AM
PO Box 1210
Minot ND 58702-1210

KLXX AM
4303 Memorial Hwy
Mandan ND 58554

KMOT TV
Box 1120
Minot ND 58702-1120

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KTGO-AM
Box 457
Tioga ND 58852-0457

News Director
KXMA-TV
Drawer B
Dickinson ND 58602

KXMD-TV
PO Box 790
Williston ND 58802-0790

Ron Tipton
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

LeRoy Neubauer
Valley City Public Works
254 2nd Ave NE
Valley City ND 58072

KUMV-TV
PO Box 1287
Williston ND 58802-1287

KXMB TV
Box 1617
Bismarck ND 58502-1617

C W Fox
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Karin Sinclair
Nat'l Renewable Energy Lab
1617 Cole Blvd
Golden CO 80401

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Kim Christianson
Office of Intergovernmental Assist
14th Fl - State Capitol
Bismarck ND 58505-0170

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Friday, November 23, 2001 9:10 AM
To: ndna (E-mail)
Subject: Attached Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline

Colleen
North Dakota Newspaper Association

Colleen,

Please have the attached Notice published as a legal publication in the next issue of the following North Dakota daily newspapers:

Bismarck Tribune
Dickinson Press
Williston Daily Herald

Also publish as a legal publication in the official county newspapers of the following counties:

Adams County
Burke County
Bowman County
Dickey County
Divide County
Dunn County
Emmons County
Golden Valley
Grant County
Kidder County
LaMoure County
Logan County
McIntosh County
McKenzie County
Mercer County
Morton County
Mountrail County
Oliver County
Renville County
Ward County

30 **PU-399-01-186** Pages: 2

Notice e-mailed to NDNA requesting publication by Public Service Commission

11/23/2001 CC: Comm Legal Illona. Pat, Jerry Mike .

Williams County

Please put these in as "News Item Only" articles as well, and send the bill to the Public Service Commission, along with a tear sheet for billing purposes.

If you have any questions, please call me at 328-4076.

Thank you.

Sharon Helbling
Public Utilities Division

11-21-01
:ion for Notice o

APPROVED
DATE: 11-21-01
KME

MOTION

November 21, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission issue a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report, Case No. PU-399-01-186.

sdh

29 **PU-399-01-186** Pages: 1

Motion

by Public Service Commission

11/21/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

NOTICE OF HEARING, NOTICE OF PUBLIC INPUT SESSIONS, AND NOTICE OF INTERVENTION DEADLINE

November 21, 2001

On September 7, 2001, the North Dakota Public Service Commission received a complaint from the North Dakota Public Service Commission Staff (Staff) alleging that Montana Dakota Utilities Co. (MDU), is recovering more revenue than necessary to earn a reasonable return on its investment in North Dakota to provide electric utility service. Staff alleges that MDU's electric service rates should be changed to reduce annual revenue by $9.155 million.

On September 19, 2001, the Commission found that the Staff's Complaint states a prima facie case and that the Complaint should be served on MDU.

The Commission believes the public interest requires the Staff's Complaint be investigated. Issues to be considered include:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

A **public hearing** on this matter will be held beginning **February 25, 2002 at 9 a.m. (CST)** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. Anyone wishing to become a party to this proceeding must file a Petition to Intervene by January 25, 2002.

Public input sessions will be held via interactive television on **December 11, 2001 at 12:30 p.m. (CST)** at locations set forth below. Members of the public are invited to appear and participate in the informal discussions. The meetings are not considered part of the technical hearing and the discussion at the meetings will not become part of the evidence reviewed by the Commission in making its decision. The discussion will, however, aid the Commission and its staff in identifying the areas of concern to the members of the public.

Bismarck State College **Vocational Technical Ctr Rm 228** **1200 College Dr** **Bismarck ND**	**University of North Dakota** **Creighton Bldg Rm 109** **1410 University Ave** **Williston, ND**
Dickinson State University **North Campus Rm 104** **1679 6th Ave W** **Dickinson, ND**	

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Jon H. Mielke, Executive Secretary, at least 24 hours prior to the hearing.

PUBLIC SERVICE COMMISSION

Anthony T. Clark
Commissioner

Susan E. Wefald
President

Leo M. Reinbold
Commissioner

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **21st day of November, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Commissioner Wefald's Letter

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7099 3220 0002 8482 7849

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **21st day of November, 2001**.

Sandra L. Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

27 **PU-399-01-186** Pages: 1

Affidavit of Service

by Public Service Commission

11/21/2001 CC: Comm Legal Illona, Pat, Jerry Mike

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

November 21, 2001

RECEIVED
NOV 21 2001
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Jon Mielke, Executive Secretary
Public Service Commission
State Capitol
Bismarck, ND 58505

RE: Response to Commissioner Wefald's Letter
Case No. PU-399-01-186

Dear Mr. Mielke:

Staff appreciates the opportunity to discuss the issue of off-system sales. Commissioner Wefald has correctly identified the primary issue in staff's complaint case and we are happy to provide input on how the commission should handle the profit from off-system sales.

Staff does not believe the commission needs to change its policy but will address the issues raised.

When establishing MDU's electric rates, the commission allows the company an opportunity to earn a fair return on its investment in North Dakota. Included in that investment are the generation and transmission facilities necessary to provide retail service as well as to make off-system sales. Since the ratepayers are paying a return on these investments through rates, it is easy to understand why ratepayers should receive credit for most, if not all, of the profits from off-system sales.

It seems that the interest in including the profits from off-system sales in the fuel cost adjustment is predicated on the position that off-system sales are volatile and unpredictable. Since 1996, total company profits from off-system sales have increased every year from $1.9 million in 1996 to $9.9 million for the year ending 2000. Off-system sales profits have doubled during the first five months of 2001 compared to the same five months in 2000. The explosive growth in profits from these sales appears to remain.

With these things in mind, staff will address the questions of whether the commission should include off-system sales in the fuel cost adjustment and whether it should consider the use of incentives to encourage the continued marketing of off-system sales.

Fuel Clause Adjustment

The commission's administrative rules for fuel cost adjustments provides for increases or decreases in energy costs incurred by an electric utility less energy costs related to intersystem sales. Therefore, it appears that including off-system sales profits as a cost of energy offset would not comply with existing rules. However, the rules also allow for the commission to deviate from its rules when its use would result in an undue burden. In the end, the commission would need to change its rules or find that the existing framework is an undue burden before implementing a flow through of profits from off-system sales through the fuel cost adjustment.

Incentives

Staff is supportive of regulatory schemes to encourage higher levels of performance. Because of MDU's fiduciary responsibility to its stockholders, companies like MDU can be encouraged to act by designing the proper profit incentives. The difficulty lies in determining to what extent incentives are necessary for the achievement of optimal performance as well as the fair distribution of profits between stakeholders.

Under the commission's current policy, profits from off-system sales are used to offset the cost of providing service. Therefore, the profit margins included in base rates are only established during rate cases. In the case of MDU, rates were last established using a 1986 test year, which likely contained very little profits related to off-system sales in comparison to today's levels. Therefore, stockholders benefit to the extent MDU can outperform margins last included in the development of rates. This kind of built in incentive in rate of return regulation is often referred to as "regulatory lag." It is also worth noting that MDU's ratepayers have benefited from regulatory lag as the increased margins have offset inflationary pressures and the need to raise rates. Given the lengthy period of time since MDU's last rate case, it would be difficult to create a greater incentive to sell more electricity than already exists.

At the other end of the spectrum, requiring an immediate pass through of profits through a monthly billing adjustment would largely reduce the profit incentive to make sales. Under this approach, MDU would still work to

make off-system sales for the purposes of keeping prices down. Keeping prices down is important to economic development activities and the potential for increased sales. Keeping prices down is also important in the event that the electric industry is deregulated and effective competition develops. Still, while some incentives would exist in a pass through environment, the profit motive for increasing off-system sales would certainly be diminished.

Other Commissions' Decisions

The Washington Utilities and Transportation Commission approved Avista Utilities request for deferring certain increased costs related to power supply beginning July 1, 2000, and ending June 30, 2001. Avista positioned itself in a surplus power situation beginning in 2002 and will use the profits from those sales to erase the balance of deferred costs by February 28, 2003. In this special situation, the commission decided to offset the high cost of purchased power during one period of time with the expected profits from off-system sales of another period. *Re Avista Corporation dba Avista Utilities*, 210 PUR 4th 142-144 (WUTC 2001).

The Indiana Utility Regulatory Commission became concerned that PSI Energy, Inc. may be profiting from off-system sales by freeing up generation resources through native load purchases. The commission ordered that an after-the-fact calculation be made to determine the level of profits from off-system sales made from the freed up generation. The profit is distributed to retail customers in the form of a "mitigation credit" allowing PSI to recover its actual net purchased power expenses. *Re PSI Energy, Inc.*, 210 PUR 4th 299, 305, 309 (IURC 2001).

The Florida Public Service Commission removed profits from off-system sales from base rates and established a three-year moving average of profits as the threshold for the application of the shareholder incentive. Under this plan, any profits below the threshold are returned to ratepayers and any profits above the threshold are shared 80% / 20% between ratepayers and shareholders, respectively. *Re Wholesale Power Sales by Investor-owned Electric Utilities*, 204 PUR 4th 544 (FPSC 2000).

The South Dakota Public Utilities Commission approved a tariff revision that allows MidAmerican Energy Company to purchase energy from its South Dakota customers who voluntarily agree to interrupt their firm load for purposes of avoiding high cost purchases or as an opportunity to make off-system sales. The order requires that MidAmerican set up a tracking

account for purposes of accumulating the profits made in these transactions until the next rate case at which time the commission would decide proper treatment. *Re MidAmerican Energy Company*, 203 PUR 4th 538-540 (SDPUC 2000).

The Kansas State Corporation Commission included a normalized level of off-system sales profits in its rate reduction order pertaining to West Plains Energy Kansas. The normalized level reflects an upward trend but does not include the price spikes seen during the summer of 1998. The commission has not established a policy of sharing off-system sales profits but notes that the utility will be able to retain all of the profits above the normalized level. *Re UtiliCorp United, Inc. dba West Plains Energy Kansas*, 198 PUR 4th 397-398 (KSCC 2000).

The North Dakota Public Service Commission granted a natural gas rate increase to Montana-Dakota Utilities Co. in 1982. The increase granted was reduced by projected off-system sales profits. *Re Montana-Dakota Utilities Company*, 46 PUR 4th 195 (NDPSC 1982), Case No. 10,280.

Summary & Conclusion

Staff believes that the current policy of including profits from off-system sales in the establishment of rates is a fair and reasonable approach. The current policy provides a big incentive for MDU to make off-system sales, primarily because of regulatory lag. Because of regulatory lag, MDU has benefited greatly during the past few years as sales have climbed dramatically. However, profits from off-system sales will likely decline as new generation is built. When that occurs, ratepayers will similarly benefit from the other side of the curve.

Staff believes that flowing through profits automatically will eliminate most of the incentive for MDU to continue its high level of sales marketing.

Sincerely,

Mike Diller
Director of Accounting

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OF COUNSEL
HARRY J. PEARCE

November 13, 2001

RECEIVED
NOV 14 2001
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Ms. Illona Jeffcoat-Sacco
Director, Public Utilities Division
North Dakota Public Service Commission
600 East Boulevard Avenue
Bismarck, North Dakota 58505-0480

Re: Case No. PU-399-01-186
Montana-Dakota Utilities Co. Electric Rates Investigation

Dear Ms. Jeffcoat-Sacco:

This will confirm the following agreed procedural schedule for the captioned matter, which resulted from the meeting between Montana-Dakota representatives and you and other members of the Commission staff last week:

Commission Notice of Hearing issued	November 21, 2001
Montana-Dakota Utilities discovery	November 30, 2001
Commission Staff answers to Montana-Dakota discovery	December 10, 2001
Montana-Dakota Utilities prefiled testimony	January 11, 2002
Commission Staff discovery	January 21, 2002
Montana-Dakota Utilities answers to Commission Staff	January 30, 2002
Commission Staff rebuttal testimony filed	February 11, 2002
Montana-Dakota Utilities surrebuttal testimony filed	February 19, 2002
Hearing date	February 25, 2002

25 PU-399-01-186 Pages: 2
Letter confirming procedural schedule
by Montana-Dakota Utilities Co., a Division of MDU Re
11/14/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

• ALSO LICENSED IN MINNESOTA • ALSO LICENSED

Please let me know if this summary differs from your understanding of the schedule reached at the meeting.

Thank you for your cooperation in this matter.

Very truly yours,

William P. Pearce

WPP:pr
Enc.
cc: William W. Binek
Jon Mielke
Donald Ball

Public Service Commission
State of North Dakota

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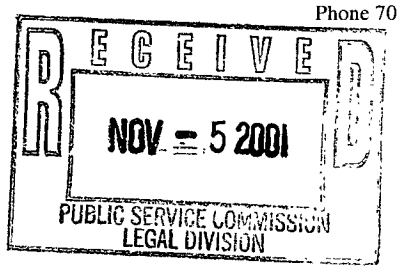
November 5, 2001



Douglas W. Schultz, Senior Attorney
MDU Resources Group, Inc.
PO Box 5650
Bismarck, ND 58506-5650

William W. Binek, Chief Counsel
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

RE: Case PU-399-01-186, MDU 2000 Electric Operations Annual Report
Electric Rates Investigation

Dear Mr. Schultz and Mr. Binek:

This interesting case deals with off-system sales, as well as other issues. I would like the reaction of the parties to the following concept:

Off system sales can involve a great deal of money one year and less money another year . The year to year volatility of off-system sales may be similar to the concept of the fuel cost adjustment, which also may change based on the price of fuel and purchased power.

In researching this issue, I have found two states that have considered dealing with the volatility of off-system sales revenues through the use of automatic adjustment clauses. In *Re Tampa Electric Company,* 142 PUR 4th 538 (Florida Public Service Commission 1993), staff recommended that off-system sales O&M revenues be removed from base rates. The order states, "We voted to accept staff's recommendation and to remove these revenues from base rates and to credit them to the Fuel and Purchase Power Clause because of their variability from year to year." (See attached order.) This order also noted that a separate account was set up to receive capacity revenues that resulted from off-system sales. The Florida Commission noted that they had been exploring incentives related to off-system sales, but at the present time decided that 100% of the revenues from off-system sales should be credited to ratepayers.

See also the Iowa Commission's decision in *Re Iowa-Illinois Gas and Electric Company,* 145 PUR 4th 1 (Illinois Commerce Commission 1993). (See attached section of the case relating to Off-system Electric Interchange Sales Revenue). In this case, the company proposed "an alternative to the traditional treatment of net revenues from off-system interchange sales. The Company proposes that net revenues from off-system sales, both demand charge and energy margins, be shared between customers and the Company through the Fuel Adjustment Clause. Under the company's proposal, 75% of the net demand and energy

Letter re off-system sales

by Public Service Commission by Comm. Wefald

11/05/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

margins system interchange sales would be passed to customers, with 25% being retained by the Company."

The Iowa Commission did not accept this approach since their fuel adjustment charge did not allow this type of pass through.

I welcome staff and MDU comments on the concept of handling off-system sales revenue through adjustment clauses. I am also interested in comments on whether or not the Commission should consider incentives relating to off-system sales revenues. By asking for comments on this issue, I am still recognizing the importance of the other issues in this case, including cost of capital.

Sincerely,

Susan E. Wefald
President

Enclosures

ed ommitments under the CQS tariff
l allow both the Company and the
ıer to more prudently plan gas supply
itments.
he adoption of Order No. 636 by the Fed-
ergy Regulatory Commission ("FERC")
quire continued scrutiny of interruptible
ınd transportation rates. While the CQS
s not ideal, in the Commission's view, it
es a useful option as the gas industry
to the impact of the FERC order.
ccordingly, it is
4184) ORDERED:
The Providence Gas Company shall
ıent the Contract Quantity Service tariff,
, no than April 1, 1993.
The motion to consolidate this docket
ocket No. 2076 is denied.
FFECTIVE AT PROVIDENCE, RHODE
ID ON FEBRUARY 26, 1993 PURSU-
TO AN OPEN MEETING DECISION.
TEN ORDER ISSUED APRIL 12, 1993.

FOOTNOTES

e Transcript of Hearing, February 10, 1993
)-10.
52. Mr. DeMetro later expanded his answer:
ould be the ceiling price, that's not necessary
e everybody's going to get charged . . .. The
ey will get charged will be the lower of the
rice or the price of their alternate fuel at some
t." T. 94.
177.
180.
181.

EDITOR'S APPENDIX

PUR Citations in Text

e Interim Policies for Interruptible Natural
ıs Sales and Transportation, 132 PUR4th 293,
or. 1, 1992.

Re Tampa Electric Company

Docket No. 920324-EI
Order No. PSC-93-0664-FOF-EI

Florida Public Service Commission
April 28, 1993

ORDER amending an electric rate order to clarify a shareholder incentive mechanism established to maximize off-system sales of excess capacity. Commission also corrects errors in the computation of off-system sales revenues and in the amount of construction work in progress included in rate base.

The net effect of the corrections is a $1.456 million reduction in 1994 revenue requirement.

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1. RATES, § 640

[FLA.] Procedure — Rate orders — Correction of computational errors — Clarifications.
p. 539.

2. RATES, § 321

[FLA.] Electric — Correction of computational errors — Net revenue reduction.
p. 539.

3. VALUATION, § 224

[FLA.] Construction work in progress — Times interest earned ratio — Application to rate base — Correction of computational error — Electric utility.
p. 539.

4. REVENUES, § 5

[FLA.] Electric — Off-system sales — Adjustment clause credit — Correction of computational errors.
p. 539.

5. AUTOMATIC ADJUSTMENT CLAUSES, § 30

[FLA.] Credits — Off-system sales — Fuel and purchased power clause — Correction

of computational errors — Electric utility.
p. 539.

6. REVENUES, § 5

[FLA.] Electric — Off-system sales — Excess capacity — Shareholder incentive mechanism.
p. 540.

Before Deason, chairman, and Lauredo, commissioner.

BY THE COMMISSION:

ORDER REVISING 1994 REVENUE REQUIREMENT AND CLARIFYING SHAREHOLDER INCENTIVE

By Petition filed May 22, 1992, Tampa Electric Company (TECO or the company) requested an annual revenue increase of 49.7 million dollars in 1993 and a step increase of 33.5 million dollars to be effective January 1, 1994. On January 4, 1993 we established the 1993 rates based on the $1,163,000 increase approved at the December 16, 1992 special agenda conference. The Final Order reflecting these rates (Order No. PSC-93-0165-FOF-EI) was issued on February 2, 1993. No party requested reconsideration of that Order. The rates for 1994 have not yet been set.

[1-5] In that Order, we included in TECO's 1994 rate base the amount of Construction Work In Progress (CWIP) that would correspond to a 3.75 times interest coverage ratio in 1994 for Tampa Electric Company. On January 12, 1993, the company filed a letter (with copies to all parties) stating that the staff possibly made a mathematical error when computing the 3.75 times interest coverage ratio. After review, we find that the amount of CWIP in 1994 should be increased by $6,947,000 to maintain a 3.75 times interest coverage.

When calculating the interest coverage estimate, staff failed to recognize the rate base impact of the Commission's decision to increase the coal inventory amount to be included in rate base above the staff recommended level. The Commission's decision to increase the amount of coal inventory allowed in rate base was not accounted for by staff when calculating the interest coverage ratio. Based on this oversight, we find that $5,859,000 of additional CWIP shall be allowed in TECO's rate base for 1994.

In addition, the 1994 interest coverage calculation did not reflect the full amount of interest on the oil backout debt. In its letter to the Commission, the company recommended using a 1994 oil backout interest amount of $2,133,000. Based on the record, though, we believe the correct amount of interest to be utilized is $2,033,000, as outlined on page two of Hearing Exhibit No. 123. Applying this cost to the interest coverage calculation increases the amount of CWIP recommended in 1994 by $1,088,000. Based on this correction, we find that $1,088,000 of additional CWIP shall be allowed in TECO's rate base for 1994.

In establishing the amount of CWIP to include in TECO's 1994 rate base, we target the achievement of a 3.75 times interest earned ratio. To maintain this interest coverage, we increase the 1994 CWIP amount by $6,947,000 based on the two above-mentioned adjustments. The total amount of allowed CWIP in 1994 therefore increases from $48,017,000 to $54,964,000. This balance represents $18,793,000 of short-term CWIP and $36,171,000 of CWIP subject to Allowance for Funds Used During Construction. From January 1, 1994 until ordered to modify or cease, the $36,171,000, which is earning a return from this proceeding, shall offset CWIP balances that accrue AFUDC.

At the December 16, 1992 Agenda Conference, we approved staff's recommendation that the Commission exclude $3,888,000 of off-system sales O&M revenue for the 1994 test year from the calculation of the 1994 revenue requirement. On January 12, 1993 Tampa Electric Company filed a letter stating that the staff possibly made a mathematical error when computing the 1994 off-system O&M revenues.

Tampa Electric's original rate case request included off-system O&M revenues as a credit to base rates. We voted to accept staff's recom-

mendation to remove these revenues from base rates and credit them to the Fuel and Purchase Power Clause because of their variability from year to year. When calculating the appropriate O&M revenues to move from base rates to the Fuel and Purchased Power Clause, an incorrect amount was used.

Late Filed Exhibit 106, Schedule C-10 Page 60, reflects $3,888,000 in off-system sales revenues, which included both off-system O&M revenues ($1,349,000) *and* capacity revenues ($2,539,000). The correct amount of O&M revenues from off-system sales credited to the retail jurisdiction should have been $1,349,000, not $3,888,000.

The appropriate adjustment to remove the capacity revenues from the O&M revenues which are to be credited to the Fuel and Purchased Power Clause is to exclude the $2,539,000 in capacity revenues from the calculation. This adjustment results in $1,349,000 of O&M revenues credited to the Fuel and Purchased Power Clause for 1994.

Therefore we find that the amount of off-system sales O&M revenue for 1994 should be reduced from $3,888,000 jurisdictional to $1,349,000 jurisdictional for a difference of $2,539,000.

The net effect of these two corrections (to the amount of CWIP and off-system sales O&M revenue) is a reduction of the 1994 revenue requirement by $1,456,000. Tampa Electric Company shall submit a 1994 compliance ost-of-service study within 10 days of this Order reflecting the revised revenue requirement.

We take this opportunity to amend Order No. PSC-93-0165-FOF-EI to clarify the incentive established for TECO's stockholders to maximize off-system sales of excess capacity.

The discussion of the incentive for off-system sales begins at page 85 of the *Order Granting Certain Increases*. The changes are intended to clarify the scope and duration of the incentive. The following section is substituted for the discussion found under the same heading in Order No. PSC-93-0165-FOF-EI

H. *Appropriate Treatment of Revenues Associated With Off-System Sales, Incentives*

[6] Staff recommended that all capacity revenues from off-system sales should be credited to the Capacity Cost Recovery Clause and that all off-system O&M revenues credited to the Purchased Power and Fuel Cost Recovery Clause. Staff proposed this treatment because of the variability of off-system revenues, which depend on the needs of Tampa Electric's neighboring utilities, the prevailing market conditions, and competing fuel prices. Uncertainty in projecting off-system revenues presents a problem when determining base rates in a rate case.

If in future years, actual revenues are greater than the forecasted amount included in base rate determination, the ratepayers are penalized and the company retains the excess revenues for its stockholders. The opposite is true if actual revenues are less than the forecasted amount benefiting the ratepayers. Since forecasting the revenue impact of future off system sales revenues is difficult because of the numerous assumptions contained in the forecast which may or may not prove accurate over time, staff recommended crediting off-system capacity revenues to the Capacity Cost Recovery Clause, and removing the projected off-system O&M revenues of $2.75 million in 1993 and a revised amount of $1.349 million in 1994 from base rate revenues and crediting these amounts to the Fuel Cost Recovery Clause.

Forecasting levels of off-system sales is far from an exact process. In his testimony, Tampa Electric's witness, Mr. Ramil, projects $11.9 million of nonfuel revenues from off-system transactions in 1993 not including the Sebring and TECO Power Services sales. This is roughly half of the 8 month actual/4 month forecast amount of $23 million of nonfuel revenues for the current year 1992. Tampa Electric will likely have the opportunity for additional off-system sales starting in 1993 when the Hardee Power Station capacity of 295 MW comes on-line.

The revenue effect of incorrectly forecasting off-system sales from year to year will be eliminated if the revenues are credited through the Capacity Cost Recovery and Fuel and Purchased Power Clauses. Our treatment eliminates the potential inaccuracy from forecasting the level of off-system sales to be included in the calculation of base rate revenues.

All revenues and expenses associated with the firm Schedule D sales (for the cities of New Smyrna Beach, St. Cloud and Wauchula, the Reedy Creek Improvement District and the Florida Municipal Power Association), and the City of Sebring and TECO Power Services contracts have been removed from the retail jurisdiction in the stipulated jurisdictional separation study.

Accordingly, we find that all nonfuel revenues from off-system sales not allocated to the wholesale jurisdictional shall be included as credits in the Capacity Cost Recovery and Fuel and Purchased Power Cost Recovery Clauses. The capacity revenues shall be credited to the Capacity Cost Recovery Clause with O&M revenues credited to the Fuel and Purchased Power Cost Recovery Clause. We remove projected O&M revenues from off-system sales of $2,750,000 jurisdictional in 1993 and $1,349,000 jurisdictional in 1994 from base rate revenues.

Tampa Electric has proposed a sharing of the benefits of certain off-system sales described in Mr. Ramil's testimony (modified in accordance with the revised jurisdictional separation), in order to preserve an incentive for engaging in off-system sales which was incorporated in Tampa Electric's last full rate proceeding in Docket No. 850050-EI. TECO claims that retention of this incentive will directly benefit Tampa Electric's retail Customers.

Tampa Electric proposes to retain 60 percent of the capacity revenues from off-system sales other than those in the wholesale jurisdiction for the benefit of their stockholders and flow the remaining 40 percent of these revenues through the Capacity Cost Recovery clause for the benefit of the ratepayers.

Staff recommended that the Commission reject Tampa Electric's proposed 60/40 stockholder/ratepayer sharing of off system sales capacity revenues as unnecessary. Staf suggested that a prudently managed utilit would use its best efforts to market thi capacity and energy irrespective of whether i receives an additional incentive for doing so.

If the Commission decides to explor incentives, staff recommended that this issu be investigated in a generic docket. At tha time, the Commission can explore the issu of off-system sales incentives as well a penalties for low levels of off-system sales o continued high levels of surplus capacity This proceeding would allow the Commis sion the opportunity to adopt a uniforr approach for all companies if it determine that incentives and penalties are needed fc levels of off-system sales of generatin capacity.

We believe that a generic proceeding t consider this issue is appropriate. We direc staff to initiate a docket to investigate an consider stockholder incentives for ofi system sales.

By our decision to credit the nonfue revenues associated with off-system sale through the Capacity Cost and Fuel and Pur chased Power cost recovery clauses, we hav not maintained the status quo for Tamp Electric Company. In addition to the imputa tion of 37.1 million dollars of nonfuel reve nue in the last rate case, in that case w established a sharing of the annual revenue in excess of that amount. The stockholder would have received 20% of the revenu above that level and the ratepayer 80%. Sinc the target level of off-system sales was neve achieved, no sharing ever occurred.

We believe that incentives can be usefi in maximizing the level of off-system sale: Maximizing off-system sales makes the be use of the available capacity and can hel minimize rates. The time necessary to cor duct and decide a generic proceeding t determine an appropriate, industry-wide po icy is likely to yield an effective date (October, 1993 at the earliest. This means th there will be less incentive for TECO to pu sue off-system capacity sales and the carr ing cost of any unused capacity will be pai by the ratepayer.

non-union medical contributions is not determinable.

Mr. Kerckhove distinguished between the union and non-union portions of the Company's proposed adjustment for medical expenses. He noted that the 20% increase in medical contributions for union employees was set forth in a written agreement between the Company and its union employees, while there was no similar written agreement with non-union employees. Staff notes that the Company can deposit into its trust fund for non-union employees' medical expenses any amount that it chooses and can ch the monthly funding at any time.

Staff also indicates that the 20% increase in the medical plan funding for non-union employees is being used to increase the trust fund balance, and not to cover actual medical expenses. Mr. Kerckhove testified that the Company's requested 20% increase in non-union medical funding amounts to $624,382. In contrast, he noted that the actual December 31, 1992, non-union medical plan trust balance was $710,014 less than the Company's desired level (Tr. 533). Staff further notes that Staff Cross Exhibit 7 indicates that the actual medical plan expense for non-union employees of $3,772,812 in 1992 was $379,692 less than the 1992 budgeted amount of $4,152,504, and $29,406 less than the actual medical plan expense of $3,802,218 in 1991. Staff concludes th Company budgeted a 9.2% increase in no. ion medical plan expenses for 1992, but experienced a 0.8% decrease in actual expenses. Staff concludes that the Company has provided no basis to justify increasing its non-union medical expenses for 1993 by 20% (Initial brief, pp. 41-42).

In response to Staff's position, the Company argues that the 20% increase in medical plan contributions for non-union employees is known and measurable. The Company cited its testimony that the 20% increase for both union and non-union employees became effective on January 1, 1993, the increase was being collected from the Company and covered employees, and that the funds were being deposited in a Voluntary Employees' Beneficiary Association ("VEBA") trust to satisfy medical claims and provide a reserve to pay incurred but unreported claims.

The Company also responded to Mr. Kerckhove's distinction that the union portion of the medical plan expense was the subject of a written agreement between the Company and its union employees, while there was no similar agreement with non-union employees. The Company states that the underlying obligation to adequately fund the medical plan and the VEBA trust is based upon the requirements of federal law (the Employee Retirement Income Security Act ("ERISA"), 29 U.S.C. 1101, *et. seq.*), and not upon a union contract. The Company states that the ERISA requirements for prudent and adequate funding apply to both the non-union and union medical plans.

In response to Staff's argument that the 20% increase in non-union medical contributions is being used to increase the medical plan reserve balance and not to cover actual medical expenses, the Company indicates that a portion of the medical contribution increase is being used to restore the medical plan reserve balance. The Company asserts that the medical plan reserve is a prudent and integral part of the medical plan fund balance. The Company notes that the Internal Revenue Code requires that the re serve only be used to satisfy medical plan claims and expenses. The Company indicates that amounts in the reserve cannot be returned to the Company.

Staff disagrees with the Company's contention that the Company needs to restore the medical plan reserve balance. Citing Staff Cross Ex. 6, Staff notes that the December 31, 1992 non-union plan trust balance was $1,063,208, while the corresponding December 31, 1991 balance was $509,553. Staff indicates that the amount of the Company's actual 1992 non-union medical contributions, which is the level allowed by Staff in test year operating expenses, enabled the Company to meet all of its medical expenses and double the balance of its non-union medical plan reserve (Reply brief, p. 6).

Staff does not dispute the Company's claim that funds deposited in a VEBA trust can only be used for the payment of medical claims and expenses. Staff asserts, however, that the Company does not face any restrictions or

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requirements regarding its future funding level.

The Commission concludes that Mr. Kerckhove's proposed adjustment should be rejected. The Company is proposing recognition of a non-union medical contribution increase which has already occurred and will continue at the time the rates in this proceeding become effective. The 20% increase is known and measurable. The Commission does not agree with Staff that the existence of a written contract is sufficient grounds for different treatment of the non-union and union medical expense increases. The Commission notes that Staff's Part 285 arguments would apply to both the non-union and union medical expense increases. The Commission further finds that it is reasonable for the Company to build up its non-union medical plan trust balance. The Company's desired level of that balance does not appear to be excessive.

2. *Off-System Electric Interchange Sales Revenue*

[8-10] Traditionally, the Commission has recognized in electric rates, as a reduction to revenue requirement, the Illinois portion of net revenues (both demand charge and energy margins) from test period off-system interchange sales. Company witness Thomas L. Christensen, its Vice President — Corporate Planning and Regulatory Affairs, refers to this treatment as the "all or nothing" approach. Customers receive credit for off-system sales revenues, net of cost of off-system sales, at the level included in test year revenue requirement, but receive no additional credit when the level of test period margin has been exceeded. Conversely, the Company receives no margin from off-system sales until the test period level of margin is achieved and then receives all the benefit in excess of the level included in the test period.

In this proceeding, Iowa-Illinois proposes an alternative to the traditional treatment of net revenues from off-system interchange sales. The Company proposes that net revenues from off-system sales, both demand charge and energy margins, be shared between customers and the Company through the Fuel Adjustment Clause. Under the Company's proposal, 75% of the net demand and energy margins system interchange sales would be passe to customers, with 25% being retained Company. Mr. Christensen testified Company's proposal is intended to interim approach during the period whe net off-system seller rather than a ne (Iowa-Illinois Ex. I, p. 13).

The Company contends that the tr approach creates needless and unc fluctuations in income. Mr. Christensen that the off-system interchange market competitive market. He indicated that t of off-system sales is determined by m tors, including the capacity that Iowa has to sell, the capacity available fro competitors, unit availability and rela prices (Tr. 182-183). Mr. Christensen st if the Company's proposal had been during 1992, ratepayers would have $2,152,708 in off-system sales revenu rather than the $328,000 which w included in electric rates (Iowa-Illino pp. 7-8).

Staff witness Gould oppos Company's proposal. Mr. Gould pro reflect the 1992 level of $2,876,00(demand charge and energy revenues ir a credit to the revenue requirement. M contended that the Company's propos not provide the same incentive to en off-system sales as the traditional While he agreed with Mr. Christensen' ment that the traditional method described as an "all or nothing" appr indicated that this approach encour Company to make a certain level of of sales or "suffer the consequences." He that the traditional method provides which the Company must meet befo retain net revenues from off-system s Gould contend ed that under the Co proposal, it would have 75% less inc engage in off-system sales. Mr. Gould sized that under the Company's prop Company has no target to meet and w part of the net revenues from every of sale it makes.

Mr. Gould also contended Company's proposal essentially tran

risk associated with forecasting off-system sales from shareholders to ratepayers. He argued that forecasts of off-system sales are necessary under the traditional method which he is proposing. He noted that under the Company's proposal, off-system sales forecasts would be unnecessary.

Staff notes that the trend in the level of the Company's off-system sales revenues has been downward. Staff questions the Company's motives for developing its off-system sales revenue sharing proposal. Staff asserts that in light of this downward trend, the Company fears the re under the traditional approach from over- fo asting the level of off-system sales.

Staff acknowledges that ratepayers would have benefitted if the Company's proposal had been in effect during 1992. Staff emphasizes, however, that there is no guarantee that the Company's proposal will benefit ratepayers in the future.

Staff witness Garrett E. Gorniak, an Audit Senior in the Auditing Section of the Accounting Department of the Commission's Public Utilities Division, also addressed the Company's proposed treatment of net revenues associated with off-system interchange sales. He proposed an adjustment which included in the Company's test year revenue requirement the 1992 level of revenues and related expenses attributable to off-system sales that were p nted in the Company's updated filing. His a ment, which is supported by Mr. Gould, increases test year electric operating revenues and power production expenses by $7,364,000 and $4,494,000, respectively (Staff Ex. 4.1, Sch. 4(E)). Mr. Gorniak testified that the Company has included a forecasted level of various test period items in its cost-of-service, such as sales, operation and maintenance expenses and general and administrative expenses. He indicated that a level of off-system sales and related expenses can also be forecasted for the test period. He indicated that off-system sales and related expenses can vary from year to year like any other test period item. He concluded that there is no reason to single out off-system revenue and sales margin just because they may vary from the forecasted amount in future years. He indicated that these items should be included in cost-of-service as are all other items.

In response to Mr. Gould's criticism that the Company's proposal would reduce its incentive to engage in off-system sales, the Company points out that its proposal provides it with the incentive of retaining 25 cents of every dollar of off-system sales. The Company contends that its proposal would permit it and its ratepayers to benefit from whatever sales are achievable in a competitive market.

In response to Mr. Gould's position that the Company's proposal transfers the risk associated with forecasting off-system sales from shareholders to ratepayers, the Company asserts that forecasting is irrelevant to either its proposal or Mr. Gould's proposal. The Company points out that under Mr. Gould's proposal, the level of 1992 off-system sales, not forecasted sales, is recognized in rates.

Iowa-Illinois acknowledges that the downward trend in off-system sales revenues was one factor which it had considered in making its proposal. Iowa-Illinois also recognizes that if an unachievably high level of historical sales were embedded in base rates, Iowa-Illinois could only lose under the traditional approach. Iowa-Illinois states that if the trend in off-system sales revenues continues downward, it could only be harmed by Staff's proposal and never benefitted. The Company also indicates that if the downward trend were reversed and off-system sales increased above the amount included in cost-of-service, customers would see no additional benefit.

The Company also notes that Mr. Gould agreed that if its proposal had been implemented in the nine-year period from 1984 through 1992 following its 1982 rate case, customers would have received credit for approximately $22,350,000 in off-system sales revenues, rather than the $2,952,000 credit that they actually received. The Company contends that this amply demonstrates the opportunity for customers to benefit under its proposal. In response, Staff points out that there is no guarantee that similar results will occur in the future.

Finally, Staff contends that neither Section 9-220 of the Act nor 83 Ill. Adm. Code 425, Uniform Electric Fuel Adjustment, allows the fuel clause flow-through of off-system revenue margins that the Company is proposing.

In deciding this issue, it is first necessary to determine whether or not Part 425 directly or indirectly permits the flow-through of off-system sales margins proposed by the Company. The Commission notes that Part 425 does not contain any specific provision for including this item in determining the fuel adjustment charge ("FAC"). Furthermore, Section 425.50 states that "The automatic reconciliation factor (Ra) will consist of the difference between actual allowable costs incurred and FAC recoveries for each month . . .." The FAC is fully tracking in that the Ra factor insures recovery of all under-recoveries and refund of all over-recoveries of fuel cost. The term "FAC recoveries" in the explanation of the Ra factor in Section 425.50 does not include revenues from off-system sales because this revenue is not produced by energy billings to service classifications subject to fuel adjustment in the Company's tariffs (as applicability is described in Section 425.10). Finally, the cost to produce and deliver the electricity to generate off-system sales (which is the other component of margin from off-system sales) is specifically removed from the determination of the FAC in the formula in Section 425.30, and therefore, does not come within the definition of "actual allowable costs incurred" in Section 425.50. The Commission, therefore, concludes that the Company's proposal is not consistent with the provisions of Part 425 and cannot be accepted. In light of this determination, other arguments concerning the treatment of off-system sales revenues will not be addressed. Staff's proposed treatment of off-system sales revenues is accepted.

3. *Nuclear Outage Costs*

[11] Iowa-Illinois owns a 25% interest in Quad-Cities Nuclear Station Units 1 and 2, with the remaining 75% interest owned by the operator, Commonwealth Edison Company (Edison). These two nuclear units are on alternating 18-month refueling cycles. As a consequence, in each three year period, one of the units will incur outage costs in the first year, the other unit will incur outage costs in the second year, and both units will incur outage costs in year. To mitigate the significant exper tion in every third year caused by two outages, Iowa-Illinois utilizes reserve ing to establish a nuclear outage reserve. Iowa-Illinois bases this reser forecast outage costs provided by Edis

The nuclear outage reserve reco the test period contains provisions f uled 1993 and 1994 refueling out Quad-Cities Units 1 and 2. Estimat 1993 and 1994 outage costs were pro Edison, but were stated in 1992 cons lars. In developing its test period outag provision, Iowa-Illinois adjusted Ediso constant dollar estimates to recognize actual payment of the outage expenses occur until 1993 and 1994 when costs higher as a result of inflation. Iowa-Illi cates that it adjusted the 1992 consta estimates for anticipated inflation of 4% and 4% in 1994.

While Staff did not object Company's use of an outage reserve, ness Gorniak did object to Iowa-Illinoi ment of Edison's 1992 constant dollar for anticipated inflation in 1993 and 19 contends that the Company's inflatio ment to the 1992 constant dollar estim vided by Edison is not a known and me change as required by 83 Ill. Adm 285.150(e). Mr. Gorniak's propose lowance of the inflation factor woul electric operation and maintenance exp $68,000 (Staff Ex. 4.1, Sch. 3(E)).

Mr. Gorniak noted that Edison's e were provided in early October 1992. cated that the refueling outage in 1993 i uled for March. He asserted that since eling outage in 1993 is scheduled to o months after Edison provided its estim inflation factor applied by the Compan on an annualized basis (Tr. 245-246). St cates that since the 1994 outage is sche take place 15 months after the date of estimate, the Company has actually a 13.1% annualized inflation factor to estimate for the 1994 outage (Initial 36).

In its briefs, Staff notes that 83 Il

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **18th day of October, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Errata to Staff's Testimony

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7000 0520 0022 8655 3896

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **18th day of October, 2001**.

Notary Public

SEAL

CHARLENE A. MAGSTADT
Notary Public, State of NORTH DAKOTA
My Commission Expires Jan. 7, 2004

23 **PU-399-01-186** Pages: 1

Affidavit of Service

by Public Service Commission

10/18/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Memo

To: Jon Mielke, Executive Secretary

From: Mike Diller, Director of Accounting

Date: October 18, 2001

Re: Errata to Staff's Testimony in Case No. PU-399-01-186

Attached are replacement pages to staff's original testimony filed with the commission on September 7, 2001. The changes are not material to staff's complaint case against MDU but submitted here for accuracy purposes.

Page 2 of the original filing included a table of contents. The page numbers in the table were incorrect. This filing includes a corrected table of contents.

Pages 9 and 10 are also included as replacement pages. In its original filing, staff incorrectly concluded that MDU had moved away from a single peak allocation factor in favor of 12CP. In reality, both the staff and MDU advocated the use of 12CP in MDU's last rate case. As the replacement pages indicate, the arguments in that case revolved around which data set to use rather than the method employed. In the last rate case, the commission accepted the use of 12CP. The Company currently uses 12CP to allocate system wide demand costs as well as for reporting purposes to the commission. For this proceeding, staff takes no exception to MDU's continued use of 12CP.

Thank you for your patience in this matter.

Mike Diller

Mike Diller, Director of Accounting

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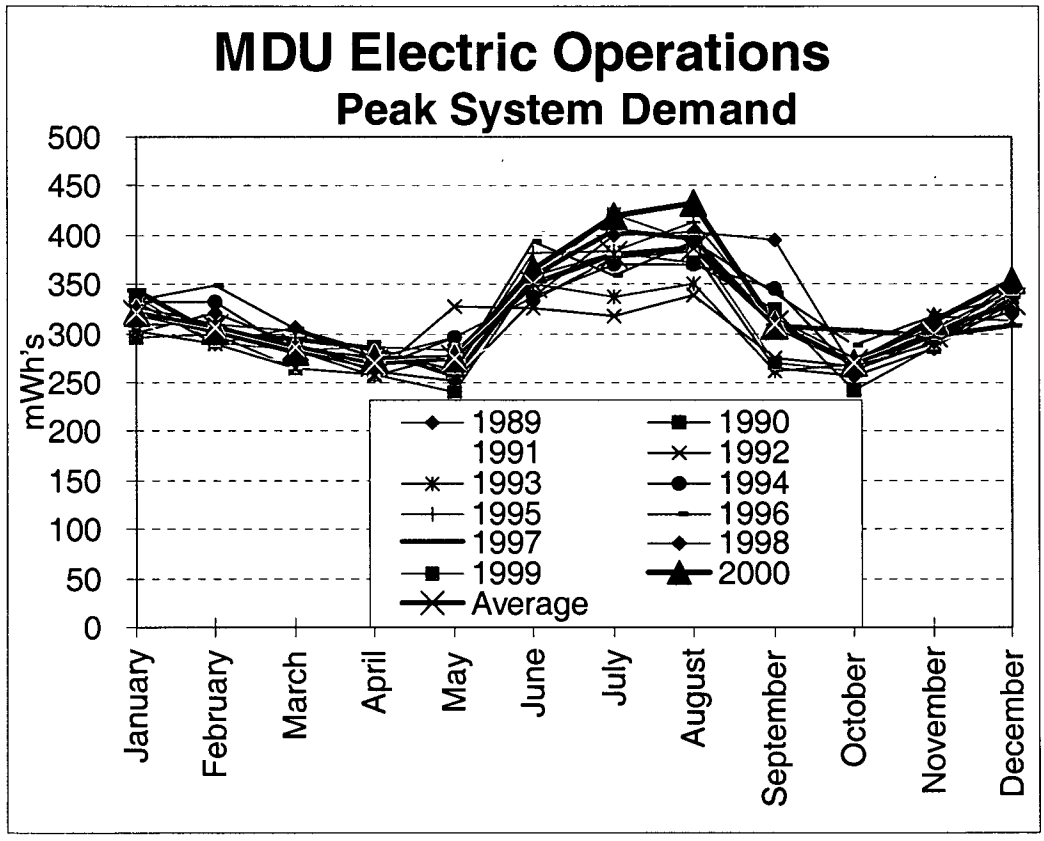
are non-utility in nature and should be properly allocated its fair share of costs to avoid cross-subsidization from the utilities operations. Staff argued that space related costs should be allocated based on square feet rather than a formula developed by the Company. The Commission agreed and so ordered. For this proceeding, staff reviewed MDU's accounting for service and repair operations procedures (effective January 1, 1997) noting that all space related costs are allocated based on occupied floor space.

Another cost allocation issue arose over the allocation of system wide demand costs. Both MDU and the Commission staff used the 12 coincident peaks (12CP) method for allocating demand costs. However, differences arose as to which factor was best for allocating the projected 1986 test year costs. In its rate increase application, MDU introduced evidence using a year ending June 30, 1985 demand allocation factor whereas staff argued for a year ending December 31, 1985 factor. For rebuttal purposes, MDU also introduced evidence for using data from the year ending June 30, 1986. The Commission concluded "apparently the Company has recently used June 30 or December 31 data in each jurisdiction it operates in a manner that maximizes allocation of plant to that jurisdiction. The result has been allocation of more than 100 percent of rate base."

In this case, staff is not advocating the use of a different method or a different data set for allocating demand costs. Staff will accept the

demand allocation factor used by MDU to allocate its demand costs and to report its earnings to the Commission for the year ending December 31, 2000. Following is a chart depicting the peak system demand for MDU's electric system since 1989.



After reviewing the pattern of monthly peaks for both NSP and OTP, staff has concluded that MDU's pattern of monthly peaks more closely resembles those of NSP. NSP's electric demands peak in the summer whereas OTP's electric demands peak in the winter. In the case of NSP, the Commission approved the use of 12CP in NSP's last electric rate case. It appears from the demand data that a single peak approach

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

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

OCT 9 2001
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

October 9, 2001

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Electric Rates Investigation
Case No. PU-399-01-186

Enclosed for filing please find an original and seven (7) copies of Montana-Dakota Utilities Co.'s Answer in the above referenced case.

Sincerely

Douglas W. Schulz
Senior Attorney

Enclosure

21 PU-399-01-186 Pages: 4
Answer
by Montana-Dakota Utilities Co., a Division of MDU Re
10/09/2001 CC: Comm Legal Illona, Pat, Jerry Mike

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

Montana-Dakota Utilities Co., Case No. PU-399-01-186
A Division of MDU Resources Group, Inc.
Electric Rates Investigation

ANSWER

COMES NOW, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., 400 North Fourth Street, Bismarck, North Dakota 58501, and for its Answer to the Complaint herein:

1. Admits the allegations of Paragraph I.

2. Admits the allegations of Paragraph II.

3. Admits the allegations of Paragraph III but affirmatively alleges the conclusions drawn from such investigation are erroneous, unfounded and incorrect.

4. Admits the allegations of Paragraph IV but affirmatively alleges Staff's beliefs are erroneous, unfounded and incorrect.

5. Denies the allegations of Paragraph V and affirmatively alleges, pursuant to Section 49-05-04.1, NDCC, that it may opt for a test year other than as set forth in the Complaint herein.

6. Denies the allegations of Paragraph VI.

7. Admits the allegations of Paragraph VII.

WHEREFORE, Montana-Dakota respectfully requests that the Complaint herein be dismissed.

Dated this 9th day of October, 2001.

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

By: Douglas W. Schulz

Douglas W. Schulz
Senior Attorney
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

VERIFICATION

I, Donald R. Ball, the undersigned Director of Regulatory Affairs for the Answering Party, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., do hereby affirm that the statements contained in the foregoing Answer are true and correct to the best of my knowledge and belief.

Donald R. Ball
Director of Regulatory Affairs

SUBSCRIBED AND SWORN to before me this 9th day of October 2001.

Janel Britton, Notary Public
Burleigh County, North Dakota
My Commission Expires: 5/8/04

JANEL BRITTON
Notary Public
State of North Dakota
My Commission Expires May 8, 2004

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Answer upon counsel for Complainant by hand delivering a true and correct copy thereof to him at his current office as follows:

William W. Binek
Chief Counsel
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, ND 58505-0480

Dated this 9th day of October, 2001.

Donald R. Ball

Donald R. Ball
Director of Regulatory Affairs

Donald R. Ball
Director of Regulatory Affairs
Montana-Dakota Utilities Co.,
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **20th day of September, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Complaint

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501
Cert. No. 7099 3220 0002 8481 1947

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **20th day of September, 2001**.

Sandra L Scott
Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

20 **PU-399-01-186** Pages: 1

Affidavit of Service to serve Complaint on MDU
by Public Service Commission

09/21/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

APPROVED
DATE: 9-19-01
KMF

MOTION

September 19, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission find that the complaint states a *prima facie* case, and serve the complaint on Montana-Dakota Utilities Co.

19 PU-399-01-186 Pages: 1

Motion - Complaint states a prima facie case & serve complaint on MDU by Public Service Commission

09/19/2001 CC: Comm Legal illona, Pat, Jerry Mike .

APPROVED
DATE: 9-19-01
KME

MOTION

September 19, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission appoint Jerry Lein as advocacy staff, and Illona Jeffcoat-Sacco and Patrick Fahn as Commission advisors in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

Sdh

18 PU-399-01-186 Pages: 1

Motion appointing Lein as advocacy staff / Illona & Fahn as Commission advisors by Public Service Commission

09/19/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

September 7, 2001

RECEIVED
SEP - 7 2001
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Jon Mielke, Executive Secretary
Public Service Commission
State Capitol, 12th Floor
Bismarck, ND 58505-0480

Dear Mr. Mielke,

The Public Service Commission staff has completed its investigation of MDU's electric operations using a historical 2000 test year. Staff has concluded that MDU should be required to reduce its retail electric rates by approximately 11% to recover $9.155 million less in annual revenues from North Dakota ratepayers.

Enclosed is an original and seven copies of staff's Complaint as well as the testimony of staff witnesses Mike Diller and Charlie King.

Sincerely,

Mike Diller

Mike Diller
Director of Accounting

C: Don Ball, Montana-Dakota Utilities Co.

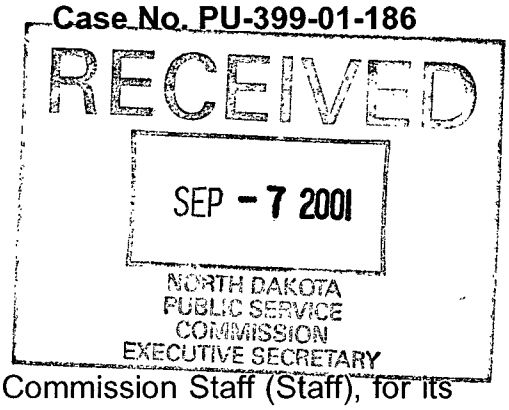
17 PU-399-01-186 Pages: 1
Cover letter re Complaint
by Public Service Commission by Mike Diller, Director
09/07/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

STATE OF NORTH DAKOTA

BEFORE THE PUBLIC SERVICE COMMISSION

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

Case No. PU-399-01-186



COMPLAINT

COMES NOW, the North Dakota Public Service Commission Staff (Staff), for its complaint against Montana-Dakota Utilities Co. (MDU), alleges:

I.

That MDU is a division of MDU Resources Group, Inc., a Delaware Corporation, duly authorized to do business in the State of North Dakota as a foreign corporation, and that it is doing business in the State of North Dakota as an electric distribution public utility.

II.

The North Dakota Public Service Commission (Commission) has regulatory jurisdiction over the rates, services and practices of MDU within the State of North Dakota.

III.

Staff has conducted an investigation of MDU's electric financial operations and its reported return on equity.

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Complaint
by Public Service Commission
09/07/2001 CC: Comm Legal Illona, Pat, Jerry Mike

IV.

Based upon its investigation, Staff believes that MDU's rates for electric services are unjust and unreasonable in that MDU is recovering more revenue than necessary to earn a reasonable return on its investment in North Dakota.

V.

MDU's rates for electric service should be decreased by $9.155 million annually based on its 2000 annual report for electric service rendered to customers in the State of North Dakota.

VI.

MDU's rates for electric service should be decreased to a level that will provide MDU the opportunity to earn a just and reasonable rate of return on its electric property devoted to providing service to its North Dakota electric customers.

VII.

This Complaint is submitted in accordance with Commission authority under Title 49 of the North Dakota Century Code and the rules and regulations promulgated by the Commission.

WHEREFORE, Staff respectfully requests:

1. That the Commission determine that the rates charged by MDU for electric service to customers in the State of North Dakota are excessive.
2. That the Commission determine the appropriate rate base for MDU's electric operations in North Dakota.
3. That the Commission determine the rate of return for MDU's electric operations in North Dakota.

4. That the Commission adjust MDU's rates to provide an opportunity for MDU to earn a reasonable return on its electric operations in North Dakota.

5. That the Commission determine the appropriate rate design for MDU's electric operations in North Dakota.

6. That MDU be required to implement rates to reduce annual revenues by $9.155 million.

7. For such other and additional relief as the Commission shall deem just and proper.

Dated this 7th day of September, 2001.

William W. Binek
Chief Counsel

RECEIVED
SEP - 7 2001
NORTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Direct Testimony

Mike Diller

Before the **North Dakota Public Service Commission**

Montana-Dakota Utilities Co.

North Dakota Electric Operations

Case No. PU-399-01-186

Staff Investigation of Excess Earnings

EXHIBIT
TAKEN
1
2/25/02

August 2001

15 PU-399-01-186 Pages: 40
Direct Testimony of Mike Diller
by Public Service Commission
Exhibit # 1
09/07/2001 CC: Comm Legal Illona, Pat, Jerry Mike

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Qualifications

Q: PROVIDE YOUR NAME AND POSITION AT THE PUBLIC SERVICE COMMISSION.

A: My name is Mike Diller and I am the Director of Accounting. I am responsible for the Commission's accounting and data processing operations and any assigned public utility matters.

Q: PROVIDE A SUMMARY OF YOUR EDUCATIONAL BACKGROUND AND PUBLIC UTILITY REGULATORY EXPERIENCE.

A: I have more than 17 years of public utility regulatory experience including service for both the Oklahoma Corporation Commission and the North Dakota Public Service Commission. I received a Bachelor of Science Degree in Accounting from Oklahoma Christian College in Edmond, Oklahoma in 1981. I am a Certified Public Accountant licensed in the state of Oklahoma, and I am a member of the American Institute of Certified Public Accountants.

Q: HAVE YOU PROVIDED TESTIMONY IN NORTH DAKOTA BEFORE?

A: Yes. I have testified before the Commission on telephone acquisition proposals, rate cases, offers of settlement and other issues.

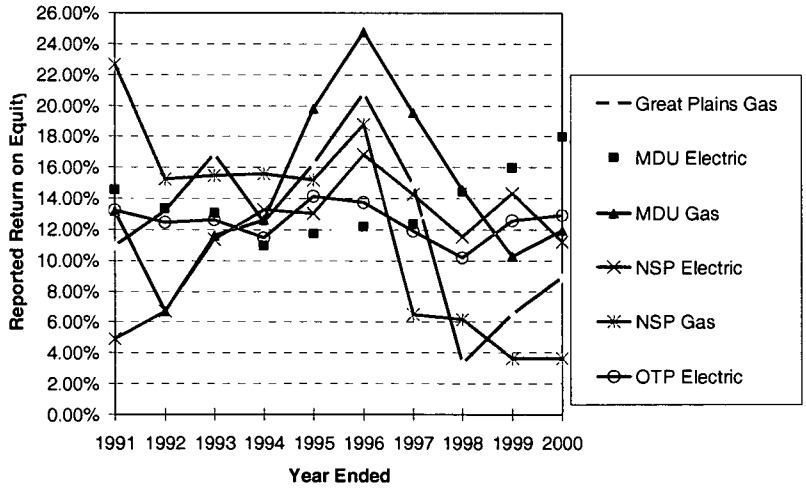
Summary

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The Commission requested that staff conduct a financial review of the electric operations of Montana-Dakota Utilities Co. (MDU). The request was made after MDU reported a return on equity of 15.94% and 17.95% for 1999 and 2000, respectively. My testimony presents the results of staff's review.

Q: HOW DO THE EARNINGS OF MDU'S ELECTRIC OPERATIONS COMPARE TO THE REGULATED EARNINGS OF OTHER UTILITIES REGULATED BY THE COMMISSION?

A: The earnings of MDU's electric operations do not fluctuate like those of the regulated gas operations in the state. In fact, MDU's earnings were quite stable at or around a 12% return on equity. However, earnings began to increase substantially in 1998 as sales for resale increased. A historical summary of MDU's actual electric earnings compared to the other regulated gas and electric companies in North Dakota follows:



Q: PROVIDE A SUMMARY OF YOUR FINDINGS.

A: Based on the most recent annual report to the Commission for the year ended 2000 and using the last authorized return on equity of 12.71%, Montana-Dakota Utilities Co. (MDU) over-collected $5 million in North Dakota during 2000. The 12.71% return on equity was established in 1987 as a result of MDU's last rate increase application. However, the current economic times do not require such a high return on equity. Staff believes an 11.2% return on equity is adequate to fairly compensate today's investors. Based on an 11.2% return on equity and other staff adjustments, MDU is significantly over-collecting from its ratepayers. Staff recommends that MDU's retail electric rates be reduced by about 11% or an annual reduction in revenues of $9.155 million.

Q: WHAT HAS CHANGED SINCE THE LAST RATE CASE TO CAUSE MDU TO OVER-EARN?

A: The primary reason MDU is over-earning today is that profits from its sales for resale have skyrocketed. Not only has demand for electricity increased but the price others are willing to pay for it has increased as well. The additional profits from sales for resale along with a lower cost of capital and a lower investment base have caused MDU to over-earn.

Rate Design

Q: HOW DOES STAFF RECOMMEND THAT THE RATE REDUCTION BE

ALLOCATED TO THE VARIOUS CUSTOMER CLASSES?

A: Staff has not reviewed a class cost of service study and therefore recommends an across the board rate reduction unless otherwise recommended and successfully argued by MDU. Staff's position is one of expediency and therefore staff remains open to other suggestions by the commissioners or other parties to this case.

Rate of Return Regulation

Q: DESCRIBE HOW YOU REACHED YOUR CONCLUSION THAT MDU'S RATES SHOULD BE REDUCED.

A: My conclusion is based on rate of return regulation using MDU's actual reported results for the year ended 2000. In setting rates for MDU, the Commission must consider the financial integrity of the Company as well as the consumer's rights to dependable and reliable service at reasonable rates. To balance the interests of both, the Commission has relied on rate of return regulation. Rate of return regulation essentially involves the regulation of profits. Profit regulation can be justified in the absence of competitive markets. However, once a competitive market emerges, there is no need for rate of return regulation.

Rate of return regulation is comprised of 3 primary components including rate base, cost of capital and net operating income. Rate base comprises the various types of capital investments necessary to provide

service in North Dakota such as plant, materials and supplies. The cost of capital component captures the overall weighted cost of long-term debt and shareholder equity and is expressed in percentage form. The rate base multiplied times the weighted cost of capital equals the amount of profit needed to pay for the cost of debt and shareholder equity. Lastly, net operating income displays net profit from regulated operations including the various types of revenues and expenses generated by MDU's North Dakota electric operations.

Given these three components, one can determine whether the rates are too high or too low and whether the rates need to be adjusted. The rate base multiplied by the cost of capital provides the necessary return on investment. The required return on investment compared to the net operating income determines to what extent rates should be changed, as follows.

Revenue Deficiency Calculation

(Thousands)

Description	(CN 10799) TY 1986	Reported 1998	Reported 1999	Reported 2000	Test Year 2000
Average Rate Base	$140,256	$134,189	$134,869	$133,667	$133,667
ROR Required	10.88%	10.35%	10.49%	10.65%	9.67%
Return Required	$15,259	$13,882	$14,151	$14,232	$12,929
Return Earned	$12,855	$14,821	$15,999	$17,366	$18,457
Return Deficiency (Excess)	$2,404	($938)	($1,848)	($3,134)	($5,528)
Tax Factor	1.818	1.656	1.656	1.656	1.656
Revenue Deficiency (Excess)	$4,378	($1,554)	($3,060)	($5,190)	($9,155)

Test Year

Q: WHAT TEST YEAR DID STAFF USE IN ITS INVESTIGATION AND WHY?

A: Staff used the most recent historical year ending December 31, 2000. Recently, state legislation was passed that specifically allows utilities companies regulated by the Commission to choose historical test years or even multiple projected test years in its rate applications. Staff has chosen to use a historical test year. Using a historical test year still requires that an analysis be done to determine if such revenues and costs are reasonably expected to continue during the time rates are in effect.

Cost Allocation

Q: DO YOU AGREE WITH MDU'S ALLOCATION OF COSTS TO NORTH DAKOTA'S ELECTRIC OPERATIONS FOR THE TEST YEAR ENDED 2000?

A: Staff agrees to use MDU's allocation of jurisdictional costs in this proceeding. In this case, staff has determined to not pursue a detailed analysis of MDU's cost allocation methods and processes. However, it is still necessary to address what has been done in the past and identify any subsequent changes that have occurred.

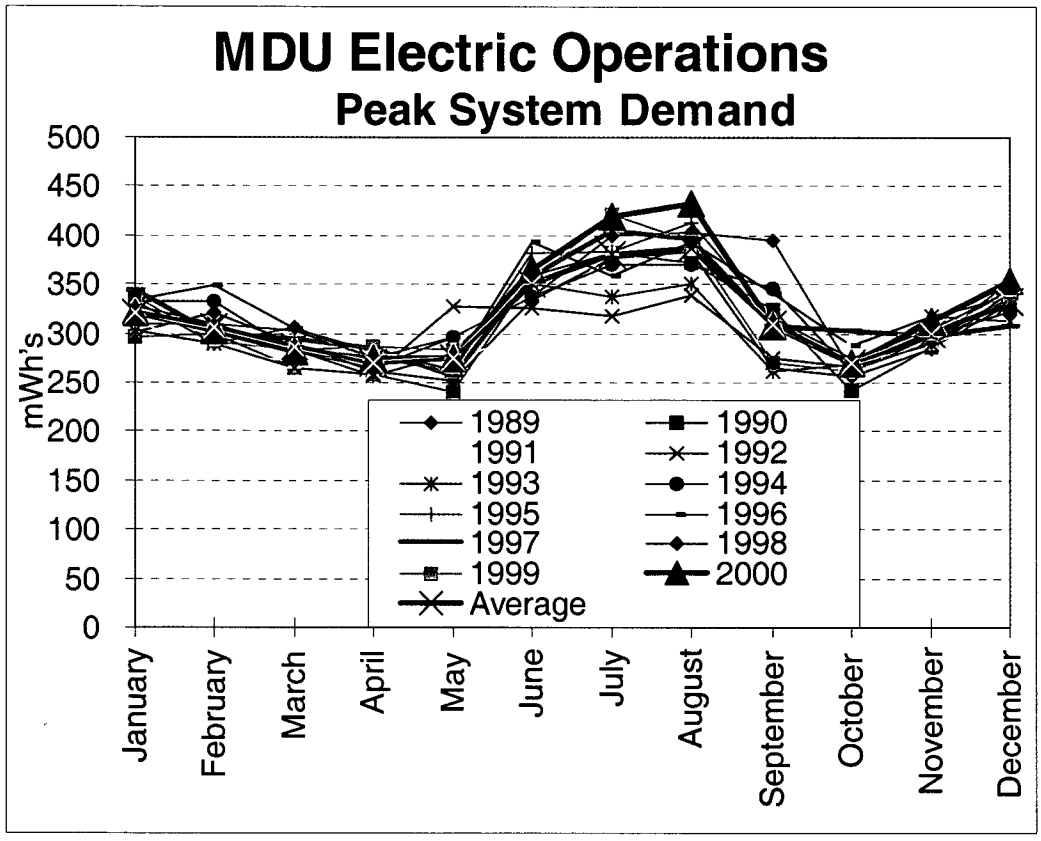
In the last rate case, staff argued that MDU's merchandising operations

are non-utility in nature and should be properly allocated its fair share of costs to avoid cross-subsidization from the utilities operations. Staff argued that space related costs should be allocated based on square feet rather than a formula developed by the Company. The Commission agreed and so ordered. For this proceeding, staff reviewed MDU's accounting for service and repair operations procedures (effective January 1, 1997) noting that all space related costs are allocated based on occupied floor space.

In the last rate case, staff also argued for the use of a calendar year-end 1985 peak demand allocation factor rather than a June 30, 1985 peak demand factor for the projected 1986 test year as requested in MDU's rate increase application. In its order, the Commission concluded "apparently the Company has recently used June 30 or December 31 data in each jurisdiction it operates in a manner that maximizes allocation of plant to that jurisdiction. The result has been allocation of more than 100 percent of rate base."

For the past 5 years, MDU has allocated demand costs on a monthly basis to all jurisdictions using 12 coincident peaks (12CP). As a result, the concerns expressed by the commission regarding over-allocation of demand related costs are largely dismissed. Since jurisdictional demand information is not available when costs are being allocated each month, MDU allocates demand costs by using the 12CP factor from the previous year.

Staff reviewed MDU's peak electric system demands and questions the decision to move away from a single peak allocation to 12CP. Following is a chart depicting the peak system demand for MDU's entire electric system since 1989.



After reviewing the pattern of monthly peaks for both NSP and OTP, staff has concluded that MDU's pattern of monthly peaks more closely resembles those of NSP. NSP's electric demands peak in the summer whereas OTP's electric demands peak in the winter. In the case of NSP, the Commission approved the use of 12CP in NSP's last electric rate case. It appears from the demand data that a single peak approach

could be argued but for purposes of this proceeding, staff is agreeable to the use of 12CP. Staff also reviewed the historical allocation of rate base and other expenses for unusual fluctuations in allocation percentages to North Dakota. Having completed that review, staff does not believe any adjustments are necessary for this proceeding.

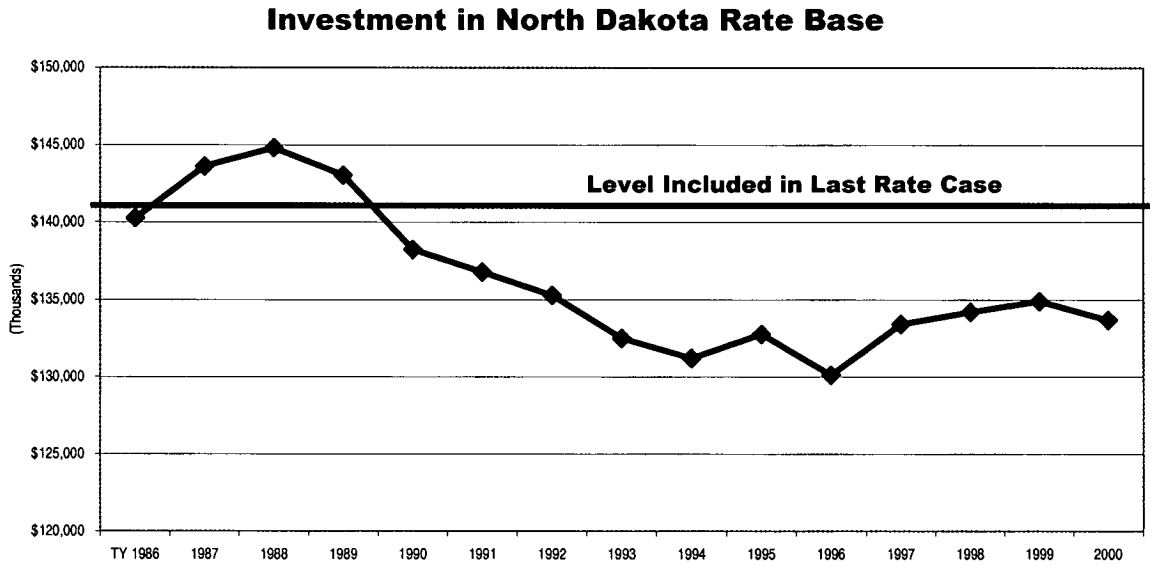
Rate Base

Q: WHAT COMPONENTS ARE INCLUDED IN RATE BASE?

A: In its annual reports to the Commission, MDU includes plant in service, accumulated reserve for depreciation, construction work in progress, materials and supplies, fuel stocks, prepayments, accumulated deferred income taxes, accumulated investment tax credits and customer advances. The following worksheet gives some historical perspective for each component including staff's recommended rate base amount.

	(Thousands)				
	(CN 10799)	Reported			Test Year
Description	TY 1986	1998	1999	2000	2000
Plant in Service	$259,898	$359,461	$366,890	$375,347	$375,348
Accum. Res. for Depreciation	87,017	184,135	193,286	202,071	202,072
Avg. Net Plant in Service	$172,881	$175,326	$173,604	$173,276	$173,276
Constr. Work in Progress		517	2,572	850	850
Materials & Supplies	2,621	3,271	3,252	3,202	3,202
Fuel Stocks	1,457	1,305	1,192	1,277	1,277
Prepayments	413	249	265	209	209
Net Negative Salvage	2,247				
Accum. Def. Income Taxes	(28,253)	(42,366)	(42,124)	(41,564)	(41,564)
Accum. Invest. Tax Credits	(11,092)	(4,105)	(3,583)	(3,074)	(3,074)
Customer Advances	(18)	(8)	(309)	(509)	(509)
Average Rate Base	$140,256	$134,189	$134,869	$133,667	$133,667

As you can see from the worksheet, the rate base has diminished since the last rate case contributing to the current over-earnings of MDU. This is illustrated in the following chart of total rate base since the last rate case.



Q: DO YOU AGREE WITH THE COMPONENTS INCLUDED IN MDU'S REPORTED RATE BASE?

A: Similar components were included in the Commission's decision in the last rate case using a 1986 test year. For purposes of clarification, I do need to specifically address three areas including construction work in progress, net negative salvage and cash working capital.

In the last rate case order (Case No. 10799), construction work in

progress (CWIP) was not specifically listed so the above rate base schedule gives the impression that the Commission did not include CWIP in rate base. However, a review of the case indicates that the 1985 base year plant in service balance from which the 1986 test year plant in service balance was derived did include $402,000 of CWIP. Therefore, the inclusion of CWIP today does not represent a change in philosophy. MDU continues to include CWIP in rate base that is finished and in service but not yet reclassified as plant in service. Such expenditures require an outlay of cash and should be included in rate base.

Net Negative Salvage

Secondly, the description "Net Negative Salvage" as described in the above rate base schedule reflects the cost in excess of book value to retire and dismantle several old generating stations included in the 1986 rate case. The costs associated with these plants were amortized over a 5-year period and are no longer applicable for this proceeding.

Cash Working Capital

Finally, cash working capital (CWC) is a component normally included by other companies regulated by the Commission. However, CWC was not included by the Commission in its last rate case order or by MDU in its annual reports to the Commission.

In past years, the Commission's practice with MDU has been to disallow cash working capital absent a lead-lag study to support its inclusion.

Yet, in past Commission decisions the rate bases of Otter Tail Power Company and Northern States Power Company have been adjusted "downward" for cash working capital. OTP includes a CWC component, using a lead-lag approach, in its annual report to the Commission. Staff has included CWC in its many settlements with OTP using a lead-lag approach. Even though CWC is not normally included in NSP's annual report, a rate base reduction for CWC, using a lead-lag approach, was included by staff and agreed to by the Commission in its last gas rate investigation (PU-400-95-559) as well as NSP's recent gas rate increase application (PU-400-00-521). With respect to NSP's last "electric" rate case (PU-400-92-399), the Commission reduced NSP's rate base for a negative CWC allowance using a lead-lag approach. As you can see, including CWC typically has benefited North Dakota ratepayers in other cases.

Cash working capital is a calculated level of cash needed to pay ongoing operating expenses. Because revenues are often collected in advance of expenditures, CWC can be a source of cost free capital and therefore a reduction to rate base. A lead-lag study measures the leads and lags of revenues in relation to expenditures.

In the past, MDU has contended that it is unable to do a lead-lag study and that hiring consultants to do the study would be costly. MDU theorizes that the resulting study would render approximately the same results (zero cash working capital required) and therefore result in an

unnecessary cost to ratepayers. MDU contends that none of its other jurisdictions require the inclusion of CWC using a lead-lag study.

In its last review of MDU's gas operations (Case No. PU-399-96-325), staff determined that a lead-lag study was necessary to ensure that MDU receive the same regulatory treatment as other regulated utilities operating in North Dakota. In that case, staff witness Randy Allen determined that the proper level of CWC was a negative $549,000. Staff reached a settlement in the case so the issue was never fully scrutinized. If the case had been fully litigated, it is quite probable that the difference between including zero cash working capital, by default, and the negative $549,000 position would have been less. For purposes of discussion, a rate base reduction of $549,000 reduces the revenue requirement from customers by about $100,000. Due to the immaterial impact to customers observed in the last gas rate investigation and the cost to complete one in this case, staff did not pursue a cash working capital adjustment in this proceeding.

After reviewing the last order and MDU's current annual report for 2000, staff agrees with the components included in rate base.

Q: PROVIDE AN OVERVIEW OF EACH RATE BASE COMPONENT.

Net Plant in Service

A: In recent years, the net plant in service balance (plant in service less

accumulated reserve for depreciation) has remained relatively stable. Essentially, plant in service is being depreciated and retired at about the same rate as plant additions occur.

Construction Work in Progress

The 1999 reported balance of construction work in progress is quite high in comparison to the last rate case and recent years. According to MDU's Response No. 13, Attachment A, the primary reason for the high balance in 1999 is due to the development of MDU's "Mobile Up System." The hardware and software for this system was placed into service in June 2000 for a total cost of about $1.6 million. Mobile Up uses computers and wireless communications systems to link the service dispatch and central call center to every service truck. The 2000 balance is more in line with prior year's balances and reflects a more normal level.

Material & Supplies

The account includes material purchased for construction, operation and maintenance purposes. The balance of material and supplies necessary to provide service has increased 24% since the 1986 test year.

Fuel Stocks

The fuel stock account includes the cost of fuel on hand including transportation and other expenses directly assignable to cost of fuel. The fuel stock inventory value declined in 1995 and has since remained in the

range of $1.2 to $1.3 million.

Prepayments

Expenses such as insurance often require prepayment and are properly included in rate base. Since the last rate case, prepayment balances have declined.

Accumulated Deferred Income Taxes

Accumulated deferred income taxes represent cost free capital made available to MDU primarily through accelerated depreciation for tax purposes. Because of accelerated depreciation for tax purposes, MDU has not been required to remit all the income taxes it has collected from ratepayers. Since the last rate case, MDU's accumulated deferred income taxes balance has grown from $28 million to $42 million. However, in recent years, North Dakota's accumulated deferred income taxes balance has remained relatively constant.

Accumulated Deferred Investment Tax Credits

Accumulated deferred investment tax credits also represent cost free capital to MDU and therefore are a reduction to rate base. The Revenue Act of 1971 requires a sharing of the investment tax credits benefits between ratepayers and investors. In MDU's case, ratepayers receive a reduction for the un-amortized balance of investment tax credits and MDU receives non-utility income for the amortized amounts. The rate base offset continues to decline because the Tax Reform Act of 1986

repealed the investment tax credit provisions under prior law. In recent years, the accumulated investment tax credits have been amortized at a rate of about $.5 million per year. These tax credits will be fully amortized on December 31, 2012.

Customer Advances

Customer advances for construction includes any cash advances made by customers for construction projects. Again, this money represents a source of cost free capital to MDU and therefore is properly deducted from rate base.

Rate Base Summary

After reviewing the individual components of rate base and comparing trends since the last rate case, staff believes that MDU's 2000 rate base is fairly stated for the purpose of setting fair and reasonable rates for electric service provided in North Dakota. The largest rate base components of net plant in service and accumulated deferred income taxes have been quite stable in recent years.

Cost of Capital

Q: WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE COST OF CAPITAL INVESTED IN NORTH DAKOTA ELECTRIC OPERATIONS?

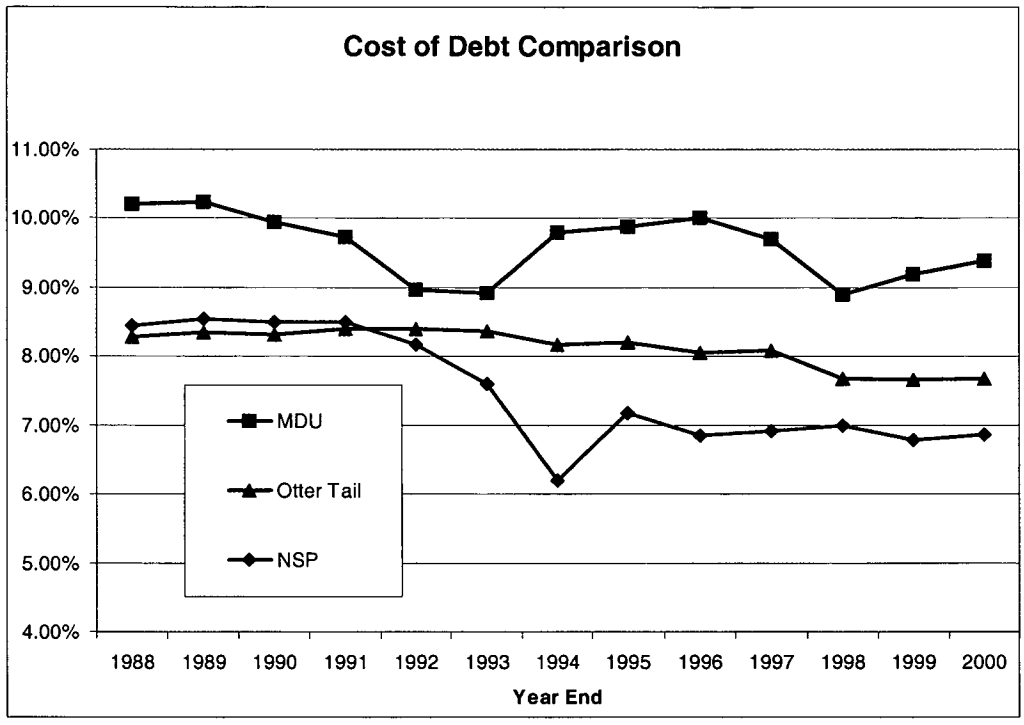
A: MDU should be allowed to earn a reasonable return on its investment.

The appropriate cost of capital is a weighted cost giving consideration to the Company's debt, preferred stock and common equity. Staff's cost of capital consultant Charlie King will testify as to the appropriate cost of capital and capital structure. However, I will also address the cost of debt so as to give some background information.

Debt

In the past, staff has expressed some concern about MDU's overall cost of debt. In staff's last financial investigation of its gas operations, staff witness Legler recommended that the Company consider exploring refinancing opportunities. In addition, I submitted staff's Request for Information No. 20 asking why MDU's average cost of debt was 9.9% in 1995 compared to 8.2% and 7.2% for Otter Tail Power Company and Northern States Power Company, respectively. I noted in my request that a one-percentage point change in the overall cost of debt changes the annual revenue requirements for MDU's North Dakota gas operations by $125,000. MDU responded on October 28, 1996 that it does not have any detailed knowledge of OTP's cost of debt or NSP's cost of debt and therefore cannot explain the differences.

Since the gas operations investigation, the Commission has received several annual reports and the difference between the cost of debt for NSP and OTP is consistently lower than MDU's cost of debt, as can be seen in the following chart.



The cost of debt becomes a bigger issue in this proceeding because MDU's electric business is more capital intensive than its gas business. Instead of an impact of $125,000 as mentioned above, a one-percentage point change in the overall cost of debt changes the annual revenue requirements for MDU's North Dakota electric operations by about $700,000. Staff witness Charlie King addresses the cost of debt in his testimony. Based on King's testimony, the Commission should adopt staff's proposal to use a lower cost of debt than has been reported for the year ending 2000.

Cost of Capital Summary

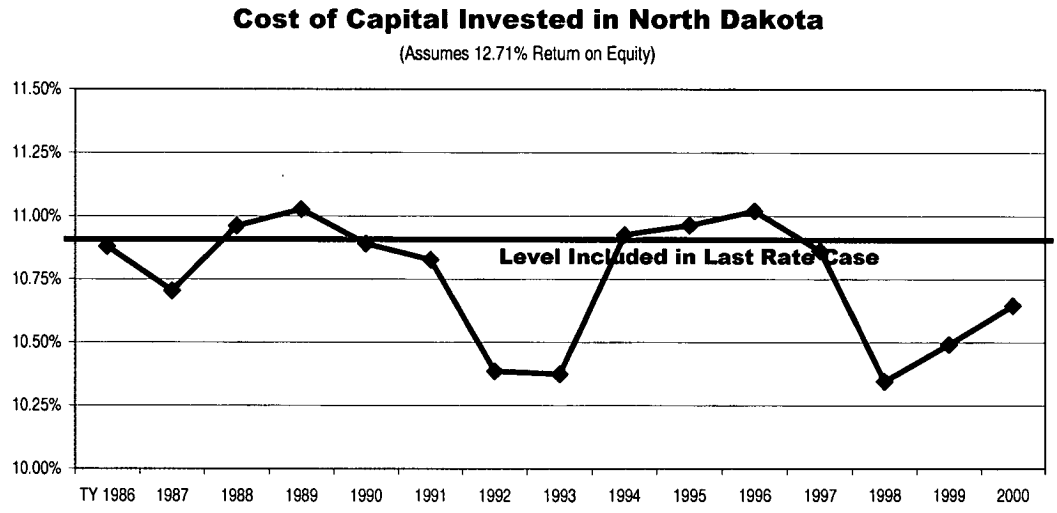
Q: PLEASE SUMMARIZE YOUR TESTIMONY REGARDING MDU'S

OVERALL COST OF CAPITAL.

A: Based on the testimony of Charlie King, staff recommends an overall weighted cost of capital of 9.67%, as follows:

	Test Year 2000			
Long-Term Debt	$144,894	45.90%	8.62%	3.96%
Preferred Stock	16,500	5.23%	4.63%	0.24%
Common Equity	154,250	48.87%	11.20%	5.47%
TOTAL	$315,644	100.00%		9.67%

Like rate base, the overall cost of capital has decreased since the last rate case thereby contributing to the over-earnings of MDU. The following graph depicts the change in overall cost of capital.



Net Operating Income

Q: PROVIDE A LIST OF THE COMPONENTS INCLUDED IN THE DETERMINATION OF REGULATED EARNINGS (NET OPERATING INCOME).

A: The components include revenue from various customer classes, operating expenses, depreciation and taxes as shown below.

	(Thousands)				
	Case No. (CN 10799)	Reported			Test Year
Description	1986	1998	1999	2000	2000
Residential	$32,003	$32,347	$32,099	$31,916	$31,916
Small Commercial	33,926	17,329	17,170	17,275	17,275
Large Commercial		26,148	26,667	26,840	26,840
Public Street Lighting	1,458	1,456	1,451	1,420	1,420
Sales to Public Authorities	1,334	1,221	1,180	1,141	1,141
Other Operating Revenues		2,669	2,373	2,691	2,691
Unbilled Revenue	1,162	(49)	(283)	646	646
Sales for Resale		7,889	13,265	15,034	17,312
Total Revenues	$69,883	$89,010	$93,922	$96,963	$99,241
Cost of Fuel & Purchased Pwr	$21,333				
Other O&M:					
Production Expense		$35,161	$37,160	$38,365	$38,152
Transmission Expense		3,493	3,667	3,567	3,567
Distribution Expense		4,099	4,586	4,660	4,660
Customer Accounts		2,034	2,162	2,113	2,113
Customer Service & Info.		84	96	105	105
Sales Expense		192	258	269	269
Administration & General		8,602	8,303	8,154	8,154
Total Other O&M	$19,321	$53,665	$56,232	$57,233	$57,020
Depreciation	$8,751	$11,206	$11,436	$11,803	$11,803
Taxes Other Than Income	$2,935	$3,832	$3,936	$3,811	$3,811
Income Tax Expense	$4,688	$5,486	$6,319	$6,750	$8,149
Net Regulated Income	$12,855	$14,821	$15,999	$17,366	$18,457

Revenues

Q: PLEASE EXPLAIN YOUR APPROACH TO REVIEWING AND ANALYSING REVENUES.

A: Because MDU does not weather normalize revenues and because staff does not have the resources necessary to develop a weather normalization model of its own, staff began by reviewing each revenue category

for unusual fluctuations. As can be seen from the worksheet above, many of the revenue categories have not fluctuated much in the last 3 years indicating some stability in revenue collections. Staff did note a moderate increase in revenue collections from large commercial customers but not enough to suggest an adjustment for setting rates.

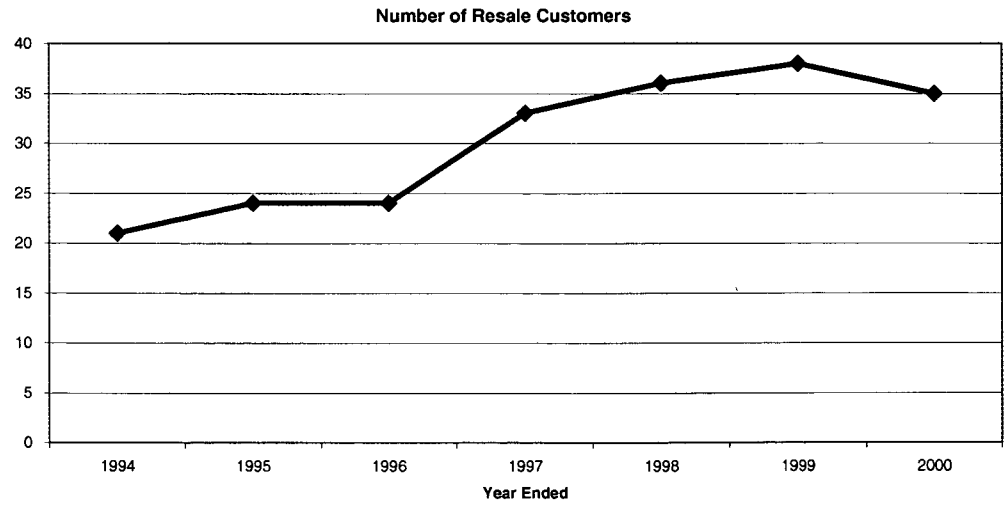
Staff also noted approximately a $300,000 dip in other operating revenues for 1999 in comparison to both 1998 and 2000. Other operating revenues are comprised of three accounts including rent from electric property, miscellaneous service revenues and other electric revenue. According to the FERC Form 1 most of the difference occurred in the other electric revenue account. According to MDU's data response, the dip in 1999 revenues occurred because FERC ordered a refund related to transmission system service charges billed to non-members of MAPP for deliveries off system after traveling through the MAPP transmission system. The refund amount was $352,269 and recorded against the other electric revenues account. Thus it appears that 1998 and the test year 2000 level of other electric revenue represents a more normal level than 1999. Therefore, no adjustment is necessary to staff's test year.

You can also note from the above worksheet that unbilled revenues have fluctuated from one year to the next. Unbilled revenues represent the difference between calendar month deliveries and billing cycle sales. The recording of unbilled revenues therefore restates revenues to recognize sales that have occurred during the year but have not been billed.

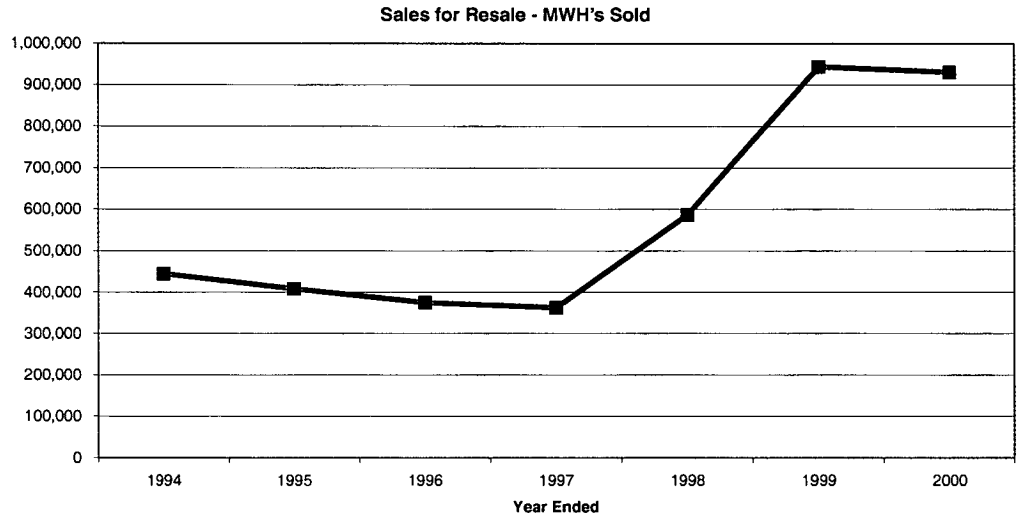
To get a true picture of the revenues earned each month, the company adjusts the cycle billing revenue amounts by adding revenues that have not been billed yet and subtracting those revenues that were actually earned last month. As a result of this process, the year end unbilled revenue amounts represent the change in unbilled revenues from one year to the next. For example, the unbilled revenue for December 1999 was less than the unbilled revenue for December 1998 resulting in negative unbilled revenue for 1999. Conversely, December 2000 unbilled revenue was greater than December 1999 unbilled revenue giving rise to a positive unbilled revenue adjustment. Staff agrees with the process of adjusting revenues to reflect actual revenues earned.

Sales for Resale

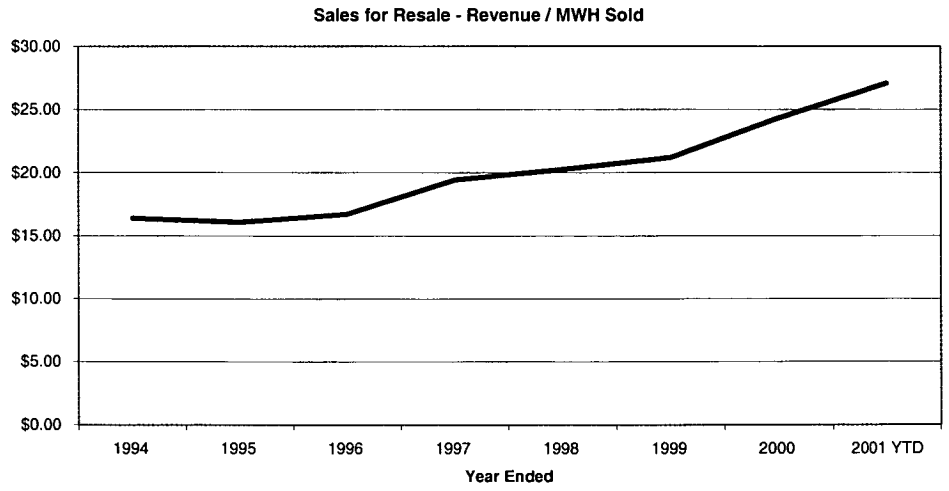
The primary driver of revenue change in recent years has been MDU's sales for resale. The following chart depicts the recent trends in customer numbers.



As you can see, customer levels have been increasing with the exception of a slight decrease for the year ending 2000. That being the case, volumes sold continue to be very strong, as shown in the next graph.

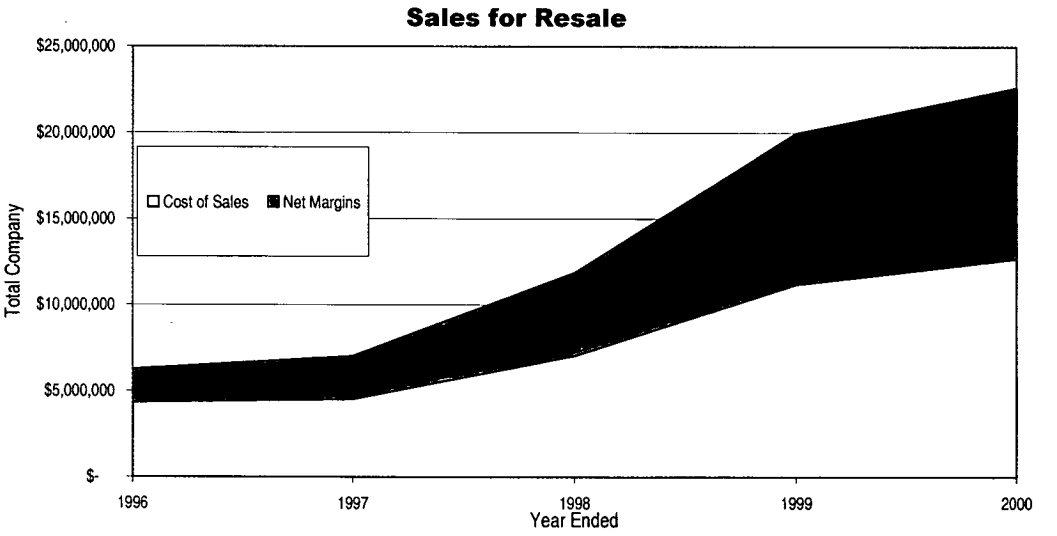


The growth in volumes has nearly tripled since 1997. In addition to strong sales, MDU has experienced substantial growth in revenues per kilowatt hour, as shown in the following graph.



With the combination of explosive growth in volumes and significant increases in the market price of electricity, it is easily understood why revenues from these sales has grown so much.

While revenue growth has been substantial, it doesn't mean much by itself. Even though the ratepayers support the infrastructure necessary to make sales for resale, the company still incurs the variable costs of fuel and purchased power to generate the electricity sold. Therefore, it is critical to review the net margins (revenues less related fuel costs and purchased power) to determine what kind of impact the sales are having on MDU's earnings. The following graph depicts the growth in net margins of sales for resale since 1996,



As you can see above, margins have been rapidly expanding. The growth in margins has caused much of the over-earnings of MDU. Because of the rapid growth, staff believes an adjustment is necessary to

capture known and measurable changes that have occurred in 2001. Failure to recognize the continued growth will result in setting rates that are immediately too high. Therefore, staff makes the following adjustment to its 2000 test year.

	(A)	(B)	(A-B)		
	000's Omitted		Total Co.	N.D.	N.D.
Revenue Adjustment:	2001	2000	Adj.	Share	Adj.
First 5 Months Sales for Resale	$ 10,847	$7,419	$3,428	66.45%	$2,278
Production Expense Adjustment:					
First 5 Months Sales for Resale	$ 4,114	$4,435	$ (320)	66.45%	(213)

In making this adjustment, staff has restated its actual 2000 test year revenues and fuel costs to reflect the continued growth in profits from sales for resale through May 2001. While an argument could be made for a larger adjustment to capture continued growth throughout the entire year of 2001 since the eventual rate reduction will probably not go into effect until after 2001, staff will not propose such an adjustment. For monthly details of sales for resale, see attached Scedule MRD-1.

Q: WHY ISN'T STAFF MAKING AN ADJUSTMENT TO INCLUDE ADDITIONAL EXPECTED SALES FOR RESALE PROFITS FOR THE REST OF 2001?

A: First, it is difficult to predict to what extent sales for resale will continue to grow. The historical growth of these sales suggests further adjustments could be made but staff has chosen to take a more conservative approach. Secondly, staff is aware that MDU must contend with rising

costs as does the commission and other business entities. For example, MDU's 2001 average wage increase of 4.32% added $574,000 in annual revenue requirements to its North Dakota electric operations yet staff will not make an adjustment to recognize the higher costs. Thirdly, it is conceivable that MDU should be allowed to retain some level of additional profit related to these sales for resale. Given the past growth trend, I believe limiting staff's adjustment through May 2001 will adequately address these issues and even provide additional funds for other inflationary needs.

Q: SINCE THE RATEPAYERS ARE PAYING A RETURN ON THE INFRASTRUCTURE NECESSARY TO MAKE SALES FOR RESALE, WHY WOULD YOU SUGGEST THAT MDU BE ALLOWED TO RETAIN A PORTION OF THE PROFITS?

A: I believe that positive reinforcement is better than negative reinforcement. The answer may vary from analyst to analyst but depends on one's belief about what causes people and corporations to act. To make my point, let's assume two extreme positions. In one scenario, MDU is allowed to keep all profits from all sales for resale forever. With the sales for resale market like it is, MDU might divert more attention to further develop its play in the market. This would be an example of very aggressive and positive reinforcement to provide an incentive for MDU to pursue more sales. On the other hand, what if all such profits are immediately captured and returned to the ratepayers. In such a case, it

would not be natural for MDU to spend additional resources to increase sales for resale profits. Spending more money absent a profit motive would run counter to MDU's fiduciary responsibility to its stockholders. This would be an example of negative reinforcement. In this scenario, it doesn't matter how well or poorly MDU performs because it isstill compensated the same. Somewhere between these two examples is the right answer. My recommendation is one of many that could be developed in this regard.

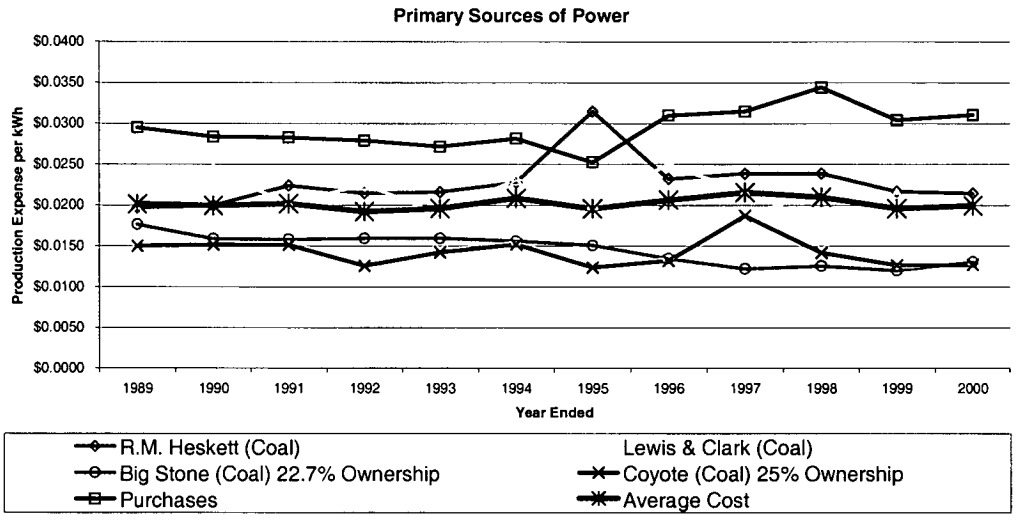
Production Expense

Q: Did staff make any adjustments to the production expense as reported in MDU's 2000 annual report?

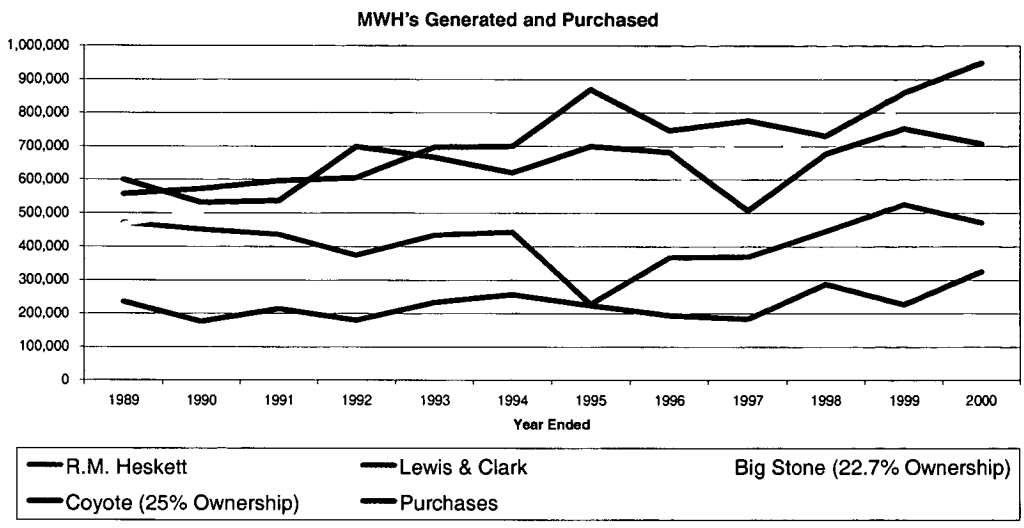
A: Staff only made one adjustment to production expense to correspond with its sales for resale revenue adjustment. Even though production expense has seen some healthy increases in recent years, so have sales and revenues. Additional sales require additional electric production. During the past 3 years, production expense has been quite stable in relation to revenues at about 40%. Production expense includes both operation and maintenance costs of production facilities. Approximately 80% of these costs are comprised of fuel costs for generation and purchased power—most of which is passed through the fuel clause adjustment.

Beyond the revenue / expense relationship are other important factors

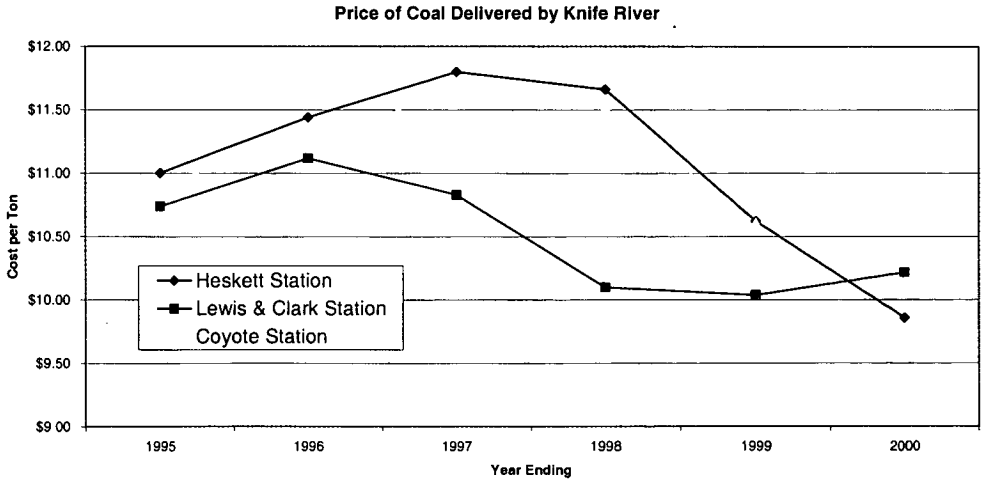
worth considering before agreeing to the Company's production expense level. For example, the Commission should look at MDU's track record with regard to managing its per unit production costs, use of generation facilities and line loss. Beginning with MDU's per unit cost of production, the following chart depicts per unit costs for each of MDU's primary sources of power.



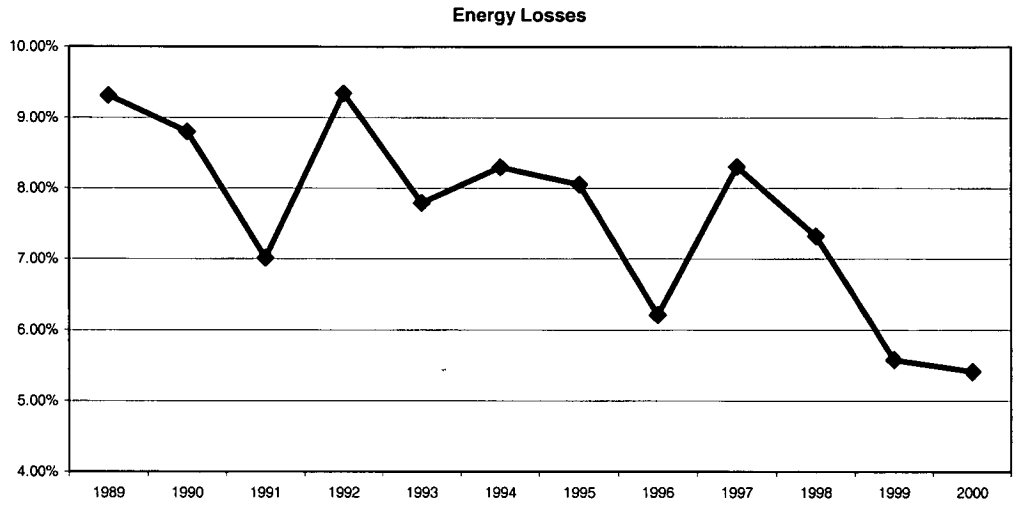
As you can see from the above chart, purchased power costs have increased dramatically during the past few years. This can be expected as available supplies become more and more restricted. Yet, MDU has managed to keep its overall costs down around 2¢ per kWh as shown by the red line. MDU has been able to accomplish this through reductions in per unit costs of its own generation facilities. A number of factors have contributed to this including higher utilization of existing plant as shown in the following chart.



In addition to higher utilization of existing plant, MDU's coal prices from its affiliate Knife River Corporation have been reduced substantially in recent years. On September 28, 2000 MDU Resources Group, Inc announced an agreement to sell its coal operations. According to information provided by MDU, the following chart depicts average coal prices delivered from Knife River since 1995.



Further, production costs have remained stable in the face of rising purchased power costs by efforts of MDU to lower its line loss. The following chart depicts the line loss percentage experienced by MDU during recent years.



Transmission Expense

Q: DID STAFF MAKE ANY ADJUSTMENTS TO THE TRANSMISSION EXPENSE AS REPORTED IN MDU'S 2000 ANNUAL REPORT?

A: Transmission expense levels have been very stable in recent years and staff proposes no adjustments.

Distribution Expense

Q: DID STAFF MAKE ANY ADJUSTMENTS TO THE DISTRIBUTION EXPENSE AS REPORTED IN MDU'S 2000 ANNUAL REPORT?

A: In 1999, Distribution Expense increased by 12% and remained near that level in 2000. Per review of the FERC Form 1 for the total electric operations of MDU, the increase is primarily a result of increases in Miscellaneous Expense (Account 588) and Maintenance of Overhead Lines (Account 593). Miscellaneous Expense includes the cost of labor, materials used and expenses incurred in distribution system operations not provided for elsewhere. According to MDU, the increased costs are primarily attributable to increased labor costs. Staff does not take exception to MDU's increased distribution costs.

Customer Accounts Expense

Customer Service and Informational Expense

Sales Expense

Q: DID STAFF MAKE ANY ADJUSTMENTS TO THE ABOVE REFERENCED ACCOUNTS AS REPORTED IN MDU'S 2000 ANNUAL REPORT?

A: Staff did not make any adjustments to customer accounts expense, customer service and informational expense or sales expense. The expense levels in these accounts have remained fairly constant in recent years and no further review was deemed necessary.

Administrative and General Expenses

Q: DID STAFF MAKE ANY ADJUSTMENTS TO A & G EXPENSES AS REPORTED IN MDU'S 2000 ANNUAL REPORT?

A: Staff did not make any adjustments to these accounts. Again, the costs have remained relatively stable over the past few years and no adjustments are deemed necessary.

Depreciation Expense

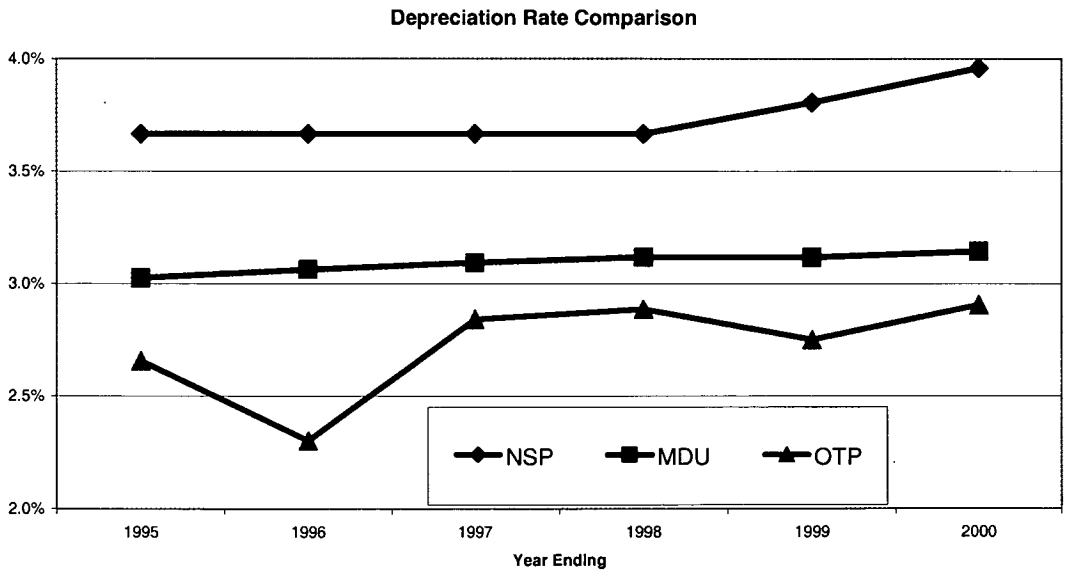
Q: WHAT DID STAFF CONCLUDE WITH REGARD TO MDU'S REPORTED DEPRECIATION EXPENSE FOR THE TEST YEAR?

A: Staff agrees that MDU's reported depreciation expense for 2000 is fair and reasonable for use in this proceeding. Such a determination was not reached through technical analysis but rather by broad analytical analysis to save time and money.

In MDU's last electric rate case before the Commission in 1986 (Case No. 10,799), the Commission rejected MDU's proposal to increase depreciation rates for steam generation facilities and ordered that the current rates remain in effect. The Commission's decision was based on a 1975 depreciation study. MDU later performed a depreciation study for all electric and gas plant based on 1991 plant balances. Based on that study, MDU began using new depreciation rates in 1994. The new rates resulted in an overall increase in depreciation rates but actually reduced the depreciation expense associated with steam generation plant by about $250,000 per year. In the end then, it seems the Commission made the right decision not to accelerate depreciation in the last rate case.

Staff reviewed the overall change in depreciation expense in relation to the change in plant in service balances and noted a slight increase in that relationship since 1994. However, the difference has not been material to this case.

Staff also compared MDU's overall rate of depreciation to the overall electric depreciation rates of Otter Tail Power Company and Northern States Power Company and found that MDU's rates remain in the middle. MDU's rates are higher than Otter Tail's and lower than NSP's. Given the comparable rates and the lack of fluctuations in cost, staff is not compelled to recommend any changes to the depreciation rates at this time. Following is a comparison of the overall depreciation rates for each of the electric utilities regulated by the Commission.



Taxes Other Than Income Tax Expense

Q: DID STAFF MAKE ANY ADJUSTMENTS TO TAXES OTHER THAN INCOME TAX EXPENSE AS REPORTED IN MDU'S 2000 ANNUAL REPORT?

A: No. This account primarily includes property taxes and the Company's share of social security taxes but includes other taxes like North Dakota coal conversion tax, franchise and gross revenue taxes etc. Again, expenses have remained relatively stable over recent years and no adjustment is necessary.

Income Tax Expense

Q: DID STAFF MAKE ANY ADJUSTMENTS TO INCOME TAX EXPENSE AS REORTED IN MDU'S 2000 ANNUAL REPORT?

A: Staff made no adjustments to income tax expense other than to reflect the impact of other adjustments supported by staff.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

Montana-Dakota Utilities Co.
Case No. PU-399-01-186
Sales for Resale Margin

Description	Jan	Feb	Mar	Apr	May	Jun	Jul
1996:							
Sales for Resale Kwh	43,099,000	47,089,000	68,998,000	34,198,000	9,584,000	30,410,000	25,890,000
Revenues	$669,023.20	$716,303.19	$1,075,131.85	$492,011.15	$138,431.30	$546,308.94	$463,977.06
Fuel Cost	480,821.55	498,168.27	755,686.76	378,555.23	103,463.94	357,594.02	306,504.48
Margin	$188,201.65	$218,134.92	$319,445.09	$113,455.92	$34,967.36	$188,714.92	$157,472.58
Margin %	28%	30%	30%	23%	25%	35%	34%
1997:							
Sales for Resale Kwh	33,549,000	47,962,884	33,383,000	1,802,000	9,395,000	34,576,000	33,514,000
Revenues	$668,282.30	$849,640.58	$571,568.00	$40,747.50	$148,874.00	$569,670.53	$864,975.65
Fuel Cost	452,226.96	520,395.09	375,298.60	27,941.99	106,474.16	416,782.28	571,802.82
Margin	$216,055.34	$329,245.49	$196,269.40	$12,805.51	$42,399.84	$152,888.25	$293,172.83
Margin %	32%	39%	34%	31%	28%	27%	34%
1998:							
Sales for Resale Kwh	40,758,000	41,158,000	47,459,000	69,442,000	53,699,000	57,016,000	50,459,000
Revenues	$713,798.50	$753,899.50	$835,337.85	$1,118,367.25	$1,200,783.70	$1,245,261.64	$1,209,635.88
Demand/Other Revenue						17,496.00	0.00
Fuel Cost	428,263.41	426,256.46	553,276.15	725,084.86	698,859.92	654,840.21	689,581.33
Margin	$285,535.09	$327,643.04	$282,061.70	$393,282.39	$501,923.78	$607,917.43	$520,054.55
Margin %	40%	43%	34%	35%	42%	48%	43%
1999:							
Sales for Resale Kwh	80,306,000	78,158,000	110,119,000	92,440,000	87,283,000	68,950,000	66,689,000
Revenues	$1,633,111.60	$1,535,893.15	$2,071,592.20	$1,831,965.50	$1,657,263.95	$1,817,207.05	$2,115,693.10
Demand/Other Revenue	0.00	0.00	0.00		45,000.00	45,000.00	45,000.00
Fuel Cost	968,070.94	874,967.67	1,150,293.92	1,018,736.75	952,531.21	1,025,787.84	1,209,373.13
Margin	$665,040.66	$660,925.48	$921,298.28	$813,228.75	$749,732.74	$836,419.21	$951,319.97
Margin %	41%	43%	44%	44%	44%	45%	44%

Schedule MRD-1

Montana-Dakota Utilities Co.
Case No. PU-399-01-186
Sales for Resale Margin

Description	Jan	Feb	Mar	Apr	May	Jun	Jul
2000:							
Sales for Resale Kwh	75,705,000	96,622,848	84,450,000	54,665,000	59,466,624	87,269,000	55,742,000
Revenues	$1,675,302.65	$1,906,357.25	$1,640,229.15	$996,686.00	$1,200,523.94	$2,477,281.45	$1,787,453.10
Demand/Other Revenue	0.00	0.00	0.00	0.00	0.00	240,000.00	120,000.00
Demand/Other Cost	0.00	0.00	0.00	0.00	0.00	106,666.66	53,333.33
Fuel Cost	1,204,391.86	1,086,355.37	919,542.09	618,452.00	605,941.62	1,305,411.80	1,262,405.51
Margin	$470,910.79	$820,001.88	$720,687.06	$378,234.00	$594,582.32	$1,305,202.99	$591,714.26
Margin %	28%	43%	44%	38%	50%	48%	31%
2001							
Sales for Resale Kwh	83,940,000	85,312,848	98,385,000	82,021,000	50,891,000		
Revenues	$2,336,055.40	$2,212,103.56	$2,678,562.15	$2,274,681.50	$1,345,245.30		
Demand/Other Revenue	33,333.33	33,333.33	33,333.33	33,333.35	0.00		
Demand/Other Cost	0.00	0.00	0.00	0.00	0.00		
Insurance Recovery	0.00	917,792.00	0.00	(179,467.60)	72,516.34		
Fuel Cost	1,020,048.17	966,638.30	1,113,920.59	938,822.67	885,792.84		
Margin	$1,349,340.56	$2,196,590.59	$1,597,974.89	$1,189,724.58	$531,968.80		
Margin %	57%	98%	59%	52%	40%		

Montana-Dakota Utilities
Case No. PU-399-01-186
Sales for Resale Margin

Description	Aug	Sep	Oct	Nov	Dec	Total
1996:						
Sales for Resale Kwh	18,244,000	12,013,826	4,500,638	31,737,616	48,771,000	374,535,080
Revenues	$342,243.97	$250,770.57	$89,503.70	$609,286.94	$860,539.11	$6,253,530.98
Fuel Cost	230,843.52	168,202.46	63,783.51	420,590.63	573,450.51	4,337,664.88
Margin	$111,400.45	$82,568.11	$25,720.19	$188,696.31	$287,088.60	$1,915,866.10
Margin %	33%	33%	29%	31%	33%	31%
1997:						
Sales for Resale Kwh	6,563,813	30,534,000	29,218,616	42,451,000	59,004,232	361,953,545
Revenues	$170,592.93	$524,535.25	$548,992.20	$920,598.35	$1,145,722.19	$7,024,199.48
Fuel Cost	112,046.72	375,590.25	380,486.83	521,839.07	671,321.66	4,532,206.43
Margin	$58,546.21	$148,945.00	$168,505.37	$398,759.28	$474,400.53	$2,491,993.05
Margin %	34%	28%	31%	43%	41%	35%
1998:						
Sales for Resale Kwh	35,733,080	26,003,616	21,977,000	66,180,000	76,655,000	586,539,696
Revenues	$840,454.76	$550,019.35	$438,990.60	$1,368,436.15	$1,584,417.00	$11,859,402.18
Demand/Other Revenue	0.00	0.00	0.00	0.00	0.00	17,496.00
Fuel Cost	530,818.86	360,616.30	266,743.59	857,315.18	868,514.38	7,060,170.65
Margin	$309,635.90	$189,403.05	$172,247.01	$511,120.97	$715,902.62	$4,816,727.53
Margin %	37%	34%	39%	37%	45%	41%
1999:						
Sales for Resale Kwh	61,202,616	59,340,000	72,200,000	83,644,000	83,189,000	943,520,616
Revenues	$1,820,146.61	$1,106,080.45	$1,172,225.00	$1,487,567.50	$1,457,582.90	$19,706,329.01
Demand/Other Revenue	45,000.00	45,000.00	45,000.00			270,000.00
Fuel Cost	882,060.82	642,217.38	678,264.81	933,575.15	867,600.46	11,203,480.08
Margin	$983,085.79	$508,863.07	$538,960.19	$553,992.35	$589,982.44	$8,772,848.93
Margin %	53%	44%	44%	37%	40%	44%

Montana-Dakota Utilities
Case No. PU-399-01-186
Sales for Resale Margin

Description	Aug	Sep	Oct	Nov	Dec	Total
2000:						
Sales for Resale Kwh	66,350,000	100,316,000	112,189,000	66,611,000	70,932,000	930,318,472
Revenues	$2,235,064.80	$2,100,033.20	$2,199,392.30	$1,793,521.60	$1,826,411.40	$21,838,256.84
Demand/Other Revenue	120,000.00	120,000.00	120,000.00	33,333.33	33,333.33	786,666.66
Demand/Other Cost	53,333.33	53,333.33	53,333.33	0.00	0.00	319,999.98
Fuel Cost	1,123,688.59	1,135,336.50	1,322,645.55	863,247.32	939,160.18	12,386,578.39
Margin	$1,178,042.88	$1,031,363.37	$943,413.42	$963,607.61	$920,584.55	$9,918,345.13
Margin %	50%	46%	41%	53%	50%	44%
2001						
Sales for Resale Kwh						400,549,848
Revenues						$10,846,647.91
Demand/Other Revenue						133,333.34
Demand/Other Cost						0.00
Insurance Recovery						
Fuel Cost						4,925,222.57
Margin						$6,054,758.68
Margin %						55%

Schedule MRD-1

BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Rates and Charges of MONTANA-DAKOTA UTILITIES CO. For Retail Electric Service in the State of North Dakota	))))	Case No. PU-399-01-186

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COMMISSION
EXECUTIVE SECRETARY

DIRECT TESTIMONY OF

CHARLES W. KING

On behalf of the Staff of the Public Service Commission
Rate of Return

August 31, 2001

EXHIBIT
4
2/25/02

14 PU-399-01-186 Pages: 96
Direct Testimony of Charles W King
by Public Service Commission
Exhibit # 4
09/07/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

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Figure 1

Attachment A.....Resume of Charles W. King

Attachment B.....Expert Witness Appearances of Charles W.King

Attachment C .....MDU Data Responses Referred to by Charles W. King

BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Rates and Charges of MONTANA-DAKOTA UTILITIES CO. For Retail Electric Service in the State of North Dakota	))))	Case No. PU-399-01-186

DIRECT TESTIMONY OF

CHARLES W. KING

On behalf of the Staff of the Public Service Commission
Rate of Return

August 31, 2001

DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 30-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to recommend the appropriate rate of return to be applied to the jurisdictional electric rate base of Montana-Dakota Utilities Company ("MDU" or "the Company") in North Dakota.

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN FOR THE COMPANY'S NORTH DAKOTA ELECTRIC OPERATIONS?

A. Based on the analyses presented in this testimony, I find that the appropriate rate of return on the Company's electric operations in North Dakota is **9.67 percent,** inclusive of a return to equity of **11.2 percent.**

Q. WHAT INFORMATION DID YOU OBTAIN FROM THE COMPANY IN PREPARING YOUR TESTIMONY?

A. I obtained the Company's last five annual reports to the Commission on its electric operations in the state of North Dakota. On the basis of these reports and the year 2000 Annual Report to Stockholders of MDU's parent, MDU Resources Group, Inc., I prepared 17 data requests, which the Company answered on July 2, 2001. These responses in turn prompted a further round of data requests which I submitted on July 19 and the Company answered on August 2, 2001. I submitted a single further data request on August 15, which the Company promptly answered on August 16, 2001. Throughout my testimony and exhibits, I shall refer to these data responses by their dates, July 2,

August 2 and August 16. Copies of all referenced data responses are included in Attachment C to this testimony.

Q. HOW WILL YOU STRUCTURE YOUR TESTIMONY?

A. I will first discuss the capital structure of the Company, that is, the mix of debt, preferred stock and common equity. I will next quantify the cost of the Company's debt and preferred stock. I will then discuss the theory of return to equity, the methodology for estimating it, and my development of the equity return requirement of MDU. I will conclude by applying the respective cost rates to the components of the capital structure to develop the appropriate return to total capital.

I. CAPITAL STRUCTURE

Q. WHAT WAS THE COMPANY'S CAPITAL STRUCTURE AT THE END OF YEAR 2000?

A. The reported capital structures of MDU and its parent, MDU Resources Group, Inc at the end of 2000 were as follows:

Table 1
Capital Structure, December 31, 2000
($000)

	M-D Utilities Co.		MDU Resources Group, Inc.	
Short-term Debt	$8,000	2.27%	$27,695	1.68%
Long-term Debt	173,950	49.32%	728,166	44.04%
Preferred Stock	16 ,500	4.68%	16,400	0.99%
Common Equity	154,200	43.73%	881,060	53.29%
Total	$352,650	100.00%	$1,653,321	100.00%

Sources: M-D Utilities Co. 2000 Report for Electric Operations to the North Dakota; P.S.C.; MDU Resources, Inc. 2000 Annual Report to Stockholders.

Q. WHICH OF THESE CAPITAL STRUCTURES DOES THE COMPANY USE IN MEASURING ITS RETURN?

A. Neither. It uses the capital structure of M-D Utilities Co. exclusive of short-term debt. The Company justifies the exclusion of short-term debt on the grounds that it finances its capital-intensive utility operations exclusively with long-term debt.[1]

Q. IS IT APPROPRIATE TO EXCLUDE SHORT-TERM DEBT, AS THE COMPANY HAS DONE?

A. The answer to this question depends upon the contents of the rate base upon which the return is being calculated or to which the return will be applied. If that rate base consisted solely of capital investments in plant and equipment, then the Company may have a point. These long-term investments are indeed financed with long-term debt and equity. However, the Company's rate base also consists of materials and supplies inventories, fuel stocks, and prepayments. These short-term capital commitments will be financed in part with short-term debt. For this reason, I believe it is appropriate to include short-term debt in the capital structure. In this particular case, the effect is relatively small anyway, because neither M-D Utilities nor MDU Resources is carrying a large amount of short-term debt.

Q. WHICH CAPITAL STRUCTURE, M-D UTILITIES OR MDU RESOURCES, SHOULD BE USED IN CALCULATING THE RETURN TO CAPITAL FOR MDU'S INVESTMENT IN NORTH DAKOTA ELECTRIC OPERATIONS?

A. A case can be made either way. On the one hand, M-D Utilities' capital structure is not necessarily driven by the need to optimize the mix of financial resources. While the parent company is prevented by M-D Utilities' bond indenture from taking on excessive debt, nothing prevents if from inflating the equity percentage so as to "game" the regulatory system into granting a relatively high composite return and tax allowance.

[1] July 2 Response to Q. 7.

On the other hand, the parent company's capital structure is likely to be unnecessarily conservative, that is, too equity rich, for a regulated electric utility operation. That is because, as I will demonstrate later in this testimony, the overwhelming majority of the Company's operations are in competitive, non-regulated lines of business. These activities incur much greater business risk than do the utility operations, and this risk must be offset by reducing the financial risk associated with large amounts of debt.

Looking at the ratios in Table 1, there is no evidence whatever that the Company has assigned excessive equity to M-D Utilities. To the contrary, the capital structures adhere to the relationship one would expect given the different mixes of business risk. M-D Utilities, the less risky enterprise, has a more levered, that is, more debt-rich, capital structure than does the parent company, with its greater involvement in non-regulated, competitive activities.

For this reason, I believe it appropriate to base the capital structure used for finding an appropriate composite return to MDU's North Dakota electric operations on the mix of financing sources of M-D Utilities Co.

Q. DO YOU THEREFORE ADOPT THE CAPITAL STRUCTURE SHOWN IN THE COLUMN UNDER "M-D UTILITIES CO." IN TABLE 1 ABOVE?

A. No. That capital structure is a "snapshot" of the Company's capital mix as of December 31, 2000. The capital structure used to find a composite return on rate base should reflect the on-going financing of the Company's operations during the coming years.

Q. WHAT ADJUSTMENTS NEED TO BE MADE TO REFLECT THE ON-GOING FINANCING OF THE COMPANY'S OPERATIONS DURING THE COMING YEARS?

A. First, the amount of short-term debt should reflect a broader average than just the amount outstanding on December 31, 2000. I do not have any estimate of the average amount of this debt during the year, but the Company's FERC Form 1 indicates that the beginning of the year amount of short-term debt was $13 million. I have averaged this amount with the end-of-year amount of $8 million to arrive at an estimate of $10.5 million as an expression of the average requirement for short-term debt.

The makeup of the remaining debt as proposed by the Company is set forth in its July 2 response to question 2. That response shows $40 million in a term loan from the Bank of America. This is a line of credit against which MDU can draw to meet its short-term financing requirements. The $40 million was borrowed on December 29, 2000 and matured on January 2, 2001[2] – clearly not an expression of a continuing requirement. The Company indicates that the average amount outstanding against this line of credit during 2000 was $1.3 million.[3] I have substituted this amount for the $40 million.

The other adjustment I have made is to the Grant County 6.2% Pollution Control bond. This bond is being paid off over the coming three years.[4] I have reduced the amount outstanding to reflect the average level of indebtedness during the years 2001 through 2003. This results in a reduction of this outstanding debt from $2.6 million to $2.0 million.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND?

A. The detail of the capital structure that I recommend is presented in Schedule 1 to my exhibit. It can be summarized as follows:

[2] August 2 response to Q. 19..
[3] August 2 response to Q. 15.

Table 2
M-D Utilities Co. Capital Structure

Item	Amount	Proportion
Debt	$144,893,971	45.90%
Preferred Stock	16,500,000	5.23%
Common Equity	154,250,010	48.87%
Total	$315,643,981	100.00%

II. THE COST OF DEBT AND PREFERRED STOCK

Q. HAS THE COMPANY PROVIDED A CALCULATION OF ITS CLAIMED COST OF DEBT?

A. Yes. The Company's calculation of its claimed cost of debt was provided on July 2 in response to question no. 2. Further detail was provided on August 2 in response to question no. 9. The Company calculates a composite cost of debt, inclusive of $40 million in the Bank of America term loan, as 9.388 percent.

Q. HOW DID THE COMPANY CALCULATE ITS DEBT COST?

A. The Company subtracted the underwriters' commissions, loss on reacquisition, and issuance expense from each debt issue. It then calculated the effective cost based on the payments of interest and principal to maturity relative to these net proceeds. The relationship of these payments to the net proceeds is asserted by the Company to be its cost of debt.

Q. IS THIS THE APPROPRIATE CALCULATION?

A. No. Attachment B to the Company's August 2 response to question no. 10 is the FERC rules on the treatment of premium, discount, expense, and gain or loss on reacquisition of long-term debt. It states that the premium, discount or expense of a debt issue should be

[4] August 2 response to Q. 9, page 9.

amortized over the life of the issue. Losses (or gains) on reacquisition of debt should be amortized over the remainder of the original life of the issue retired. The process of reducing the initial amount of the proceeds is thus inconsistent with FERC practice. Instead, these costs should be amortized as an expense.

Q. HAVE YOU PROVIDED THE CORRECT CALCULATION?

A. Yes. Schedule 2 presents the correct calculation of debt cost. I have subtracted only underwriters' commissions in calculating the net proceeds. I have included as an expense the average 2001-2003 amortization of discounts, expenses and redemption losses as reported by the Company in its August 16 response to question no. 1. These expenses are added to the interest costs. As the tabulation shows, the composite cost of debt, inclusive of short -term debt, is 8.62 percent.

Q. WHAT IS THE COST OF THE PREFERRED STOCK PORTION OF THE COMPANY'S CAPITAL STRUCTURE?

A. The Company reports that the cost rate for its $16.5 million in preferred stock is 4.632 percent. I have accepted this value for purposes of calculating the Company's overall rate of return.

III. THE COST OF EQUITY

Q. WHAT IS THE BASIS FOR FINDING A RATE OR RETURN TO THE EQUITY COMPONENT OF THE CAPITAL DEVOTED TO MDU'S ELECTRIC UTILITY OPERATIONS IN NORTH DAKOTA?

A. In its landmark Hope Natural Gas decision, the United States Supreme Court established the following standards for the return to equity that must be allowed a regulated public utility:

> ..the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[5]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return to equity. The first is the "comparable earnings" standard, that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that they must be sufficient to assure "confidence in the financial integrity of the enterprise," and the third is that they must allow the utility to be able to attract capital.

Q. HOW CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. There is a certain circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to all enterprises having corresponding risks are comparable with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings in comparison with the present and prospective earnings of all other stocks and other investments available to them. If the earnings of a firm are depressed, then investors will pay only a low price for that firm's stock. As a result, their return on the market value of that stock will be comparable to the return on the market value of the stock of other highly profitable companies which, as a consequence of their profitability, have been bid up to a very high price. Thus, if "return" is defined as the earnings of an equity investment relative to its current market price, then the comparable earnings test becomes a cipher. All returns are comparable with all other returns.

In public utility regulation the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That

[5]Federal Power Commission et. al. vs. Hope Natural Gas Company, 320 U.S. 592, at 603.

return is combined with the cost of debt and preferred stock, using either the actual or a hypothetical minimum-cost capital structure. The blended return to total capital is then applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings which regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. If the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to shun such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. IN SEEKING "ENTERPRISES OF COMPARABLE RISK," WHAT IS THE RELEVANT "RISK" FOR PURPOSES OF THIS INQUIRY?

A. The purpose of this inquiry is to find the cost of the equity capital of MDU that is devoted to providing regulated retail electric service in North Dakota. The relevant risk is therefore that associated with providing regulated retail electric service.

This level of risk is <u>not</u> the same risk as that of MDU Resources Group, Inc., the corporation that provides the electric service at issue in this inquiry. That is because regulated utility service is a relatively small proportion of the total revenue and earnings of the parent corporation, and regulated electric service is an even smaller proportion, as demonstrated in Table 3:

Table 3
MDU Resources Group, Inc.
(Dollars in Millions)

Business Segment	Revenues		Operating Income	
Electric Retail	$161.6	8.6%	$38.8	17.9%
Natural Gas Distribution	233.1	12.4%	9.5	4.4%
Total Regulated	$394.7	21.0%	$48.3	22.3%
Utility Services	169.4		16.6	
Pipeline and Energy Services	636.8		28.8	
Natural Gas and Oil Production	138.3		66.5	
Construction Materials and Mining	631.4		56.8	
Intersegment eliminations	(96.9)			
Total Company	$1,873.7	100.0%	$217.0	100.0%

Source: MDU Resources Group, Inc. 2000 Annual Report to Stockholders, page 1.
Note: numbers may not add due to rounding.

Q. FOR PURPOSES OF THIS INQUIRY, WHAT TYPES OF ENTERPRISES HAVE COMPARABLE RISK TO MDU'S REGULATED RETAIL ELECTRIC SERVICE?

A. The enterprises likely to have business risks most comparable to MDU's retail electric service are those engaged in the same business, that is, the generation, transmission and distribution of electricity to retail customers under rate base/rate-of-return regulation. This criterion excludes a number of utilities that have sold their electric generation assets.

Since we are attempting to find a rate of return sufficient to maintain credit and attract capital, we cannot examine utilities that have poor credit ratings. Accordingly, I have established as a criterion for acceptability that the company must have an "investment grade" bond rating, which is defined as BBB or better from Standard & Poors and Baa or better from Moody's. Finally, the company must be of broadly comparable size, meaning that must be a large corporation. I have established a criterion of $100 million or more in gross revenues.

Q. HAVE YOU IDENTIFIED SPECIFIC COMPANIES THAT YOU BELIEVE COMPARABLE TO MDU'S REGULATED ELECTRIC SERVICE?

Yes. Schedule 3 shows the companies engaged in regulated electric generation, transmission and distribution services that are listed by Moody's and Standard & Poors as having investment grade bonds and total operating revenues in excess of $100 million. There are two lists. Page 1 presents companies engaged in regulated electric service only and that are still vertically integrated, that is, that still generate the power they distribute to their retail customers. Page 2 lists companies that provide both regulated electric and gas distribution service. As I shall demonstrate later in this testimony, there appears to be a difference in the perceived level of risk associated with these two categories of utilities.

One of the central difficulties of this inquiry is that the procedures for identifying the cost of equity capital require that we be able to analyze the market prices of traded stocks. This means that we must deal with stand-alone corporations whose stock is traded on public markets. We cannot look at subsidiaries, affiliates, divisions or sectors of larger companies.

For this inquiry, we must therefore find companies whose market risk is driven by the earnings, both present and prospective, from providing regulated utility services, including retail electric service. If the risk driver is some other business, the company cannot be said to be comparable.

Schedule 3 shows the revenues generated from regulated services and their proportion to total revenues. In the majority of cases, the regulated proportion of revenues is so low, and the unregulated proportion so high, that the perceived risk of the company has to be influenced heavily by its non-regulated activities. This is particularly relevant because in most cases, the non-regulated activities are fastest growing segments of the company, and they essentially drive investors' expectations as to future growth and profitability.

For this reason, I have adopted as a criterion of comparability that at least 85 percent of the company's revenues must be generated by regulated activities: electric service revenues for the utilities listed on page 1 and both electric and gas revenues for the

companies on page 2. This criterion yields a list of five electric-only utilities and nine combination electric/gas utilities, as follows:

Electric Only	Electric and Gas
Empire District Electric Co.	Alliant Energy
FPL Group	Ameren
Kansas City Power & Light	Consolidated Edison, Inc.
Pinnacle West	DPL, Inc.
Southern Company	Energy East
	Madison Gas & Electric
	Progress Energy
	Puget Sound Energy
	Sierra Pacific

Q. HOW WILL YOU IDENTIFY THE MARKET-DETERMINED RATE OF RETURN TO THE EQUITY CAPITAL INVESTMENT IN MDU'S NORTH DAKOTA ELECTRIC OPERATIONS?

A. I shall first apply the Discounted Cash Flow ("DCF") procedure, which I consider to be the most accurate test of a market return. I shall then consider the interest rate risk premium approach as a "sanity check" on my DCF results.

A. DISCOUNTED CASH FLOW PROCEDURE

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW PROCEDURE.

A. The basic premise of the Discounted Cash Flow (" DCF") procedure is that the market values each stock at the discounted present value of all future flows of cash that investors expect from purchasing that stock. The discount rate that equates those future cash flows with the market value of the stock is the investors' required rate of return.

The DCF approach is usually represented by the following formula:

$$k = {}^{d}/_{P} + g$$

where k = required rate of return
d = dividend in the immediate period
P = market price

g = expected growth rate in dividends

While the DCF method is usually presented in mathematical notation format (as above), it can also be described in narrative fashion. The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price.

Q. DON'T MOST INVESTORS REGARD CAPITAL APPRECIATION AS A PORTION OF THEIR EXPECTED RETURN?

A. Yes. The expectation of capital appreciation is captured in the "g" or growth portion of the DCF formula. If dividends grow, then it follows that the market price of the stock will grow as well. It is this growth that most equity investors seek, at least in part, in purchasing shares in a traded company.

Q. IS THERE A CONVENTIONAL PROCEDURE FOR CALCULATING DCF RETURNS?

A. Yes. There is a conventional procedure for calculating equity return under the DCF formula that is often referred to as the "classic" DCF calculation. The Federal Communications Commission ("FCC") recently concluded that this method should be given the greatest weight in determining the rate of return to equity.[6] I agree with this conclusion.

[6] *Notice Initiating a Prescription Proceeding and Notice of Proposed Rulemaking,* CC Docket No. 98-166, October 5, 1998.

Q. HOW IS THE "g" OR GROWTH FACTOR IN THE DCF FORMULA IDENTIFIED UNDER THE CLASSIC DCF CALCULATION?

A According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and they do not necessarily reflect the underlying driver of earnings. Simply by changing the dividend payout ratio, a company's management can create a rate of dividend growth that is unsustainable. For this reason, I believe that earnings per share ("EPS") is the most reliable indicator of the "g" factor.

The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast future earnings of traded companies. No one forecast can be considered reliable, but presumably a consensus of forecasts might be a good indication of investors' collective expectations as regards the company's future prospects.

I am aware of two sources for "consensus" estimates of investment analysts' predictions. One is the Institutional Brokers Estimate Sytem ("I/B/E/S"). The other is a somewhat broader survey of investment analysts by Zacks Investment Research, Inc., which includes retail as well as institutional brokers.

Q. WHAT ARE THE CONSENSUS ESTIMATES OF EPS GROWTH FOR THE COMPARABLE COMPANIES THAT YOU HAVE IDENTIFIED?

A. The Zacks' five year consensus growth estimates are as follows:

Table 4
Zacks Five Year Consensus EPS Forecasts

Electric-only Utilities		Combination Electric and Gas	
Empire District Electric	n.a.	Alliant Energy	2.0%
FPL Group	7.1%	Ameren	4.7%
Kansas City Power & Light	6.0%	Consolidated Edison	4.0%
Pinnacle West	9.0%	DPL	9.7%
Southern Company	5.8%	Energy East	6.5%
		Madison Gas & Electric	n.a.
		Progress Energy	7.1%
		Puget Sound Energy	5.3%
		Sierra Pacific	4.0%

n.a.: There have been no investment analysts' reports on these companies.

Q. HOW DOES THE CLASSIC DCF CALCULATION DERIVE THE DIVIDEND YIELD PORTION OF THE DCF FORMULA?

A. Under the classic calculation, the dividend yield is calculated as the next year's dividend divided by a recent average of the price of the stock. The resultant yield should reasonably match the dividend yields shown by the financial reporting services.

There are several ways to predict next year's dividend. Several investors' services provide forecasts of dividends. Another, somewhat more mechanical approach is to compute the next year's dividend as the most recent dividend annualized and then increased by one half of the analysts' prediction of long-term annual growth rate in earnings per share.

Q. WHAT ARE THE NEXT YEAR'S DIVIDENDS FOR THE COMPARISON COMPANIES YOU HAVE IDENTIFIED?

A. Using the mechanical approach, I calculate the following dividends for the comparison companies.

Table 5
Next Period Dividends

Electric Utilities				Electric and Gas Utilities			
	Current Dividend (1)	½ Grth Rate	Next Pd. Div.		Current Dividend (1)	½ Grth Rate	Next Pd. Div.
Empire District Electric	$1.28	n.a.	n.a.	Alliant Energy	$2.00	1.0%	$2.02
FPL Group	$2.24	3.65%	$2.32	Ameren	$2.54	2.35%	$2.60
Kansas City P & L	$1.66	3.0%	$1.71	Consolidated Edison	$2.20	2.0%	$2.24
Pinnacle West	$1.50	4.5%	$1.57	DPL	$0.94	4.85%	$0.99
Southern Company	$1.34	2.9%	$1.38	Energy East	$0.92	3.25%	$0.95
				Madison Gas & Electric	$1.32	n.a.	n.a.
				Progress Energy	$2.12	3.55%	$2.20
				Puget Sound Energy	$1.84	2.66%	$1.89
				Sierra Pacific	$1.00	2.0%	$1.02

(1) Zacks Company Reports

Q. HOW IS THE DENOMINATOR IN THE DIVIDEND YIELD CALCULATION, THE RECENT PRICE OF THE STOCKS, IDENTIFIED?

A. Some judgement is required to establish a set of price observations that capture the investing public's current perception of value, while at the same time reflecting some stability in the market. Given the fluctuations of the markets, a price observation for a single day, week, or even month runs the risk of becoming obsolete in a very short time. Market fluctuations also mean that the use of monthly highs and lows may exaggerate the effect of some of the sharp drops and rises that the markets have experienced recently. For this reason, I believe it is best to use the average of prices over a period somewhat longer than a month. Since CBS MarketWatch routinely publishes the average of the 50 most recent trading day closing prices, I have chosen this series as the price basis for the calculation of dividend yield.

Q. WHAT IS THE DIVIDEND YIELD OF YOUR COMPARISON COMPANIES?

A. Using the foregoing dividends and the MarketWatch price averages, I calculate the dividend yields as follows:

Table 6
Next Period Dividend Yields

Electric Utilities				Electric and Gas Utilities			
	Dividend	50-Day Price	Dividend Yield		Dividend	50-Day Price	Dividend Yield
Empire District Electric	n.a.	n.a.	n.a	Alliant Energy	$2.02	$29.16	6.9%
FPL Group	$2.32	$56.76	4.1%	Ameren	$2.60	$40.80	6.4%
Kansas City P & L	$1.71	$24.82	6.9%	Consolidated Edison	$2.24	$40.12	5.6%
Pinnacle West	$1.57	$44.90	3.4%	DPL	$0.99	$26.43	3.7%
Southern Company	$1.38	$23.26	5.9%	Energy East	$0.95	$20.77	4.6%
				Madison Gas & Electric	n.a.	$24.76	
				Progress Energy	$2.20	$42.83	5.1%
				Puget Sound Energy	$1.89	$24.99	7.6%
				Sierra Pacific	$1.02	$16.04	6.4%

Note: 50 day prices prior to August 28, 2001. Source: CBS MarketWatch.

Q. WHAT ARE THE RESULTS FOR THE "CLASSIC" DCF FORMULATION?

A. The "classic" formulation of the DCF procedure is the sum the growth rates identified in Table 4 with the dividend yields in Table 6, as follows:

Table 7
"Classic" DCF Results

Electric Utilities				Electric and Gas Utilities			
	5 Year Growth Rate	Dividend Yield	DCF Return		5 Year Growth Rate	Dividend Yield	DCF Return
Empire District Electric	n.a.	n.a	n.a.	Alliant Energy	2.0%	6.9%	8.9%
FPL Group	7.1%	4.1%	11.2%	Ameren	4.7%	6.4%	11.1%
Kansas City P & L	6.0%	6.9%	12.9%	Consolidated Edison	4.0%	5.6%	9.6%
Pinnacle West	9.0%	3.4%	12.4%	DPL	9.7%	3.7%	13.4%
Southern Company	5.8%	5.9%	11.7%	Energy East	6.5%	4.6%	11.1%
				Madison Gas & Electric	n.a.	n.a.	n.a.
				Progress Energy	7.1%	5.1%	12.2%
				Puget Sound Energy	5.3%	7.6%	12.9%
				Sierra Pacific	4.0%	6.4%	10.4%
Average			**12.0%**				**11.2%**

Q. ARE THERE ALTERNATIVE FORMULATIONS OF THE DCF PROCEDURE?

A. Yes. There are broadly two alternative formulations to the DCF procedure that have been used in utility rate of return studies, both reflecting different ways of estimating the "g" or growth factor. The first is based on the proposition that growth in earnings and dividends for a regulated public utility is constrained by the growth in book value per share. This is because public utility regulation has traditionally authorized earnings in relation to a "rate base" reflective of the book value of the investment devoted to utility service. The rate of growth in per-share book value is a function of (1) the earnings retention ratio, (2) the authorized rate of return and (3) dilution or accretion from sales of new stock.

The other alternative uses historical trends in growth in earnings and dividends to calculate the "g" factor in the DCF formula.

Q. WHAT IS YOUR ASSESSMENT OF THE EARNINGS GROWTH MODEL FOR THE COMPARABLE COMPANIES YOU HAVE IDENTIFIED?

A. The book value growth model is no longer suitable for most electric utilities for two reasons. Although I have limited my selection of comparable utilities to those having over 85 percent of their revenues subject to regulation, with the single exception of Madison Gas & Electric, all of these companies still have some unregulated activities for which the book value growth model does not apply.

Possibly more relevant is the fact that very few utilities are so closely regulated that the only source of book value growth is earnings retained within the limit of an authorized rate of return. Since the late 1980s, when the electric utility industry generally began experiencing declining costs, there have been relatively few rate cases. MDU is a good example. It has not had an electric rate case in North Dakota since 1987,[7] or an electric

[7] Case No. 10,799, decided January 27, 1987, See July 2 response to Q. 13.

rate case in any state since 1993.[8] During the interval since those cases, MDU may have been able to enjoy returns above what regulation might have established as the authorized rate of return. If so, then its "g" factor would be greater than would be indicated by the earnings growth model.

Q. WHAT IS THE RELEVANCE OF HISTORICAL GROWTH TRENDS FOR THE COMPARABLE COMPANIES YOU HAVE IDENTIFIED?

A. Historical trends in dividends and earnings are relevant to an estimation of the "g" factor only to the extent that investors regard them as indicators of their future expectations. Most financial reports display considerable historical data, including past earnings per share and dividends, which suggests that this information is of interest to investors and analysts. The weight that they give to the trends in these indicators is, of course, unknown and unknowable.

Q. CAN YOU IDENTIFY THE HISTORICAL GROWTH TRENDS OF THE COMPARABLE COMPANIES?

A. The record of earnings growth over the past five years for the comparable companies is as follows:

Table 8
Five Year Historical EPS Growth

Electric-only Utilities		Combination Electric and Gas	
Empire District Electric	1.1%	Alliant Energy	1.6%
FPL Group	6.9%	Ameren	3.0%
Kansas City Power & Light	-0.7%	Consolidated Edison	1.2%
Pinnacle West	10.0%	DPL	6.5%
Southern Company	4.4%	Energy East	7.2%
		Madison Gas & Electric	6.7%
		Progress Energy	3.0%
		Puget Sound Energy	2.8%
		Sierra Pacific	-180.6%

[8] August 2 response to Q. 20.

Q. WHAT IS YOUR ASSESSMENT OF THE USE OF HISTORICAL EARNINGS GROWTH AS AN INDICATOR OF THE "g" FACTOR IN THE DCF FORMULA?

A. A comparison of the historical record of earnings growth in Table 8 with the Zacks' investment analysts' consensus future growth in Table 4 suggests that historical data, to the extent it is considered, is not the principal driver of investor expectations of the future. Certainly that appears to be the case for the two utilities with negative historical growth. In other cases, the history of strong past growth may reinforce the expectation of future growth, but in all cases, the "g" factor is better represented by the surveys of analysts' EPS predictions.

Q. CAN YOU EXPLAIN THE VARIATION AMONG THE "CLASSIC" DCF RESULTS SHOWN IN TABLE 7?

A. To a great extent the variation among the "classic" DCF results shown in Table 7 can be explained by differences in capital structure. All other things being equal, the riskiness of a stock varies inversely with the proportion of total capital that consists of equity investment. The greater the proportion of equity, the less the risk that variations in earnings might tip the company into insolvency. Conversely, the lower the equity ratio, the greater the danger that the company might not be able to pay the interest on its debt or the fixed premiums on its preferred stock, leaving common shareholders with no earnings and no dividends. A comparison of the DCF results for the comparison companies with the common equity ratios, inclusive and exclusive of short term debt, is as follows:

Table 9
"Classic" DCF Results and Common Equity Ratios

Electric Utilities				Electric and Gas Utilities			
	DCF Return	Equity No short-term debt	Equity with short-term debt		DCF Return	Equity No short-term debt	Equity with short-term debt
Empire District Electric	n.a.	42.4%	37.7%.	Alliant Energy	8.9%	50.2%	44.7%
FPL Group	11.2%	57.1%	51.1%	Ameren	11.1%	51.8%	50.1%
Kansas City P & L	12.9%	46.0%	44.8%	Consolidated Edison	9.6%	49.1%	48.0%
Pinnacle West	12.4%	54.9%	53.9%	DPL	13.4%	27.7%	27.7%
Southern Company	11.7%	48.0%	45.1%	Energy East	11.1%	41.8%	37.9%
				Madison Gas & Electric	n.a.	52.2%	46.8%
				Progress Energy	12.2%	47.5%	35.3%
				Puget Sound Energy	12.9%	37.4%	34.0%
				Sierra Pacific	10.4%	36.0%	34.1%

The four electric-only utilities are fairly closely grouped both as to equity ratios and DCF return indications. However, even within this group, the utility with the lowest equity ratio, Kansas City P&L, has the highest DCF return, and the utility with the highest equity ratio (excluding short-term debt), FPL, has the lowest DCF return.

Among the combination electric/gas utilities, the very low equity ratios of DPL and Puget Sound certainly help explain their relatively high DCF return requirements. Similarly, two of the three companies with DCF returns below 11 percent have equity ratios 45 percent or higher. Sierra Pacific remains an anomaly, with equity ratios in the 34-36 percent range and a DCF return of only 10.4 percent. However, the fact that this company, alone among those in the tabulation, provides not only electric and gas, but also water service may help explain investors' perception of low business risk. So, too, might its position as an electric generator in the generation-short California-Nevada market.

Q. HOW DOES MDU FIT INTO THIS PICTURE?

A. MDU is a combination gas and electric utility. As shown on Table 7, these combination utilities appear to have lower return requirements than electric-only companies. This is not an accident. As a heating source, electricity and gas are to great extent competitors. When a company offers only electric service, it likely faces the competition of a gas utility and the consequent uncertainties as to market penetration. But when it offers both gas and electricity, it has a reasonable guarantee that regardless of changes in heating technology or consumer preference, it will control the most of the market for heating fuels. Its business risk is therefore lower. For this reason, the most comparable group of utilities to MDU is the combination electric and gas companies.

As regards financial risk, MDU's equity ratio is 50.8 percent without short-term debt and 48.9 percent with short term debt. See Schedule 1. These percentages are higher than all but one (Ameren) of the combination companies for which DCF results are shown on Table 9, suggesting a very low level of risk.

In this regard, M-D Utilities may be helped by the very conservative capital structure of its parent, MDU Resources. Schedule 4 shows the capital structures of all of the combination gas and electric utilities fitting the criteria of investment grade bond ratings, retention of generating facilities, and revenues in excess of $100 million. MDU Resources has a higher equity ratio than any of these companies. Its financial risk is therefore among the lowest. This condition undoubtedly contributes to a lower equity return for both the parent and the subsidiary.

Q. WHAT RATE OF RETURN DO YOU RECOMMEND FOR MDU?

A. In light of low level of both business and financial risk of MDU's electric service, I believe a good case could be made for setting its rate of return to equity at the very bottom end of the range of returns indicated in my DCF analysis of comparable companies. However, the rate of return set in this proceeding is likely to remain in effect for a number of years. I therefore believe it unadvisable to lock the company into a relatively low return for an extended period during which business conditions and the

company's outlook might change. For this reason, I recommend that the rate of return for MDU's electric operations be set at the average DCF return for combination electric and gas utilities, or **11.2 percent.**

B. INTEREST RATE RISK PREMIUM CHECK

Q. IS THERE A WAY TO CHECK THE REASONABLENESS OF YOUR DCF FINDING?

A. Yes. While equity return requirements are difficult to estimate, bond yields and interest rates can be measured with precision and currency. Indeed, they are reported daily in business publications and weekly by the Federal Reserve Board.

The relationship between bond yields and equity return requirements has been a subject of considerable controversy among rate-of-return analysts. There is a body of theory which holds that over enough time, the record of the historically realized differences between bond yields and common stock returns is a good measure of the risk premium that investors require from stocks relative to bonds.[9] I do not subscribe to this theory, but I do acknowledge that there is a relationship between measurable interest rates and bond yields and immeasurable equity returns.

The reason for this relationship is that fixed income investments – bonds and preferred stock – compete with common stock for investors' dollars. If interest rates fall, then (all other things being equal) investors have an increased incentive to commit their funds to the stock market. As more funds flow into stocks, their prices increase, reducing the return available from current and forecast profits. Conversely, if interest rates increase, then stock prices fall, and the return to the newly repriced equity market increases.

[9] "Stocks, Bonds, Bills and Inflation: The Past and the Future," by Roger G. Ibbotson and Rex. A. Sinquefield, The Financial Analysts Research Foundation, University of Virginia.

To be sure, the return requirements of the two forms of investment do not move in lock step. Bonds suffer inflation risk, while stocks are considered a hedge against inflation. Conversely, stocks are far more susceptible to the effects of the business cycle than bonds, so when recession threatens, the spread between bond yields and required stock returns is likely to increase. Nonetheless, over time, a decline in bond yields should signal a corresponding (although not directly correlated) decline in equity return requirements.

For this reason, its is worthwhile to examine the trend in bond yields and interest rates over the time since the last equity return prescriptions for MDU to determine whether a finding of 11.2 percent is reasonable. If it appears that bond yields have increased, but I am recommending a reduced return to equity, then there may be reason to question my finding. On the other hand, if my proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of my finding.

Q. WHAT IS THE RELATIONSHIP BETWEEN EQUITY RETURN ALLOWANCES AND BOND YIELDS OVER THE YEARS?

Figure 1 provides this comparison. It shows the average annual yields to 10-year Treasury bonds and Moody's Aaa Corporate bonds from 1986 through 2000 and to July 2001. It also shows the last electric equity return finding for MDU in North Dakota in 1987 and the three other equity return rulings by other state commission since then. The chart shows that bond yields are now at their lowest level in 15 years, significantly below their position when each of the previous return findings were made.

The specific the relationship between the equity return findings and the then-current bond yields is as follows:

Table 10
MDU Equity Return Allowances and Contemporaneous Bond Yields

Case	Date	Equity Return	10 Year Treasury	Aaa Corp. Bonds
ND Electric	January 1987	12.71%	7.08%	8.36%
MT Electric	March 1987	12.3%	7.25%	8.36%
SD Gas	December 1994	11.5%	7.81%	8.46%
MT Gas	May 1996	12.0%	6.74%	7.62%
ND Electric	August 2001[10]	11.2%	5.13%	7.07%

Source: MDU July 1 response to Q. 13 and August 2 response to Q. 20; Federal Reserve Statistical Releases.

Q. WHAT DO YOU CONCLUDE FROM THESE COMPARISONS?

A. I conclude that while my recommended equity return allowance is lower than any that have been approved for MDU in the past 15 years, this result is justified by the evidence of lower overall capital costs. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to the experience of the past 15 years. For this reason, I conclude that my recommended equity return of 11.2 percent is reasonable.

IV RETURN TO TOTAL CAPITAL

Q. WHAT IS YOUR RECOMMENDED RETURN TO TOTAL CAPITAL?

A. My recommended return to total capital is **9.67 percent**, calculated as follows:

Table 11
Return to Total Capital

Item	Proportion	Cost	Weighted Cost
Debt	45.90%	8.62%	3.96%
Preferred Stock	5.23%	4.632%	0.24%
Equity	48.87%	11.2%	5.47%
Total	100.00%		**9.67%**

[10] Bond yield data for the week ending August 3, 2001.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

Schedule 1

Montana-Dakota Utilities Co.
Capital Structure

Series	Source	Principal Amount	Proportion With Short-term Debt	Excluding Short-term Debt Amount	Excluding Short-term Debt Proportion
First Mortgage Bonds					
8.25% Due 4/1/07	July 2, #2, Att. 2-A	$30,000,000			
8.6% Due 4/1/12	"	35,000,000			
6.52% Due 10/1/04	"	15,000,000			
6.71% Due 10/01/09	"	15,000,000			
5.83% Due 10/1/08	"	15,000,000			
Mercer Co. 6.65%	"	15,000,000			
Richland Co. 6.65%	"	3,250,000			
Morton Co. 6.65%	"	2,600,000			
Grant County 6.2% (2001-2003)	", Aug 2, #9,Att.A, p9	2,000,000			
Long-Term Note Payable	July 2, Att 2-A	243,971			
Term Loan	July 2, Att 2-A; Aug 2, #15	1,300,000			
Other Short-term Debt	FERC Fm 1,p 112; Jul 2,#6	10,500,000			
Total Debt	Total Above Lines	$144,893,971	45.90%	$133,093,971	43.80%
Preferred Equity	July 2, Att. 1-A, p. 1	16,500,000	5.23%	16,500,000	5.43%
Common Equity	"	154,250,010	48.87%	154,250,010	50.77%
Total Capital		$315,643,981	100.00%	$303,843,981	100.00%

Schedule 2

Montana-Dakota Utilities Co.
Cost of Debt

Series	Source	A Principal Amount	B Underwriters Commission	C Net Proceeds	D Annual Interest & Amortization
First Mortgage Bonds					
8.25% Due 4/1/07	July 2, #2, Att. 2-A	$30,000,000	$225,000	$29,775,000	$2,475,000
8.6% Due 4/1/12	"	35,000,000	306,250	34,693,750	3,010,000
6.52% Due 10/1/04	"	15,000,000	90,000	14,910,000	978,000
6.71% Due 10/01/09	"	15,000,000	93,750	14,906,250	1,006,500
5.83% Due 10/1/08	"	15,000,000	93,750	14,906,250	874,500
Mercer Co. 6.65%	"	15,000,000	0	15,000,000	997,500
Richland Co. 6.65%	"	3,250,000	0	3,250,000	108,063
Morton Co. 6.65%	"	2,600,000	0	2,600,000	172,900
Grant County 6.2% (2001-2003)	", Aug 2, #9,Att.A, p9	2,000,000	30,000	1,970,000	138,100
2001-2003 Avg Amortization of Discount Expense	Aug 16 #1, Att A				4,445
2001-2003 Avg Amortization of Debt Expense	"				138,311
2001-2003 Avg Amortization of Redemption Loss	"				1,202,012
2001-2003 Amortization of Loss -944	Aug 2, #10, Att A				454,933
Long-Term Note Payable	July 2, Att 2-A	243,971			19,226
Term Loan	July 2, Att 2-A; Aug 2, #15	1,300,000		1,300,000	124,475
Other Short-term Debt	FERC Fm 1,p 112; Jul 2,#6	10,500,000		10,500,000	693,000
Total		$144,893,971	$838,750	$143,811,250	$12,396,965
Weighted Average Debt Cost					8.620%

Electric Only Utilities
Proportion of Revenue from Regulated Service

Company Name	Total Revenue	Revenue from Regulated Electricity	Percent Rev. from Regulated Electricity
American Electric Power Co.	13,694	10,827	79.1%
Black Hills Corp.	1,624	173	10.7%
Cleco Corp.	821	620	75.5%
Duke Energy	49,318	4,946	10.0%
Empire District Electric Co.	**260**	**259**	**99.6%**
FPL Group	**7,082**	**6,361**	**89.8%**
Hawaiian Electric Co. Inc.	1,719	1,277	74.3%
IDACORP (Idaho Power)	1,019	836	82.0%
Kansas City Power & Light	**1,116**	**1,064**	**95.3%**
Oklahoma Gas & Electric	3,299	1,454	44.1%
Pinnacle West	**3,690**	**3,480**	**94.3%**
Portland Gen. Electric Company (Enron)	2,253	1,044	46.3%
Southern Company	**10,066**	**9,860**	**98.0%**

Electric & Gas Utilitiies
Percent Regulated Revenue

Company Name	Total Revenue	Regulated Electric Revenue	Regulated Gas Revenue	Percent Regulated Revenue
Allegheny Energy	4,012	2,507	*	62.5%
Alliant Energy	**2,405**	**1,648**	**415**	**85.8%**
Ameren	**3,856**	**3,526**	**324**	**99.8%**
Cinergy Corp	8,421	2,692	429	37.1%
Consolidated Edison Inc.	**9,431**	**6,938**	**1,262**	**86.9%**
Constellation Energy Group	3,878	2,052	502	65.9%
DPL Inc (Dayton Power & Light)	**1,437**	**1,090**	**184**	**88.7%**
DTE Energy	5,597	4,129		73.8%
Dominion Resources (Va. Power)	9,260	4,492	1,374	63.3%
Energy East	**2,960**	**2,024**	**772**	**94.5%**
Entergy Corp	10,016	7,220	166	73.7%
Madison Gas & Electric	**324**	**203**	**121**	**100.0%**
NI Source	6,031	1,557	1,807	55.8%
NorthWestern Corp.	7,132	87	95	2.6%
PPL Electric Utilities Corp	5,683	3,167	*	55.7%
Progress Energy	**4,119**	**3,565**	**324**	**94.4%**
Puget Sound Energy	**3,442**	**2,772**	**612**	**98.3%**
Reliant Energy	29,339	5,494	*	18.7%
Rochester Gas & Electric	1,448	731	340	74.0%
SCANA Corp(Pub Ser of NC, SC Elect. & Gas)	3,433	1,344	998	68.2%
Sempra Energy	7,143	2,184	3,305	76.8%
Sierra Pacific	**2,334**	**2,219**	**101**	**99.4%**
TXU Corp	22,009	4,752	962	26.0%
TECO Energy (Tampa Electric Co.& Peoples G	2,295	1,354	314	72.7%
UGI Corp.(UGI Utilities)	1,762	78	359	24.8%
Utilicorp-	28,975	1,208	826	7.0%
Vectren Corp	1,649	336	819	70.0%
Wisconsin Electric Power (Wisconsin Energy)	3,355	2,557	*	76.2%
WPS	1,951	625	265	45.6%
Xcel Energy (No. States Power)	11,592	6,492	1,466	68.7%
MDU Resources Group	1,874	162	233	21.1%

*Electric and gas revenues not separately identified.

Electric & Gas Utilities
Capital Structure

Without Short-term Debt

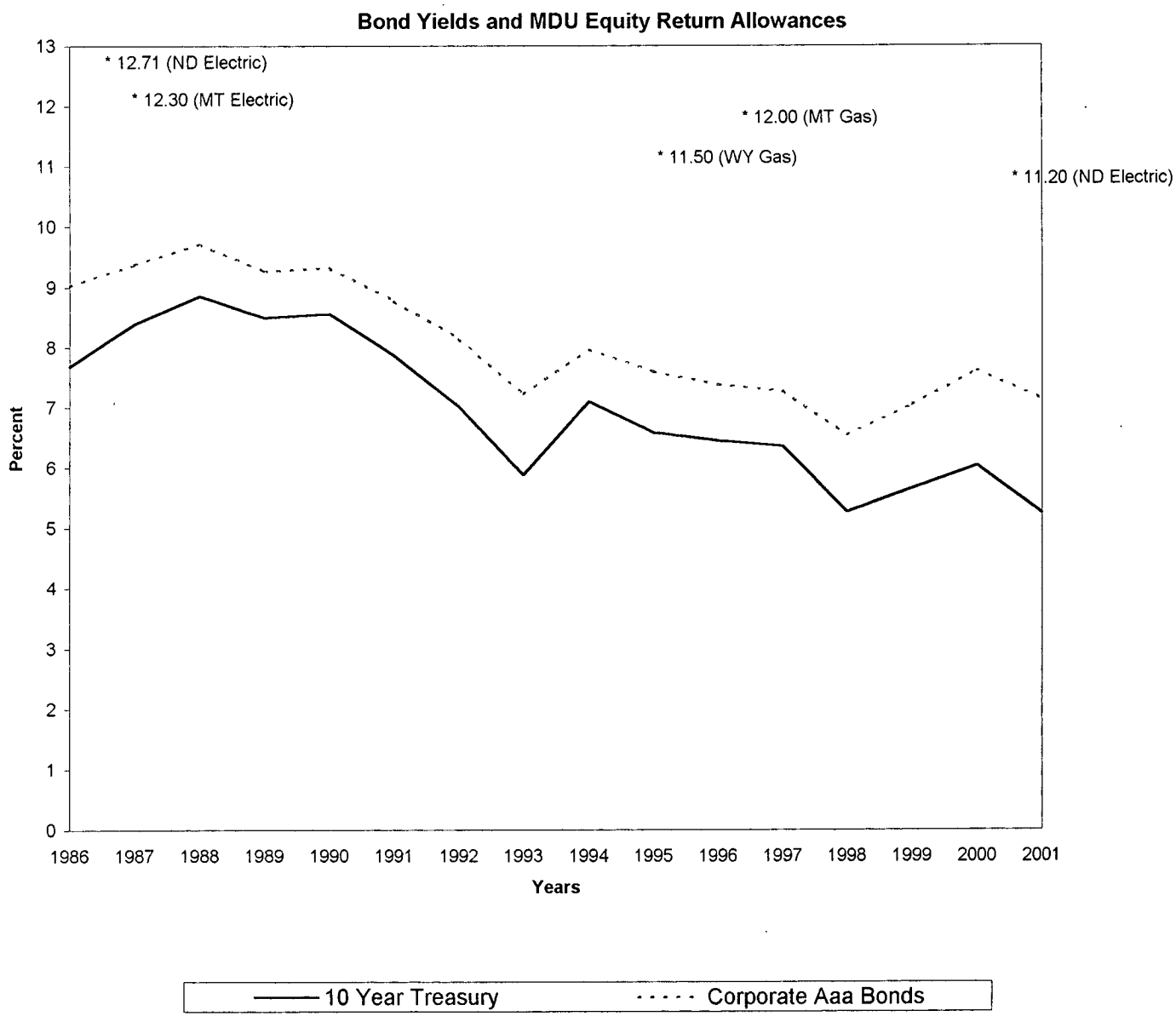
Company Name	(MILLIONS OF DOLLARS) Long-Term Debt	Preferred Stock	Other Pref'd Investment	Common Equity	Total Capital	Capital Structure Long-Term Debt	Preferred Stock	Other Pref'd Investment	Common Equity	Total Capital
Allegheny Energy	2,258	74		708	3,040	74.3%	2.4%		23.3%	100.0%
Alliant Energy	1,910	114		2,037	4,061	47.0%	2.8%		50.2%	100.0%
Ameren	2,745	235		3,197	6,177	44.4%	3.8%		51.8%	100.0%
Consolidated Edison Inc.	5,415	250		5,472	11,137	48.6%	2.2%		49.1%	100.0%
Constellation Energy Group	3,159	190		3,153	6,502	48.6%	2.9%		48.5%	100.0%
DPL Inc (Dayton Power & Light)	1,758	23	550	892	3,223	54.5%	0.7%	17.1%	27.7%	100.0%
DTE Energy	3,917			4,015	7,932	49.4%			50.6%	100.0%
Dominion Resources (Va. Power)	10,101	509		6,992	17,602	57.4%	2.9%		39.7%	100.0%
Energy East	2,347	43		1,717	4,107	57.1%	1.0%		41.8%	100.0%
Entergy Corp	7,732	400	215	7,338	15,685	49.3%	2.6%	1.4%	46.8%	100.0%
Madison Gas & Electric	183	0		200	383	47.8%	0.0%		52.2%	100.0%
NI Source	5,803	478		3,415	9,696	59.8%	4.9%		35.2%	100.0%
PPL Electric Utilities Corp	4,784	97		2,012	6,893	69.4%	1.4%		29.2%	100.0%
Progress Energy (Carolina Power & Light)	5,890	93		5424	11,407	51.6%	0.8%		47.5%	100.0%
Puget Sound Energy	2,171	118	100	1,427	3,816	56.9%	3.1%	2.6%	37.4%	100.0%
Reliant Energy	6,619		705	5,482	12,806	51.7%		5.5%	42.8%	100.0%
Rochester Gas & Electric	824	72		767	1,663	49.5%	4.3%		46.1%	100.0%
SCANA Corp(Pub Ser of NC, SC Elect. & Gas)	2,850	116	50	2,032	5,048	56.5%	2.3%	1.0%	40.3%	100.0%
Sempra Energy	3,268	204	200	2,494	6,166	53.0%	3.3%	3.2%	40.4%	100.0%
Sierra Pacific	2,134	50	237	1,360	3,781	56.4%	1.3%	6.3%	36.0%	100.0%
TECO Energy (Tampa Electric Co.& Peoples Gas)	1,375			1,560	2,935	46.8%			53.2%	100.0%
Vectren Corp	632	17		732	1,381	45.8%	1.2%		53.0%	100.0%
Wisconsin Electric Power (Wisconsin Energy)	2,733	30		2,017	4,780	57.2%	0.6%		42.2%	100.0%
Xcel Energy (No. States Power)	7,583	105		5,562	13,250	57.2%	0.8%		42.0%	100.0%
Average						53.8%	1.9%	1.5%	42.8%	100.0%
MDU Resources	728	16		881	1,625	44.8%	1.0%		54.2%	100.0%

Electric & Gas Utilities
Capital Structure

With Short-Term Debt

Company Name	(MILLIONS OF DOLLARS) Long-Term Debt	Short-Term Debt	Preferred Stock	Other Pref'd Investment	Common Equity	Total Capital	Capital Structure Long-Term Debt	Short-Term Debt	Preferred Stock	Other Pref'd Investment	Common Equity	Total Capital
Allegheny Energy	2,258	299	74		708	3,339	67.6%	9.0%	2.2%		21.2%	100.0%
Alliant Energy	1,910	500	114		2,037	4,561	41.9%	11.0%	2.5%		44.7%	100.0%
Ameren	2,745	203	235		3,197	6,380	43.0%	3.2%	3.7%		50.1%	100.0%
Consolidated Edison Inc.	5,415	255	250		5,472	11,392	47.5%	2.2%	2.2%		48.0%	100.0%
Constellation Energy Group	3,159	244	190		3,153	6,746	46.8%	3.6%	2.8%		46.7%	100.0%
DPL Inc (Dayton Power & Light)	1,758		23	550	892	3,223	54.5%	0.0%	0.7%	17.1%	27.7%	100.0%
DTE Energy	3,917	503			4,015	8,435	46.4%	6.0%			47.6%	100.0%
Dominion Resources (Va. Power)	10,101	3237	509		6,992	20,839	48.5%	15.5%	2.4%		33.6%	100.0%
Energy East	2,347	419	43		1,717	4,526	51.9%	9.3%	1.0%		37.9%	100.0%
Entergy Corp	7,732	388	400	215	7,338	16,073	48.1%	2.4%	2.5%	1.3%	45.7%	100.0%
Madison Gas & Electric	183	44	0		200	427	42.9%	10.3%			46.8%	100.0%
NI Source	5,803	2497	478		3,415	12,193	47.6%	20.5%	3.9%		28.0%	100.0%
PPL Electric Utilities Corp	4,784	1037	97		2,012	7,930	60.3%	13.1%	1.2%		25.4%	100.0%
Progress Energy (Carolina Power & Light)	5,890	3,973	93		5424	15,380	38.3%	25.8%	0.6%		35.3%	100.0%
Puget Sound Energy	2,171	378	118	100	1,427	4,194	51.8%	9.0%	2.8%	2.4%	34.0%	100.0%
Reliant Energy	6,619	5,004		705	5,482	17,810	37.2%	28.1%	0.0%	4.0%	30.8%	100.0%
Rochester Gas & Electric	824	122	72		767	1,785	46.2%	6.8%	4.0%		43.0%	100.0%
SCANA Corp(Pub Ser of NC, SC Elect. & Gas)	2,850	398	116	50	2,032	5,446	52.3%	7.3%	2.1%	0.9%	37.3%	100.0%
Sempra Energy	3,268	568	204	200	2,494	6,734	48.5%	8.4%	3.0%	3.0%	37.0%	100.0%
Sierra Pacific	2,134	213	50	237	1,360	3,994	53.4%	5.3%	1.3%	5.9%	34.1%	100.0%
TECO Energy (Tampa Electric Co.& Peoples G	1,375	1,209			1,560	4,144	33.2%	29.2%			37.6%	100.0%
Vectren Corp	632	760	17		732	2,141	29.5%	35.5%	0.8%		34.2%	100.0%
Wisconsin Electric Power (Wisconsin Energy)	2,733	1,386	30		2,017	6,166	44.3%	22.5%	0.5%		32.7%	100.0%
Xcel Energy (No. States Power)	7,583	1,475	105		5,562	14,725	51.5%	10.0%	0.7%		37.8%	100.0%
Average							47.2%	12.3%	1.7%	1.4%	37.4%	100.0%
MDU Resources	728	28	16		881	1,653	44.0%	1.7%	1.0%		53.3%	100.0%

Figure 1


Bond Yields and MDU Equity Return Allowances
* 12.71 (ND Electric)
* 12.30 (MT Electric)
* 12.00 (MT Gas)
* 11.50 (WY Gas)
* 11.20 (ND Electric)
Percent
13
12
11
10
9
8
7
6
5
4
3
2
1
0
1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001
Years
10 Year Treasury
Corporate Aaa Bonds

ATTACHMENT A

RESUME OF CHARLES W. KING

Charles W. King

Experience

Snavely King Majoros O'Connor & Lee, Inc.
Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation. Mr. King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

ATTACHMENT B

EXPERT WITNESS APPEARANCES OF CHARLES W. KING

CHARLES W. KING
Snavely King Majoros O'Connor & Lee, Inc.
1220 L Street, N.W.
Suite 410
Washington, D.C. 20005
(202) 371-1111

Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission Arizona Retailers Association	U-1345-I U-1345-II	Arizona Public Service Co. Arizona Public Service Co.	December 16, 1980 January 15, 1981
CA	California Retailers Association California Retailers Association California Retailers Association California Retailers & California Manufacturers California Retailers Association	57666 57602 59351 59351 61138	Pacific Gas & Electric Co. Southern California Edison Pacific Gas & Electric Co. Southern California Edison Southern California Edison	March 6, 1978 April 25, 1978 June 12, 1981 May 20, 1982 May 28, 1982
CO	U. S. Department of Defense J.C. Penny Company U.S. Department of Defense U. S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense	I&S 1100 5693 I&S 1339 I&S 1540 C. Council C. Council C. Council C. Council	Colorado Springs (Elec) All Electric Utilities Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec)	June 14, 1977 March 8, 1978 October 18, 1979 February 9, 1982 September 30, 1984 June 6, 1985 May 19, 1986 June 30, 1987
CT	Retailers Merchants Association Division of Consumer Counsel Public Utilities Control Auto Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Coalition of Hotels, Alloys & Retailers Coalition of Hotels, Alloys & Retailers	72-0204 76-0604,5 78-0303 80-0403,4 81-0413 81-0602,4 82-0701 85-10-22 87-07-01	Various Electric Utilities CL&P and HELCO Bridgeport Hydraulic Co. CL&P and HELCO United Illuminating Company CL&P and HELCO CL&P CL&P CL&P	July 22, 1976 November 10, 1977 (none) August 11, 1980 July 20, 1981 October 5, 1981 September 28, 1982 (none) April 25, 1988

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
DE	DPSC Staff	94-164	Artesian Water Company	(none)
	DPSC Staff	94-149	Wilmington Surburban Water Company	March 10, 1995
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
IL	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0698	Commonwealth Edison	June 22, 1977
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	76-0568	All Eletric Utilities	(none)
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	80-0546	Commonwealth Edison	March 5, 1981
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	82-0026	Commonwealth Edison	July 22, 1982
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	83-0537	Commonwealth Edison	March 19, 1984
	Illinois Retail Merchants Association/ Chicago Bldg. Mgrs. Association	87-0427	Commonwealth Edison	March/April 22, 1988
	Illinois Retail Merchants Association/	90-0169	Commonwealth Edison	October 29, 1990
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penny Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MD	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
NJ	Dept. of Public Advocate	761-8	Public Service Electric & Gas	January 18, 1977
	Dept. of Public Advocate	7911-951	Atlantic City Electric Co.	April 21, 1980
	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989
NY	N.Y. Council of Retail Merchants	26806	All Electric Utilities	February 3, 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa. Transp. Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn. Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn. Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
UT	Div. Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
VA	Consumer Congress of Virginia Consumer Congress of Virginia Va. Business Committee on Energy Virginia Pipe Trades Council	19426 19960 PUE 7900012 PUE 8900051	Virginia Electric Power Company Virginia Electric Power Company Virginia Electric Power Company Old Dominion Electric Corp. &	July 1, 1975 September 19, 1978 February 25, 1981 October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
CA	Arizona Burglar & Fire Alarm Association	9981-E-151-80-64	Mountain State Telephone	(none)
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	Federal Executive Agencies	T-01051B-99-0150	US WEST	Filed July 26, Sept 8,2000
	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont.	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan. 18, Oct. 31 November 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985 October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac. Bell Tel. & GTE of CA.	January 23, 1989
	California Cellular Resellers	A.88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	1.87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	1.88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc.	1.88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U.S. Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U.S. Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U.S. Department of Defense	Appl.	Mountain Bell Telephone Company	September 18, 1986
	U.S. Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U.S. Department of Defense	I&S 891-O82T	U.S. West Communications	February 21, 1990
	U.S. Department of Defense	905-544T	U.S. West Communications	July 17, 1991
	U.S. Department of Defense	90A-665T	U.S. West Communications	October 23, 1991
	U.S. Department of Defense	92M-039T	U.S. West Communications	February 24-24, 1992
	U.S. Department of Defense	92S-229T	U.S. West Communications	July 30-31, 1992
	U.S. Department of Defense	90A-665T	U.S. West Communications	November 6, 1996
	AT&T	96S-331T	U.S. West Communications	April 17, 1997

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utlilty	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co	February 10,1998
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995; Nov. 15, 2000
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
ID	U.S. Department of Energy U.S. Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co. Mountain Bell Telephone Co.	May 16, 1983 March 6, 1984
IL	Illinois Aalarm Companies Attorney Generaal of Illinois GTE Sprint Communications Co. Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr. Repr. 166.856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co. AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co. U.S. Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co.	August 5, 1983 (none)
MO	GTE Sprint Communications Co. Federal Executive Agencies Federal Executive Agencies	TR83-253 TC-89-14 TO-89-56	Southwestern Bell Tel. Co. Southwestern Bell Tel. Co. Southwestern Bell Tel. Co.	September 5, 1983 (none) November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990

State	Telecommunications Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utility	
NJ	Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate	Depr.Repr. 815-458 Depr.Repr. Depr.Repr. T092030358	N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company	Mar-79 October 15, 1981 March 1, 1982 February 1, 1985 September 30, 1992
NM	New Mexico Corporation Commission New Mexico Corporation Commission	1032 86-151-TC	Mountain Bell Telephone Co. General Telephone of Southwest	November 14, 1983 February 5, 1987
NV	Prime Cable of Las Vegas Prime Cable of Las Vegas	95-8034/8035 96-9035	Central Telephone - NV Sprint/Centel, Nevada Bell	Filed November 22, 1995 June 2, 1997
NY	Holmes Protection, Inc. Holmes Protection, Inc. 5 Alarm Companies GTE Sprint Communications Co.	27350 27469 27710 28425	New York Telephone Company New York Telephone Company New York Telephone Company All Telephone Companies	October 17, 1978 May 17, 1979 July 24, 1980 July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate	Depr.Repr. 86-511-C 86-541-C Depr.Repr. 89-180-C	Southern Bell Southern Bell General Telephone of South Southern Bell ALLTEL of South Carolina	July 1, 1986 December 11, 1986 April 8, 1987 July 10, 1989 September 26, 1989
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utlilty	
VI	V.I. Department of Commerce V.I. Public Service Commission	205 341	Virgin Islands Telephone Co. Virgin Islands Telephone Co.	April 29, 1980 March 20, 1991
WA	U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER WA Attorney General/TRACER	U-72-39 U-87-796-T U-88-20524 U-89-2698-F UT-940641 UT-941464 UT-951425 UT-961632	Pacific Northwest Bell Pacific Northwest Bell Pacific Northwest Bell US West Communications US West Communications US West Communications US West Communications US West Communications GTE Northwest, Inc	1973 December 20, 1983 November 8, 1988 November 28, 1989 Filed October 14, 1994 June 22, 1995 January 22, 1996 Filed June 23, 1997 July 29, 1997
WI	GTE Sprint	6720-TR-38	All Telephone Companies	October 20, 1983

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeornautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

CHARLES W. KING
Appearances before Federal Regulatory Agencies

U.S. Congress			
Client	**Docket**	**Subject**	**Date of Cross-Examination**
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	Jul-79
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			

ATTACHMENT C
MDU DATA RESPONSES REFERRED TO
IN THE TESTIMONY AND EXHIBIT OF CHARLES W. KING

July 2 Responses

No. 1

No. 2

No. 6

No. 7

No. 13

August 2 Responses

No. 9

No. 10

No. 15

No. 19

No. 20

August 16 Responses

No. 1

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JUNE 18, 2001
CASE NO. PU-399-01-186

The following questions relate to the page titled "Capital Structure" in the Company's Electric Operations Annual Report to the North Dakota P.S.C.

Request No. 1:

Please provide the complete balance sheet from which these data were drawn. Identify fully the corporate entity to which this balance sheet applies.

Response:

Please see Attachment A. The balance sheet shown is for MDU Resources Group, Inc., reporting on behalf of its division, Montana-Dakota Utilities Co.

MONTANA-DA[illegible]TA UTILITIES CO.
ACTUAL CAPITAL STRUCTURE
12/31/2000

ITEM	BALANCE	SUBSIDIARY PORTION OF BALANCE	ADJUSTED BALANCE	CAPITAL RATIO	COST	REQUIRED RETURN
LONG TERM DEBT	$173,893,971		$173,893,971	50.456%	9.388%	4.737%
PREFERRED STOCK	16,500,000		16,500,000	4.788%	4.632%	0.222%
COMMON EQUITY	884,686,278	730,436,178	154,250,100	44.756%		
TOTAL	$1,075,080,249	$730,436,178	$344,644,071	100.000%		

Response No. 1
Attachment 1-A
Page 1 of 4

MONTANA-DAKOTA UTILITIES
UTILITY COMMON EQUITY
12/31/2000

DESCRIPTION		AMOUNT	
TOTAL COMMON EQUITY - DECEMBER 31, 2000		$884,686,278	
LESS:			
UNAPPROPRIATED RETAINED EARNINGS OF SUBSIDIARIES	257,307,989		
STOCK INVESTMENT IN SUBSIDIARIES	60,814,000		
CAPITAL INVESTMENT IN SUBSIDIARIES	412,314,189		
SUBTOTAL		730,436,178	1/
UTILITY COMMON EQUITY - DECEMBER 31, 2000		154,250,100	

1/ - AGREES TO AMOUNT RECORDED IN INVESTMENT IN SUBSIDIARY ACCOUNT

Name of Respondent	This Report Is:	Date eport (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2000	Dec. 31, 2000

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	755,059,994	811,860,363
3	Construction Work in Progress (107)	200-201	7,367,551	4,386,767
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		762,427,545	816,247,130
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	414,008,994	447,997,314
6	Net Utility Plant (Enter Total of line 4 less 5)		348,418,551	368,249,816
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		348,418,551	368,249,816
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		4,459,358	1,195,374
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	161,779	133,220
15	(Less) Accum. Prov. for Depr. and Amort. (122)		14,883	25,123
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	538,839,875	730,436,178
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		27,885,507	24,559,856
21	Special Funds (125-128)		0	0
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		566,872,278	755,104,131
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		3,453,935	7,072,666
	Special Deposits (132-134)		1,100	1,200
26	Working Fund (135)		14,515	16,029
27	Temporary Cash Investments (136)		5,000,000	0
28	Notes Receivable (141)		0	0
29	Customer Accounts Receivable (142)		25,223,733	47,495,868
30	Other Accounts Receivable (143)		2,610,933	4,258,848
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		189,276	554,752
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		9,152,754	11,279,658
34	Fuel Stock (151)	227	2,051,748	1,746,988
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	5,924,248	6,288,886
38	Merchandise (155)	227	722,174	960,692
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	0	0
44	Gas Stored Underground - Current (164.1)		10,010,285	5,895,908
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		7,827,961	7,533,214
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		9,938	10,811
49	Rents Receivable (172)		0	0
	Accrued Utility Revenues (173)		16,040,758	40,145,126
	Miscellaneous Current and Accrued Assets (174)		671,844	224,057
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		88,526,650	132,375,199

Name of Respondent	This Report Is:	Date o port (Mo, Da, Yr)	Year of Report
MDU Resources Group, Inc.	(1) ☒ An Original (2) ☐ A Resubmission	12/31/2000	Dec. 31, 2000

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)	
1	**PROPRIETARY CAPITAL**				
2	Common Stock Issued (201)	250-251	57,277,915	65,267,567	(3)
3	Preferred Stock Issued (204)	250-251	16,600,000	16,500,000	(2)
4	Capital Stock Subscribed (202, 205)	252	0	0	
5	Stock Liability for Conversion (203, 206)	252	0	0	
6	Premium on Capital Stock (207)	252	375,006,302	521,464,938	(3)
7	Other Paid-In Capital (208-211)	253	0	0	
8	Installments Received on Capital Stock (212)	252	0	0	
9	(Less) Discount on Capital Stock (213)	254	0	0	
10	(Less) Capital Stock Expense (214)	254	2,694,284	2,694,284	(3)
11	Retained Earnings (215, 215.1, 216)	118-119	39,400,577	43,340,068	(3)
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	204,168,760	257,307,989	(3)
13	(Less) Reaquired Capital Stock (217)	250-251	0	0	
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		689,759,270	901,186,278	
15	**LONG-TERM DEBT**				
16	Bonds (221)	256-257	130,850,000	130,850,000	(1)
17	(Less) Reaquired Bonds (222)	256-257	0	0	
18	Advances from Associated Companies (223)	256-257	0	0	
19	Other Long-Term Debt (224)	256-257	43,100,000	43,043,971	(1)
20	Unamortized Premium on Long-Term Debt (225)		0	0	
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		54,451	50,006	
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		173,895,549	173,843,965	
23	**OTHER NONCURRENT LIABILITIES**				
24	Obligations Under Capital Leases - Noncurrent (227)		0	0	
	Accumulated Provision for Property Insurance (228.1)		0	0	
26	Accumulated Provision for Injuries and Damages (228.2)		1,257,993	1,195,672	
27	Accumulated Provision for Pensions and Benefits (228.3)		15,204,891	16,950,167	
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	0	
29	Accumulated Provision for Rate Refunds (229)		31,640	0	
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		16,494,524	18,145,839	
31	**CURRENT AND ACCRUED LIABILITIES**				
32	Notes Payable (231)		13,000,000	8,000,000	
33	Accounts Payable (232)		14,280,166	34,769,716	
34	Notes Payable to Associated Companies (233)		0	0	
35	Accounts Payable to Associated Companies (234)		5,143,024	6,047,863	
36	Customer Deposits (235)		1,089,989	1,200,063	
37	Taxes Accrued (236)	262-263	9,727,596	16,297,690	
38	Interest Accrued (237)		2,284,323	2,319,289	
39	Dividends Declared (238)		12,170,988	14,422,621	
40	Matured Long-Term Debt (239)		0	0	
41	Matured Interest (240)		0	0	
42	Tax Collections Payable (241)		863,483	2,062,760	
43	Miscellaneous Current and Accrued Liabilities (242)		6,898,665	8,101,718	
44	Obligations Under Capital Leases-Current (243)		0	0	
45	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		65,458,234	93,221,720	

Σ(1) L-T Debt 173,893,971
(2) Pref. Stock 16,500,000
Σ(3) Common equity 884,686,278

Response No. 1
Attachment 1-A
Page 4 of 4

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JUNE 18, 2001
CASE NO. PU-399-01-186

The following questions relate to the page titled "Capital Structure" in the Company's Electric Operations Annual Report to the North Dakota P.S.C.

Request No. 2:

Please provide a complete breakdown of the debt issues that make up the long-term debt in line 1. Show the amount of each issue, its effective cost to the Company, the maturity provisions and whether it is variable or fixed rate.

Response:

Please see Attachment A.

MONTANA-DAKOTA UTILITIES CO.
CAPITAL STRUCTURE - LONG-TERM DEBT
12/31/2000

LONG-TERM DEBT	BALANCE OUTSTANDING	ANNUAL COST		ADJUSTED EMBEDDED COST
SERIAL BONDS:				
BALANCE AT 12-31-00	$130,850,000	$11,743,442	1]	8.975%
AMORTIZATION OF LOSS ON BOND REDEMPTION-944		548,429	2]	
POLLUTION CONTROL BONDS				
BALANCE AT 12-31-00	2,800,000	183,568	1]	6.556%
TERM LOAN				
BALANCE AT 12-31-00	40,000,000	3,830,000	3]	9.575%
LONG TERM NOTE PAYABLE				
BALANCE AT 12-31-00	243,971	19,226	4]	7.880%
TOTAL LONG TERM DEBT	**$173,893,971**	**$16,324,665**		**9.388%**

1] Page 2.
2] Page 3.
3] Page 4.
4] Page 5.

Response No. 2
Attachment 2-A
Page 1 of 5

MONTANA-DAKOTA UTILITIES CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2000

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commissio Amount	Underwriters' Commissio % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
First Mortgage Bonds:									
Secured Medium-term Notes, Series A:									
8.25%	04/01/92	04/01/07	8.250%	$30,000,000	$30,000,000	$225,000	0.750%	$3,663,204	12.211%
8.6%	04/01/92	04/01/12	8.600%	35,000,000	34,911,100	306,250	0.877%	5,698,318	16.322%
6.52%	09/30/97	10/01/04	6.520%	15,000,000	15,000,000	90,000	0.600%	827,077	5.514%
6.71%	09/30/97	10/01/09	6.710%	15,000,000	15,000,000	93,750	0.625%	1,417,846	9.452%
5.83%	09/18/98	10/01/08	5.830%	15,000,000	15,000,000	93,750	0.625%	92,336	0.616%
Pollution Control Refunding Revenue Bonds:									
Mercer County 6.65%	06/01/92	06/01/22	6.650%	15,000,000	15,000,000	0	0.000%	938,724	6.258%
Richland County 6.65%	06/01/92	06/01/22	6.650%	3,250,000	3,250,000	0	0.000%	186,323	5.733%
Morton County 6.65%	06/01/92	06/01/22	6.650%	2,600,000	2,600,000	0	0.000%	179,014	6.885%
Pollution Control Notes:									
Grant County 6.2%	03/01/74	03/01/04	6.200%	5,600,000	5,600,000	84,000	1.500%	88,958	1.589%
				$136,450,000	$136,361,100	$892,750		$13,091,800	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
First Mortgage Bonds:						
Secured Medium-term Notes, Series A:						
8.25%	$26,111,796	87.039%	10.177%	$30,000,000	$3,053,100	
8.6%	28,906,532	82.590%	11.020%	35,000,000	3,857,000	
6.52%	14,082,923	93.886%	7.811%	15,000,000	1,171,650	
6.71%	13,488,404	89.923%	8.195%	15,000,000	1,229,250	
5.83%	14,813,914	98.759%	6.086%	15,000,000	912,900	
Pollution Control Refunding Revenue Bonds:						
Mercer County 6.65%	14,061,276	93.742%	7.288%	15,000,000	1,093,200	
Richland County 6.65%	3,063,677	94.267%	7.243%	3,250,000	235,398	
Morton County 6.65%	2,420,986	93.115%	7.344%	2,600,000	190,944	
Total First Mortgage Bonds	116,949,508			130,850,000	11,743,442	8.975%
Pollution Control Notes:						
Grant County 6.2%	5,427,042	96.911%	6.556%	2,800,000	183,568	6.556%
Total Long-Term Debt Capital	$122,376,550			$133,650,000	$11,927,010	8.924%

1/ Yield to maturity based upon the life, net proceeds, semiannual compounding of stated interest rate, and amortization of indenture revision costs.

Response No. 2
Attachment 2-A
Page 2 of 5

MONTANA-DAKOTA UTILITIES CO.
CAPITAL STRUCTURE
12/31/2000

ACCT #			12 MONTH AMORTIZATION
1890-UNAMORTIZED LOSS			
9 1/8% due 05-15-06	1/01 - 12/01	$20m redeemed 6/1/98 $5m redeemed 11/17/97 (sinker) $25m redeemed 6/1/96	548,429.21
NET AMOUNT			**548,429.21**

Bank of America

Response No. 2
Attachment 2-A
Page 4 of 5

:7127
Customer Number: 00111796
Commitment Number: 0000206811
Obligation Number: 001257514

Date: 3/21/01

Invoice Number: 0012572063

Please remit payment to:

Bill From: 12/31/00 To: 3/31/01

BANK OF AMERICA
IN ACCORDANCE WITH THE TERMS
OF YOUR AGREEMENT

Currency: USD

CUSTOMER TO REMIT

Service Unit: ASD003

Total Due: $ 20,821.92

PLEASE DETACH AND RETURN TOP PORTION WITH PAYMENT BY: 04/02/01

MDU RESOURCES GROUP INC

Invoice Date: 3/21/01

OBL #	FROM DATE	TO DATE	DESCRIPTION/BALANCE	RATE	ACTIVITY
001257514	Maturity	12/31/02			
	12/31/00	1/01/01	40,000,000.00	9.500000 /365	10,410.96 ✓
	1/01/01	1/02/01	40,000,000.00	9.500000 /365	10,410.96 ✓
			Obligation Total		20,821.92 ✓

Term loan also has

0.075 Commitment fee
Regardless of amount
out standing

9.5
+ 0.075
9.575

CURRENT PRINCIPAL DUE	.00
CURRENT INTEREST DUE	20,821.92
PAST DUE PRINCIPAL	.00
PAST DUE INTEREST	.00
INTEREST ADJUSTMENT	.00
TOTAL LATE FEES DUE	.00
TOTAL DUE	20,821.92
DUE DATE	4/02/01

A late fee may be assessed in accordance with the terms of your note if full payment is not made promptly.

Approved
Amt wired 4-2-01
[signature]
3-30-01

Great Plains Term loan - Long Term Note Pg-3=C

Monthly Payment Amt: 2,274.29
Interest Rate: 8.00%
Mortgage Amt: 247,146.59

Pymt Mth	Mthly Pymt	Beg. Mort. Amount	Ending Mort. Amount	Mthly Int Pd	Mthly Prin Pd	Total Prin Pd	Total Int Pd
0		7/1/00 →	247,146.59				
08/01/00	2,274.29	247,146.59	246,519.94	1,647.64	626.65	626.65	1,647.64
2	2,274.29	246,519.94	245,889.12	1,643.47	630.82	1,257.47	3,291.11
3	2,274.29	245,889.12	245,254.09	1,639.26	635.03	1,892.50	4,930.37
4	2,274.29	245,254.09	244,614.83	1,635.03	639.26	2,531.76	6,565.40
5	2,274.29	244,614.83	243,971.31	1,630.77	643.52	3,175.28	8,196.17
6	2,274.29	243,971.31	243,323.50	1,626.48	647.81	3,823.09	9,822.65
7	2,274.29	243,323.50	242,671.37	1,622.16	652.13	4,475.22	11,444.81
8	2,274.29	242,671.37	242,014.89	1,617.81	656.48	5,131.70	13,062.62
9	2,274.29	242,014.89	241,354.03	1,613.43	660.86	5,792.56	14,676.05
10	2,274.29	241,354.03	240,688.77	1,609.03	665.26	6,457.82	16,285.08
11	2,274.29	240,688.77	240,019.07	1,604.59	669.70	7,127.52	17,889.67
12	2,274.29	240,019.07	239,344.91	1,600.13	674.16	7,801.68	19,489.80
13	2,274.29	239,344.91	238,666.25	1,595.63	678.66	8,480.34	21,085.43
14	2,274.29	238,666.25	237,983.07	1,591.11	683.18	9,163.52	22,676.54
15	2,274.29	237,983.07	237,295.33	1,586.55	687.74	9,851.26	24,263.09
16	2,274.29	237,295.33	236,603.01	1,581.97	692.32	10,543.58	25,845.06
17	2,274.29	236,603.01	235,906.07	1,577.35	696.94	11,240.52	27,422.41
18	2,274.29	235,906.07	235,204.49	1,572.71	701.58	11,942.10	28,995.12
19	2,274.29	235,204.49	234,498.23	1,568.03	706.26	12,648.36	30,563.15
20	2,274.29	234,498.23	233,787.26	1,563.32	710.97	13,359.33	32,126.47
21	2,274.29	233,787.26	233,071.55	1,558.58	715.71	14,075.04	33,685.05
22	2,274.29	233,071.55	232,351.07	1,553.81	720.48	14,795.52	35,238.86
23	2,274.29	232,351.07	231,625.79	1,549.01	725.28	15,520.80	36,787.87
24	2,274.29	231,625.79	230,895.67	1,544.17	730.12	16,250.92	38,332.04
25	2,274.29	230,895.67	230,160.68	1,539.30	734.99	16,985.91	39,871.34
26	2,274.29	230,160.68	229,420.79	1,534.40	739.89	17,725.80	41,405.74
27	2,274.29	229,420.79	228,675.97	1,529.47	744.82	18,470.62	42,935.21
28	2,274.29	228,675.97	227,926.19	1,524.51	749.78	19,220.40	44,459.72
29	2,274.29	227,926.19	227,171.41	1,519.51	754.78	19,975.18	45,979.23
30	2,274.29	227,171.41	226,411.60	1,514.48	759.81	20,734.99	47,493.71
31	2,274.29	226,411.60	225,646.72	1,509.41	764.88	21,499.87	49,003.12
32	2,274.29	225,646.72	224,876.74	1,504.31	769.98	22,269.85	50,507.43
33	2,274.29	224,876.74	224,101.63	1,499.18	775.11	23,044.96	52,006.61
34	2,274.29	224,101.63	223,321.35	1,494.01	780.28	23,825.24	53,500.62
35	2,274.29	223,321.35	222,535.87	1,488.81	785.48	24,610.72	54,989.43
36	2,274.29	222,535.87	221,745.15	1,483.57	790.72	25,401.44	56,473.00
37	2,274.29	221,745.15	220,949.16	1,478.30	795.99	26,197.43	57,951.30
38	2,274.29	220,949.16	220,147.86	1,472.99	801.30	26,998.73	59,424.29
39	2,274.29	220,147.86	219,341.22	1,467.65	806.64	27,805.37	60,891.94
40	2,274.29	219,341.22	218,529.20	1,462.27	812.02	28,617.39	62,354.21
41	2,274.29	218,529.20	217,711.77	1,456.86	817.43	29,434.82	63,811.07
42	2,274.29	217,711.77	216,888.89	1,451.41	822.88	30,257.70	65,262.48
43	2,274.29	216,888.89	216,060.53	1,445.93	828.36	31,086.06	66,708.41

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JUNE 18, 2001
CASE NO. PU-399-01-186

The following questions relate to the page titled "Capital Structure" in the Company's Electric Operations Annual Report to the North Dakota P.S.C.

Request No. 6:

Show the components of short-term debt as of December 31, 2000 and the cost of each component.

Response:

Short-term borrowings at December 31, 2000 were $8.0 million consolidated. This debt was at Montana-Dakota Utilities Co., with an interest rate of 6.6 percent.

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JUNE 18, 2001
CASE NO. PU-399-01-186

The following questions relate to the page titled "Capital Structure" in the Company's Electric Operations Annual Report to the North Dakota P.S.C.

Request No. 7:

Explain fully and completely why short-term debt is not included in the capital structure.

Response:

Montana-Dakota excludes short-term debt from its capital structure as it finances its capital intensive utility operations with long-term debt.

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JUNE 18, 2001
CASE NO. PU-399-01-186

The following questions relate to the page titled "Capital Structure" in the Company's Electric Operations Annual Report to the North Dakota P.S.C.

Request No. 13:

What does the Company consider to be its currently authorized return to equity? When was that return authorized and in what Commission decision?

Response:

Montana-Dakota's currently authorized return on equity for its North Dakota electric operations is 12.71%, authorized in Case No. 10,799 in an Order issued January 27, 1987.

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JULY 19, 2001
CASE NO. PU-399-01-186

The following data requests relate to the responses provided Montana-Dakota Utilities ("MDU") under cover letter dated July 2, 2001.
With respect to Response No. 2, Attachment 2-A

Request No. 9:

Please provide the calculation of each of the percentages in the "Cost of Money" column on page 2. Describe the "semiannual compounding" and state the justification for it.

Response:

Please see Attachment A for the calculation of the Cost of Money percentages. The "Cost of Money" is derived from an IRR calculation utilizing the cash flow (yield to maturity) from the debt issuance over the life of the issue. A semiannual rate is calculated, then compounded for an annual effective rate or "Cost of Money". The compounding represents the cost of the semiannual interest payments to the bondholder.

2210-950

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
8.25% SECURED MEDIUM TERM NOTE

Last date of change: Apr-95

F:\FINRPT\CAPITAL\BONDS\[2210-950.xls]APR 1995

Principal amount of issue:	**$30,000,000**
Stated interest rate:	**8.250%**
Annual Interest Payment:	**$2,475,000**

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$1,237,500				4.064% SemiAnnual Rate
04-1-92 NET PROCEEDS	$26,111,796		$26,111,796	$30,000,000	
10-1-92	(1,237,500)		(1,237,500)	30,000,000	10.177% Annual Rate
04-1-93	(1,237,500)		(1,237,500)	30,000,000	
10-1-93	(1,237,500)		(1,237,500)	30,000,000	
04-1-94	(1,237,500)		(1,237,500)	30,000,000	
10-1-94	(1,237,500)		(1,237,500)	30,000,000	
04-1-95	(1,237,500)		(1,237,500)	30,000,000	
10-1-95	(1,237,500)		(1,237,500)	30,000,000	
04-1-96	(1,237,500)		(1,237,500)	30,000,000	
10-1-96	(1,237,500)		(1,237,500)	30,000,000	
04-1-97	(1,237,500)		(1,237,500)	30,000,000	
10-1-97	(1,237,500)		(1,237,500)	30,000,000	
04-1-98	(1,237,500)		(1,237,500)	30,000,000	
10-1-98	(1,237,500)		(1,237,500)	30,000,000	
04-1-99	(1,237,500)		(1,237,500)	30,000,000	
10-1-99	(1,237,500)		(1,237,500)	30,000,000	
04-1-00	(1,237,500)		(1,237,500)	30,000,000	
10-1-00	(1,237,500)		(1,237,500)	30,000,000	
04-1-01	(1,237,500)		(1,237,500)	30,000,000	
10-1-01	(1,237,500)		(1,237,500)	30,000,000	
04-1-02	(1,237,500)		(1,237,500)	30,000,000	
10-1-02	(1,237,500)		(1,237,500)	30,000,000	
04-1-03	(1,237,500)		(1,237,500)	30,000,000	
10-1-03	(1,237,500)		(1,237,500)	30,000,000	
04-1-04	(1,237,500)		(1,237,500)	30,000,000	
10-1-04	(1,237,500)		(1,237,500)	30,000,000	
04-1-05	(1,237,500)		(1,237,500)	30,000,000	
10-1-05	(1,237,500)		(1,237,500)	30,000,000	
04-1-06	(1,237,500)		(1,237,500)	30,000,000	
10-1-06	(1,237,500)		(1,237,500)	30,000,000	
1-07	(1,237,500)	(30,000,000)	(31,237,500)	0	

2210-951

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
8.6% SECURED MEDIUM TERM NOTE

ast date of change: Apr-95

F:\FINRPT\CAPITAL\BONDS\[2210-951.xls]APR 1995

Principal amount of issue:	$35,000,000
Stated interest rate:	8.600%
Annual Interest Payment:	$3,010,000

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate	
	$1,505,000				4.366%	SemiAnnual Rate
04-1-92 NET PROCEEDS	$28,906,532		$28,906,532	$35,000,000		
10-1-92	(1,505,000)		(1,505,000)	35,000,000	11.020%	Annual Rate
04-1-93	(1,505,000)		(1,505,000)	35,000,000		
10-1-93	(1,505,000)		(1,505,000)	35,000,000		
04-1-94	(1,505,000)		(1,505,000)	35,000,000		
10-1-94	(1,505,000)		(1,505,000)	35,000,000		
04-1-95	(1,505,000)		(1,505,000)	35,000,000		
10-1-95	(1,505,000)		(1,505,000)	35,000,000		
04-1-96	(1,505,000)		(1,505,000)	35,000,000		
10-1-96	(1,505,000)		(1,505,000)	35,000,000		
04-1-97	(1,505,000)		(1,505,000)	35,000,000		
10-1-97	(1,505,000)		(1,505,000)	35,000,000		
04-1-98	(1,505,000)		(1,505,000)	35,000,000		
10-1-98	(1,505,000)		(1,505,000)	35,000,000		
04-1-99	(1,505,000)		(1,505,000)	35,000,000		
10-1-99	(1,505,000)		(1,505,000)	35,000,000		
04-1-00	(1,505,000)		(1,505,000)	35,000,000		
10-1-00	(1,505,000)		(1,505,000)	35,000,000		
04-1-01	(1,505,000)		(1,505,000)	35,000,000		
10-1-01	(1,505,000)		(1,505,000)	35,000,000		
04-1-02	(1,505,000)		(1,505,000)	35,000,000		
10-1-02	(1,505,000)		(1,505,000)	35,000,000		
04-1-03	(1,505,000)		(1,505,000)	35,000,000		
10-1-03	(1,505,000)		(1,505,000)	35,000,000		
04-1-04	(1,505,000)		(1,505,000)	35,000,000		
10-1-04	(1,505,000)		(1,505,000)	35,000,000		
1-05	(1,505,000)		(1,505,000)	35,000,000		
-1-05	(1,505,000)		(1,505,000)	35,000,000		
04-1-06	(1,505,000)		(1,505,000)	35,000,000		
10-1-06	(1,505,000)		(1,505,000)	35,000,000		
04-1-07	(1,505,000)		(1,505,000)	35,000,000		
10-1-07	(1,505,000)		(1,505,000)	35,000,000		
04-1-08	(1,505,000)		(1,505,000)	35,000,000		
10-1-08	(1,505,000)		(1,505,000)	35,000,000		
04-1-09	(1,505,000)		(1,505,000)	35,000,000		
10-1-09	(1,505,000)		(1,505,000)	35,000,000		
04-1-10	(1,505,000)		(1,505,000)	35,000,000		
10-1-10	(1,505,000)		(1,505,000)	35,000,000		
04-1-11	(1,505,000)		(1,505,000)	35,000,000		
10-1-11	(1,505,000)		(1,505,000)	35,000,000		
04-1-12	(1,505,000)	(35,000,000)	(36,505,000)	0		

2210-955

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.52% SECURED MEDIUM TERM NOTE

Last date of change: Oct-97

F:\FINRPT\CAPITAL\BONDS\[2210-955.xls]OCT 1997

Principal amount of issue:	**$15,000,000**
Stated interest rate:	**6.520%**
Annual Interest Payment:	**$978,000**

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$489,000				3.52% SemiAnnual Rate
9-30-97 NET PROCEEDS	$14,082,923		$14,082,923	$15,000,000	
4-1-98	(489,000)		(489,000)	15,000,000	7.11% Annual Rate
10-1-98	(489,000)		(489,000)	15,000,000	
4-1-99	(489,000)		(489,000)	15,000,000	
10-1-99	(489,000)		(489,000)	15,000,000	
4-1-00	(489,000)		(489,000)	15,000,000	
10-1-00	(489,000)		(489,000)	15,000,000	
4-1-01	(489,000)		(489,000)	15,000,000	
10-1-01	(489,000)		(489,000)	15,000,000	
4-1-02	(489,000)		(489,000)	15,000,000	
10-1-02	(489,000)		(489,000)	15,000,000	
4-1-03	(489,000)		(489,000)	15,000,000	
10-1-03	(489,000)		(489,000)	15,000,000	
4-1-04	(489,000)		(489,000)	15,000,000	
10-1-04	(489,000)	(15,000,000)	(15,489,000)	0	

2210-956

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.71% SECURED MEDIUM TERM NOTE

Last date of change: Oct-97

F:\FINRPT\CAPITAL\BONDS\[2210-956.xls]OCT 1997

Principal amount of issue:	**$15,000,000**
Stated interest rate:	**6.710%**
Annual Interest Payment:	**$1,006,500**

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$503,250				6.71% SemiAnnual Rate
9-30-97 NET PROCEEDS	$13,488,404		$13,488,404	$15,000,000	
4-1-98	(503,250)		(503,250)	15,000,000	6.84% Annual Rate
10-1-98	(503,250)		(503,250)	15,000,000	
4-1-99	(503,250)		(503,250)	15,000,000	
10-1-99	(503,250)		(503,250)	15,000,000	
4-1-00	(503,250)		(503,250)	15,000,000	
10-1-00	(503,250)		(503,250)	15,000,000	
4-1-01	(503,250)		(503,250)	15,000,000	
10-1-01	(503,250)		(503,250)	15,000,000	
4-1-02	(503,250)		(503,250)	15,000,000	
10-1-02	(503,250)		(503,250)	15,000,000	
4-1-03	(503,250)		(503,250)	15,000,000	
10-1-03	(503,250)		(503,250)	15,000,000	
4-1-04	(503,250)		(503,250)	15,000,000	
10-1-04	(503,250)		(503,250)	15,000,000	
4-1-05	(503,250)		(503,250)	15,000,000	
10-1-05	(503,250)		(503,250)	15,000,000	
4-1-06	(503,250)		(503,250)	15,000,000	
10-1-06	(503,250)		(503,250)	15,000,000	
4-1-07	(503,250)		(503,250)	15,000,000	
10-1-07	(503,250)		(503,250)	15,000,000	
4-1-08	(503,250)		(503,250)	15,000,000	
10-1-08	(503,250)		(503,250)	15,000,000	
4-1-09	(503,250)		(503,250)	15,000,000	
10-1-09	(503,250)	(15,000,000)	(15,503,250)	0	

2210-957

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
5.83% SECURED MEDIUM TERM NOTE

Last date of change: Dec-98

F:\FINRPT\CAPITAL\BONDS\[2210-957.xls]SEP 1998

Principal amount of issue:	**$15,000,000**
Stated interest rate:	**5.830%**
Annual Interest Payment:	**$874,500**

Payment Periods		SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate	
		$437,250				2.983%	SemiAnnual Rate
9-18-98	NET PROCEEDS	$14,813,914		$14,813,914	$15,000,000		
4-1-99		(437,250)		(437,250)	15,000,000	5.966%	Annual Rate
10-1-99		(437,250)		(437,250)	15,000,000		
4-1-00		(437,250)		(437,250)	15,000,000		
10-1-00		(437,250)		(437,250)	15,000,000		
4-1-01		(437,250)		(437,250)	15,000,000		
10-1-01		(437,250)		(437,250)	15,000,000		
4-1-02		(437,250)		(437,250)	15,000,000		
10-1-02		(437,250)		(437,250)	15,000,000		
4-1-03		(437,250)		(437,250)	15,000,000		
10-1-03		(437,250)		(437,250)	15,000,000		
4-1-04		(437,250)		(437,250)	15,000,000		
10-1-04		(437,250)		(437,250)	15,000,000		
4-1-05		(437,250)		(437,250)	15,000,000		
10-1-05		(437,250)		(437,250)	15,000,000		
4-1-06		(437,250)		(437,250)	15,000,000		
10-1-06		(437,250)		(437,250)	15,000,000		
4-1-07		(437,250)		(437,250)	15,000,000		
10-1-07		(437,250)		(437,250)	15,000,000		
4-1-08		(437,250)		(437,250)	15,000,000		
10-1-08		(437,250)	(15,000,000)	(15,437,250)	0		

2210-952

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.65% POLLUTION CONTROL BOND - MERCER COUNTY

As of: Aug-93

F:\FINRPT\CAPITAL\BONDS\[2210-952.xls]AUG 1993

Principal amount of issue:	**$15,000,000**
Stated interest rate:	**6.650%**
Annual Interest Payment:	**$997,500**

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$498,750				7.580% SemiAnnual Rate
06-1-92 NET PROCEEDS	$14,061,276		$14,061,276	$15,000,000	
12-1-92	(498,750)		(498,750)	15,000,000	7.288% Annual Rate
06-1-93	(498,750)		(498,750)	15,000,000	
12-1-93	(498,750)		(498,750)	15,000,000	
06-1-94	(498,750)		(498,750)	15,000,000	
12-1-94	(498,750)		(498,750)	15,000,000	
06-1-95	(498,750)		(498,750)	15,000,000	
12-1-95	(498,750)		(498,750)	15,000,000	
06-1-96	(498,750)		(498,750)	15,000,000	
12-1-96	(498,750)		(498,750)	15,000,000	
06-1-97	(498,750)		(498,750)	15,000,000	
12-1-97	(498,750)		(498,750)	15,000,000	
06-1-98	(498,750)		(498,750)	15,000,000	
12-1-98	(498,750)		(498,750)	15,000,000	
06-1-99	(498,750)		(498,750)	15,000,000	
12-1-99	(498,750)		(498,750)	15,000,000	
06-1-00	(498,750)		(498,750)	15,000,000	
12-1-00	(498,750)		(498,750)	15,000,000	
06-1-01	(498,750)		(498,750)	15,000,000	
12-1-01	(498,750)		(498,750)	15,000,000	
06-1-02	(498,750)		(498,750)	15,000,000	
12-1-02	(498,750)		(498,750)	15,000,000	
06-1-03	(498,750)		(498,750)	15,000,000	
12-1-03	(498,750)		(498,750)	15,000,000	
06-1-04	(498,750)		(498,750)	15,000,000	
12-1-04	(498,750)		(498,750)	15,000,000	
06-1-05	(498,750)		(498,750)	15,000,000	
12-1-05	(498,750)		(498,750)	15,000,000	
06-1-06	(498,750)		(498,750)	15,000,000	
12-1-06	(498,750)		(498,750)	15,000,000	
[illegible]-1-07	(498,750)		(498,750)	15,000,000	
[illegible]-1-07	(498,750)		(498,750)	15,000,000	
[illegible]-1-08	(498,750)		(498,750)	15,000,000	
12-1-08	(498,750)		(498,750)	15,000,000	
06-1-09	(498,750)		(498,750)	15,000,000	
12-1-09	(498,750)		(498,750)	15,000,000	
06-1-10	(498,750)		(498,750)	15,000,000	
12-1-10	(498,750)		(498,750)	15,000,000	
06-1-11	(498,750)		(498,750)	15,000,000	
12-1-11	(498,750)		(498,750)	15,000,000	
06-1-12	(498,750)		(498,750)	15,000,000	
12-1-12	(498,750)		(498,750)	15,000,000	
06-1-13	(498,750)		(498,750)	15,000,000	
12-1-13	(498,750)		(498,750)	15,000,000	
06-1-14	(498,750)		(498,750)	15,000,000	
12-1-14	(498,750)		(498,750)	15,000,000	
06-1-15	(498,750)		(498,750)	15,000,000	
12-1-15	(498,750)		(498,750)	15,000,000	
06-1-16	(498,750)		(498,750)	15,000,000	
12-1-16	(498,750)		(498,750)	15,000,000	
06-1-17	(498,750)		(498,750)	15,000,000	
12-1-17	(498,750)		(498,750)	15,000,000	
06-1-18	(498,750)		(498,750)	15,000,000	
12-1-18	(498,750)		(498,750)	15,000,000	
06-1-19	(498,750)		(498,750)	15,000,000	
12-1-19	(498,750)		(498,750)	15,000,000	
06-1-20	(498,750)		(498,750)	15,000,000	
12-1-20	(498,750)		(498,750)	15,000,000	
06-1-21	(498,750)		(498,750)	15,000,000	
12-1-21	(498,750)		(498,750)	15,000,000	
06-1-22	(498,750)	(15,000,000)	(15,498,750)	0	

2210-953

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.65% POLLUTION CONTROL BOND - RICHLAND COUNTY

As of: Aug-93

F:\FINRPT\CAPITAL\BONDS\[2210-953.xls]AUG 1993

Principal amount of issue:	$3,250,000
Stated interest rate:	6.650%
Annual Interest Payment:	$216,125

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$108,063				3.558% SemiAnnual Rate
06-1-92 NET PROCEEDS	$3,063,677		$3,063,677	$3,250,000	
12-1-92	(108,063)		(108,063)	3,250,000	7.243% Annual Rate
06-1-93	(108,063)		(108,063)	3,250,000	
12-1-93	(108,063)		(108,063)	3,250,000	
06-1-94	(108,063)		(108,063)	3,250,000	
12-1-94	(108,063)		(108,063)	3,250,000	
06-1-95	(108,063)		(108,063)	3,250,000	
12-1-95	(108,063)		(108,063)	3,250,000	
06-1-96	(108,063)		(108,063)	3,250,000	
12-1-96	(108,063)		(108,063)	3,250,000	
06-1-97	(108,063)		(108,063)	3,250,000	
12-1-97	(108,063)		(108,063)	3,250,000	
06-1-98	(108,063)		(108,063)	3,250,000	
12-1-98	(108,063)		(108,063)	3,250,000	
06-1-99	(108,063)		(108,063)	3,250,000	
12-1-99	(108,063)		(108,063)	3,250,000	
06-1-00	(108,063)		(108,063)	3,250,000	
12-1-00	(108,063)		(108,063)	3,250,000	
06-1-01	(108,063)		(108,063)	3,250,000	
12-1-01	(108,063)		(108,063)	3,250,000	
06-1-02	(108,063)		(108,063)	3,250,000	
12-1-02	(108,063)		(108,063)	3,250,000	
06-1-03	(108,063)		(108,063)	3,250,000	
12-1-03	(108,063)		(108,063)	3,250,000	
06-1-04	(108,063)		(108,063)	3,250,000	
12-1-04	(108,063)		(108,063)	3,250,000	
06-1-05	(108,063)		(108,063)	3,250,000	
12-1-05	(108,063)		(108,063)	3,250,000	
06-1-06	(108,063)		(108,063)	3,250,000	
12-1-06	(108,063)		(108,063)	3,250,000	
[illegible]-1-07	(108,063)		(108,063)	3,250,000	
[illegible]1-07	(108,063)		(108,063)	3,250,000	
[illegible]-1-08	(108,063)		(108,063)	3,250,000	
12-1-08	(108,063)		(108,063)	3,250,000	
06-1-09	(108,063)		(108,063)	3,250,000	
12-1-09	(108,063)		(108,063)	3,250,000	
06-1-10	(108,063)		(108,063)	3,250,000	
12-1-10	(108,063)		(108,063)	3,250,000	
06-1-11	(108,063)		(108,063)	3,250,000	
12-1-11	(108,063)		(108,063)	3,250,000	
06-1-12	(108,063)		(108,063)	3,250,000	
12-1-12	(108,063)		(108,063)	3,250,000	
06-1-13	(108,063)		(108,063)	3,250,000	
12-1-13	(108,063)		(108,063)	3,250,000	
06-1-14	(108,063)		(108,063)	3,250,000	
12-1-14	(108,063)		(108,063)	3,250,000	
06-1-15	(108,063)		(108,063)	3,250,000	
12-1-15	(108,063)		(108,063)	3,250,000	
06-1-16	(108,063)		(108,063)	3,250,000	
12-1-16	(108,063)		(108,063)	3,250,000	
06-1-17	(108,063)		(108,063)	3,250,000	
12-1-17	(108,063)		(108,063)	3,250,000	
06-1-18	(108,063)		(108,063)	3,250,000	
12-1-18	(108,063)		(108,063)	3,250,000	
06-1-19	(108,063)		(108,063)	3,250,000	
12-1-19	(108,063)		(108,063)	3,250,000	
06-1-20	(108,063)		(108,063)	3,250,000	
12-1-20	(108,063)		(108,063)	3,250,000	
06-1-21	(108,063)		(108,063)	3,250,000	
12-1-21	(108,063)		(108,063)	3,250,000	
06-1-22	(108,063)	(3,250,000)	(3,358,063)	0	

2210-954

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.65% POLLUTION CONTROL BOND - MORTON COUNTY

As of: Aug-93

F:\FINRPT\CAPITAL\BONDS\[2210-954.xls]AUG 1993

Principal amount of issue:	$2,600,000
Stated interest rate:	6.650%
Annual Interest Payment:	$172,900

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$86,450				3.607% SemiAnnual Rate
06-1-92 NET PROCEEDS	$2,420,986		$2,420,986	$2,600,000	
12-1-92	(86,450)		(86,450)	2,600,000	7.344% Annual Rate
06-1-93	(86,450)		(86,450)	2,600,000	
12-1-93	(86,450)		(86,450)	2,600,000	
06-1-94	(86,450)		(86,450)	2,600,000	
12-1-94	(86,450)		(86,450)	2,600,000	
06-1-95	(86,450)		(86,450)	2,600,000	
12-1-95	(86,450)		(86,450)	2,600,000	
06-1-96	(86,450)		(86,450)	2,600,000	
12-1-96	(86,450)		(86,450)	2,600,000	
06-1-97	(86,450)		(86,450)	2,600,000	
12-1-97	(86,450)		(86,450)	2,600,000	
06-1-98	(86,450)		(86,450)	2,600,000	
12-1-98	(86,450)		(86,450)	2,600,000	
06-1-99	(86,450)		(86,450)	2,600,000	
12-1-99	(86,450)		(86,450)	2,600,000	
06-1-00	(86,450)		(86,450)	2,600,000	
12-1-00	(86,450)		(86,450)	2,600,000	
06-1-01	(86,450)		(86,450)	2,600,000	
12-1-01	(86,450)		(86,450)	2,600,000	
06-1-02	(86,450)		(86,450)	2,600,000	
12-1-02	(86,450)		(86,450)	2,600,000	
06-1-03	(86,450)		(86,450)	2,600,000	
12-1-03	(86,450)		(86,450)	2,600,000	
06-1-04	(86,450)		(86,450)	2,600,000	
12-1-04	(86,450)		(86,450)	2,600,000	
06-1-05	(86,450)		(86,450)	2,600,000	
12-1-05	(86,450)		(86,450)	2,600,000	
06-1-06	(86,450)		(86,450)	2,600,000	
12-1-06	(86,450)		(86,450)	2,600,000	
06-1-07	(86,450)		(86,450)	2,600,000	
-1-07	(86,450)		(86,450)	2,600,000	
-1-08	(86,450)		(86,450)	2,600,000	
12-1-08	(86,450)		(86,450)	2,600,000	
06-1-09	(86,450)		(86,450)	2,600,000	
12-1-09	(86,450)		(86,450)	2,600,000	
06-1-10	(86,450)		(86,450)	2,600,000	
12-1-10	(86,450)		(86,450)	2,600,000	
06-1-11	(86,450)		(86,450)	2,600,000	
12-1-11	(86,450)		(86,450)	2,600,000	
06-1-12	(86,450)		(86,450)	2,600,000	
12-1-12	(86,450)		(86,450)	2,600,000	
06-1-13	(86,450)		(86,450)	2,600,000	
12-1-13	(86,450)		(86,450)	2,600,000	
06-1-14	(86,450)		(86,450)	2,600,000	
12-1-14	(86,450)		(86,450)	2,600,000	
06-1-15	(86,450)		(86,450)	2,600,000	
12-1-15	(86,450)		(86,450)	2,600,000	
06-1-16	(86,450)		(86,450)	2,600,000	
12-1-16	(86,450)		(86,450)	2,600,000	
06-1-17	(86,450)		(86,450)	2,600,000	
12-1-17	(86,450)		(86,450)	2,600,000	
06-1-18	(86,450)		(86,450)	2,600,000	
12-1-18	(86,450)		(86,450)	2,600,000	
06-1-19	(86,450)		(86,450)	2,600,000	
12-1-19	(86,450)		(86,450)	2,600,000	
06-1-20	(86,450)		(86,450)	2,600,000	
12-1-20	(86,450)		(86,450)	2,600,000	
06-1-21	(86,450)		(86,450)	2,600,000	
12-1-21	(86,450)		(86,450)	2,600,000	
06-1-22	(86,450)	(2,600,000)	(2,686,450)	0	

2240-928

MONTANA-DAKOTA UTILITIES CO.
COST OF MONEY CALCULATION
6.2% POLLUTION CONTROL BOND - GRANT COUNTY

Principal amount of issue:	**$5,600,000**	F:\FINRPT\CAPITAL\BONDS\[2210-928.xls]A
Stated interest rate:	**6.200%**	
Annual Interest Payment:	**$347,200**	

Payment Periods	SemiAnnual Interest Pmt's.	Principal Payment	Total Payment	Balance Outstanding	Effective Interest Rate
	$173,600				[redacted] SemiAnnual Rate
03-1-74 NET PROCEEDS	$5,427,042		$5,427,042	$5,600,000	
09-1-74	(173,600)		(173,600)	5,600,000	[redacted] Annual Rate
03-1-75	(173,600)		(173,600)	5,600,000	
09-1-75	(173,600)		(173,600)	5,600,000	
03-1-76	(173,600)		(173,600)	5,600,000	
09-1-76	(173,600)		(173,600)	5,600,000	
03-1-77	(173,600)		(173,600)	5,600,000	
09-1-77	(173,600)		(173,600)	5,600,000	
03-1-78	(173,600)		(173,600)	5,600,000	
09-1-78	(173,600)		(173,600)	5,600,000	
03-1-79	(173,600)		(173,600)	5,600,000	
09-1-79	(173,600)		(173,600)	5,600,000	
03-1-80	(173,600)		(173,600)	5,600,000	
09-1-80	(173,600)		(173,600)	5,600,000	
03-1-81	(173,600)		(173,600)	5,600,000	
09-1-81	(173,600)		(173,600)	5,600,000	
03-1-82	(173,600)		(173,600)	5,600,000	
09-1-82	(173,600)		(173,600)	5,600,000	
03-1-83	(173,600)		(173,600)	5,600,000	
09-1-83	(173,600)		(173,600)	5,600,000	
03-1-84	(173,600)		(173,600)	5,600,000	
09-1-84	(173,600)		(173,600)	5,600,000	
03-1-85	(173,600)		(173,600)	5,600,000	
09-1-85	(173,600)		(173,600)	5,600,000	
03-1-86	(173,600)		(173,600)	5,600,000	
09-1-86	(173,600)		(173,600)	5,600,000	
03-1-87	(173,600)		(173,600)	5,600,000	
09-1-87	(173,600)		(173,600)	5,600,000	
03-1-88	(173,600)		(173,600)	5,600,000	
09-1-88	(173,600)		(173,600)	5,600,000	
03-1-89	(173,600)		(173,600)	5,600,000	
1-89	(173,600)		(173,600)	5,600,000	
1-90	(173,600)	(200,000)	(373,600)	5,400,000	
09-1-90	(167,400)		(167,400)	5,400,000	
03-1-91	(167,400)	(200,000)	(367,400)	5,200,000	
09-1-91	(161,200)		(161,200)	5,200,000	
03-1-92	(161,200)	(200,000)	(361,200)	5,000,000	
09-1-92	(155,000)		(155,000)	5,000,000	
03-1-93	(155,000)	(200,000)	(355,000)	4,800,000	
09-1-93	(148,800)		(148,800)	4,800,000	
03-1-94	(148,800)	(200,000)	(348,800)	4,600,000	
09-1-94	(142,600)		(142,600)	4,600,000	
03-1-95	(142,600)	(300,000)	(442,600)	4,300,000	
09-1-95	(133,300)		(133,300)	4,300,000	
03-1-96	(133,300)	(300,000)	(433,300)	4,000,000	
09-1-96	(124,000)		(124,000)	4,000,000	
03-1-97	(124,000)	(300,000)	(424,000)	3,700,000	
09-1-97	(114,700)		(114,700)	3,700,000	
03-1-98	(114,700)	(300,000)	(414,700)	3,400,000	
09-1-98	(105,400)		(105,400)	3,400,000	
03-1-99	(105,400)	(300,000)	(405,400)	3,100,000	
09-1-99	(96,100)		(96,100)	3,100,000	
03-1-00	(96,100)	(300,000)	(396,100)	2,800,000	
09-1-00	(86,800)		(86,800)	2,800,000	
03-1-01	(86,800)	(300,000)	(386,800)	2,500,000	
09-1-01	(77,500)		(77,500)	2,500,000	
03-1-02	(77,500)	(500,000)	(577,500)	2,000,000	
09-1-02	(62,000)		(62,000)	2,000,000	
03-1-03	(62,000)	(500,000)	(562,000)	1,500,000	
09-1-03	(46,500)		(46,500)	1,500,000	
03-1-04	(46,500)	(1,500,000)	(1,546,500)	0	

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JULY 19, 2001
CASE NO. PU-399-01-186

The following data requests relate to the responses provided Montana-Dakota Utilities ("MDU") under cover letter dated July 2, 2001.
With respect to Response No. 2, Attachment 2-A

Request No. 10:

Please provide a full explanation of the amortization presented on page 3 of this Attachment, including the cause of the loss, the calculation of the amount, and the amortization period. State the justification for incurring this loss and provide copies of any approvals of this loss by regulatory commission as a cost of service to ratepayers.

Response:

The referenced amortization relates to the costs associated with the redemption of the $50 million 91/8% bond issue and any unamortized discount and expense. The loss on redemption and associated expenses are amortized over the original life of the bond as required by FERC accounting rules. Montana-Dakota was able to lower its overall cost of debt by refinancing the debt, taking into account the costs associated with the redemption and issuance of the new debt. Please see Attachment A for the calculation of the amortization amount and Attachment B for a copy of the applicable FERC rules. Please see Response No. 8, Attachment B for the relevant portion of the Order in Montana Docket D95.7.90 that addressed and approved the costs associated with the reacquisition of debt. Such costs were also included in the capital structure in cases filed in North Dakota, South Dakota and Wyoming in 1993-1994. These cases were settled and the capital structure was not specifically addressed in the orders or settlement agreements.

MONTANA-DAKOTA UTILITES CO.
AMORTIZATION OF LOSS ON REDEMPTION
9 1/8% SERIES DUE MAY 15, 2006
ACCOUNT#: 1898.844
$25,000,000 REDEEMED ON JUNE 1, 1996
$5,000,000 SINKING REDEMPTION ON NOVEMBER 17, 1997
$20,000,000 REDEEMED ON MAY 15, 1998

TOTAL LOSS ON REDEMPTION: 7,424,149 67

YEAR	BALANCE	4 1/2 MONTHS	7 1/2 MONTHS	10 1/2 MONTHS	1 1/2 MONTHS	TOTAL	ANNUAL %	ANNUAL AMORT.	JANUARY AMORT.	FEB - DEC AMORT.	JUL- DEC 1996 JUN - DEC 1998 AMORT	JUNE 1998 & BEG/END MAY AMORT.	
1991	50,000,000		375,000,000			375,000,000	—	289,519 83		38,602 64		19,301.35	
1992	50,000,000	225,000,000	375,000,000			600,000,000	---	462,927.49	38,577 19	38,577 30			
1993	50,000,000	225,000,000	375,000,000			600,000,000	---	462,927 49	38,577.19	38,577.30			
1994	50,000,000	225,000,000	375,000,000			600,000,000	---	462,927.49	38,577.19	38,577.30			
1995	50,000,000	225,000,000	375,000,000			600,000,000	---	462,927.49	38,577 19	38,577.30			
1996	50,000,000	225,000,000	375,000,000			600,000,000	---	607,545.99	38,577.19	38,577 30	20,659 79	20,659 76	
1997	45,000,000			525,000,000	67,500,000	592,500,000	---	701,942 68	58,495 26	58,495 22			
1998	40,000,000			472,500,000	60,000,000	532,500,000	---	754,329.66	52,568 74	52,568 72	16,435 33	8,217 69	
1999	35,000,000			420,000,000	52,500,000	472,500,000	---	734,653 62	61,221 08	61,221 14			
2000	30,000,000			367,500,000	45,000,000	412,500,000	---	641,614 60	53,467 81	53,467 89			
2001	25,000,000			315,000,000	37,500,000	352,500,000	---	548,429.21	45,702 48	45,702 43			
2002	20,000,000			262,500,000	30,000,000	292,500,000	---	454,705 16	37,892.17	37,892 09			
2003	15,000,000			210,000,000	22,500,000	232,500,000	---	361,666 15	30,138 80	30,138.85			
2004	10,000,000			157,500,000	15,000,000	172,500,000	---	268,827.14	22,385.65	22,385.59			
2005	5,000,000			105,000,000	7,500,000	112,500,000	---	174,667.72	14,555.68	14,555 64			
2006	0	22,500,000		0	0	22,500,000	---	34,737.95	7,719.54	7,719.55		3,859.76	
	525,000,000	1,147,500,000	2,250,000,000	2,835,000,000	337,500,000	6,570,000,000	0 00%	7,424,149 67	577,053.16	6,556,051.90	239,006 05	52,038 56	7,424,149 67

Response No. 10
Attachment A

FERC Acctg + Rptg Requirements
for Natural Gas & Electric Companies

[¶ 20,028]

17. *Long-Term Debt: Premium, Discount and Expense, and Gain or Loss on Reacquisition*—A. *Premium, discount and expense.* A separate premium, discount and expense account shall be maintained for each class and series of long-term debt (including receivers' certificates) issued or assumed by the utility. The premium will be recorded in account 225, Unamortized Premium on Long-Term Debt, the discount will be recorded in account 226, Unamortized Discount on Long-Term Debt—Debit, and the expense of issuance shall be recorded in account 181, Unamortized Debt Expense.

The premium, discount and expense shall be amortized over the life of the respective issues under a plan which will distribute the amounts equitably over the life of the securities. The amortization shall be on a monthly basis, and amounts thereof relating to discount and expense shall be charged to account 428, Amortization of Debt Discount and Expense. The amounts relating to premium shall be credited to account 429, Amortization of Premium on Debt—Credit.

B. *Reacquisition, without refunding.* When long-term debt is reacquired or redeemed without being converted into another form of long-term debt and when the transaction is not in connection with a refunding operation (primarily redemptions for sinking fund purposes), the difference between the amount paid upon reacquisition and the face value; plus any un- amortized premium less any related unamortized debt expense and reacquisition costs; or less any unamortized discount, related debt expense and reacquisition costs applicable to the debt redeemed, retired and canceled, shall be included in account 189, Unamortized Loss on Reacquired Debt, or account 257, Unamortized Gain on Reacquired Debt, as appropriate. The utility shall amortize the recorded amounts equally on a monthly basis over the remaining life of the respective security issues (old original debt). The amounts so amortized shall be charged to account 428.1, Amortization of Loss on Reacquired Debt, or credited to account 429.1, Amortization of Gain on Reacquired Debt—Credit, as appropriate.

C. *Reacquisition, with refunding.* When the redemption of one issue or series of bonds or other long-term obligations is financed by another issue or series before the maturity date of the first issue, the difference between the amount paid upon refunding and the face value; plus any unamortized premium less related debt expense or less any unamortized discount and related debt expense, applicable to the debt refunded, shall be included in account 189, Unamortized Loss on Reacquired Debt, or account 257, Unamortized Gain on Reacquired Debt, as appropriate. The utility may elect to account for such amounts as follows:

(1) Write them off immediately when the amounts are insignificant.

(2) Amortize them by equal monthly amounts over the remainder of the original life of the issue retired, or

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JULY 19, 2001
CASE NO. PU-399-01-186

The following data requests relate to the responses provided Montana-Dakota Utilities ("MDU") under cover letter dated July 2, 2001.
With respect to your response to Request No. 5:

Request No. 15:

Is the full $40 million credit allowance outstanding at all times? If not, what was the amount outstanding as of December 31, 2000? What was the average amount outstanding during calendar year 2000?

Response:

The $40 million credit allowance was outstanding in various amounts throughout 2000. The amount outstanding at December 31, 2000 was $40 million. The average amount outstanding during calendar year 2000 was $1.3 million.

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED JULY 19, 2001
CASE NO. PU-399-01-186

The following data requests relate to the responses provided Montana-Dakota Utilities ("MDU") under cover letter dated July 2, 2001.
With respect to your response to Request No. 5:

Request No. 20:

With respect to your response to Request No. 13, have any other regulatory commissions prescribed equity returns for MDU's utility operations since 1987? If so, please identify the commission, the case and the date, and provide a copy of the decision(s).

Response:

State	Date	Case/Docket No.	ROE	Attachment
Electric				
Montana	3/87	86.6.28	12.30%	A
Wyoming	12/93	20004-ER-93-20	1/	B
Gas				
Montana	5/96	D95.7.90	12.00%	C
North Dakota	11/94	PU-399-94-297	1/	D
South Dakota	12/94	NG94-012	11.50%	E
Wyoming	12/93	30013-GR-93-47	1/	F

1/ Settlement, ROE not specified.

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MAR 27 1987

REGULATORY
AFFAIRS

Service Date: MAR 24 1987

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of MONTANA-DAKOTA UTILITIES for Authority to Establish Increased Rates for Electric Service.	))))	UTILITY DIVISION DOCKET NO. 86.5.28 ORDER NO. 5219b

strength, price stability, beta, and safety. These characteristics, when taken together, form a composite ranking of risk. Examination of these composite rankings showed that only 7 of the 45 companies have risks greater than MDU (MCC Exh. 4, Exh. BLC-2, Sch. 4). The Commission also considered the fact that both witnesses' DCF analysis yielded higher expected returns for MDU Resources than for their comparable companies. The Commission believes this information is helpful in determining a fair rate of return on the Company's common equity. The Commission accepts 12.30 percent as MDU's cost of common equity for electric operations.

Rate of Return

56. Based on the findings for long term debt, preferred stock, and common equity in this proceeding, the following capital structure and costs resulting in an 10.655 percent overall rate of return are determined appropriate:

Description	Ratio	Cost	Weighted Cost
First Mort. Bonds	44.491%	10.232%	4.552%
Other L.T. Debt	8.681	8.222	0.714
Preferred Stock	11.280	9.019	1.017
Common Equity	35.548	12.300	4.372
Total	100%		10.655%

PART C

RATE BASE

57. Consistent with previous Commission decisions, both MDU and MCC proposed a 1985 average rate base, adjusted to include certain known and measurable changes. The Commission finds a 1985 average rate base, adjusted for certain known and measurable changes, to be appropriate in this proceeding.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC., FOR A GENERAL RATE INCREASE IN ITS WYOMING ELECTRIC UTILITY SERVICE RATES OF $378,569 PER ANNUM ($0.00198/KWH AVERAGE); AND METERING PROGRAM (POWERSTAT) WHEREBY THE UTILITY SEEKS TO NOT BE HELD RESPONSIBLE FOR INJURY OR DAMAGE WHEN A PARTICIPATING CUSTOMER'S POWER SHUTS OFF AUTOMATICALLY WHEN HIS POWER PURCHASE AMOUNT IS USED UP	DOCKET NO. 20004-ER-93-20
AND	
IN THE MATTER OF THE FILING BY MONTANA-DAKOTA UTILITIES COMPANY, DIVISION OF MDU RESOURCES GROUP, INC., OF ITS ELECTRIC INTEGRATED RESOURCE PLAN	DOCKET NO. 20004-ER-93-21

APPEARANCES

BRUCE S. ASAY, Cheyenne, Wyoming,
for Applicant/Respondent
Montana-Dakota Utilities Company,
a Division of MDU Resources Group, Inc.
(hereinafter referred to as MDU)

LEIGH E. STINNER, Cheyenne, Wyoming,
for Intervenor Consumer Representative Staff
of the Public Service Commission of Wyoming
(hereinafter referred to as Consumer Representative Staff)

LEONORA KNUTSON, Sheridan, Wyoming, Appearing Pro Se

HEARD BEFORE

Chairman Bil Tucker
Deputy Chairman John R. Smyth
Commissioner Steve Ellenbecker

Commissioner Ellenbecker presiding

b. No return on common equity was agreed to by the parties in this Stipulation and Agreement. However, the parties agree and stipulate that an overall just and reasonable authorized rate of return on Montana-Dakota's Wyoming rate base should be established at 9.936%.

c. Customer deposits have been deducted from Montana-Dakota's recoverable rate base amount in setting rates. In addition, Montana-Dakota's Wyoming operating costs include 6% of the Wyoming customer deposit amount as a reasonable test period operating expense.

11. The Financial Accounting Standards Board (FASB), in its statement of Financial Accounting Standards No. 106, requires that estimated future costs of post-retirement benefits other than pensions (PBOPs) be included as a financial reporting expense in the years that employees provide service. The parties agree and stipulate that Montana-Dakota should be allowed rate recovery of the full PBOP cost accrual. This results in a $84,933 adjustment to costs for Montana-Dakota's Wyoming electric operations. The parties agree that Montana-Dakota is currently performing a study to determine the most economic and beneficial funding mechanisms and will report the results of that study to the Commission by April 1, 1994. The parties shall have an opportunity to submit written comments and/or request a hearing relative to the study. The funding mechanism(s) that may be selected based on the study results shall be subject to Commission approval. It is further agreed that any amounts not funded by December 1, 1994, shall be

Service Date: April 17, 1996

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES COMPANY, Application for Authority to Increase Rates for Natural Gas Service in Montana.	)	UTILITY DIVISION
	)	DOCKET NO. D95.7.90
	)	ORDER NO. 5856b

RECEIVED
APR 18 1996
REGULATORY AFFAIRS

FINAL ORDER

APPEARANCES

FOR THE APPLICANT:

John Alke, Hughes, Kellner, Sullivan, and Alke, Attorneys at Law, 406 Fuller Avenue, P.O. Box 1166, Helena, Montana 59624-1166, and Douglas W. Schulz, Senior Attorney, Montana-Dakota Utilities Co., 400 North Fourth Street, Bismarck, North Dakota, 58501

FOR THE INTERVENORS:

Robert A. Nelson, Montana Consumer Counsel, and Mary Wright, Staff Attorney, Montana Consumer Counsel, 34 West Sixth Avenue, P.O. Box 201703, Helena Montana 59620-1703, for the Montana Consumer Counsel

FOR THE COMMISSION:

Ron Woods, Rate Analyst, Mike Lee, Rate Design Bureau Chief, Mike Sheard, Rate Analyst, and Martin Jacobson, Staff Attorney, 1701 Prospect Avenue, P.O. Box 202601, Helena, Montana 59620-2601

BEFORE:

NANCY MCCAFFREE, Chair
DAVE FISHER, Vice-Chair
BOB ANDERSON, Commissioner
DANNY OBERG, Commissioner
BOB ROWE, Commissioner

34. The indenture restatement, as alleged by MCC, did produce benefits for the shareholders of MDU. The revision loosened the restrictions on purchase of encumbered property, it gave the Company greater flexibility to get involved in other forms of energy supply and increased the amount of bonds that could be issued under the indenture. Since shareholders were the recipients of these benefits, the cost of the indenture revision should be their responsibility. It is estimated by MDU that included in the $15 million cost of refinancing is an estimated $50,000 cost incurred to have the original indenture restated. The number is an estimate. MDU was unable to determine, from the invoices received, the exact amount of the expense incurred and the amount stated could be more, or less, than that provided in the testimony. The Commission finds that MDU should reduce the costs included in its calculation of the effective cost of debt by $50,000, the estimated amount of the indenture revision costs.

Commission Decision on Cost of Capital

35. Based on the above findings and analyses, the Commission determines the following capital structure and composite cost of total capital to be reasonable:

	Amount (000)	Percent of Capitalization	Rate	Rate of Return
Long-Term Debt	$149,303	53.39%	10.212%[5]	5.452%
Preferred Stock	$ 5,050	1.81%	4.653%	0.084%
Common Stock	$ 30,934	44.81%	12.000%	5.377%
Total		100.00%		10.913%

Rate Base

36. In its application MDU proposed an average original cost depreciated rate base of $19,955,349. In prefiled direct

[5] In the compliance filing the effective cost of long term debt will be reduced to reflect the Commission's disallowance of $50,000 in bond indenture revision costs.

NOV 14 1994
REGULATORY AFFAIRS

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

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

Case No. PU-399-94-297

ORDER APPROVING SETTLEMENT

November 9, 1994

Preliminary Statement

On May 13, 1994, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. ("Montana-Dakota") filed a general gas rate application with the North Dakota Public Service Commission ("the Commission"), seeking approval to increase its rates for natural gas service in North Dakota. In its application Montana-Dakota sought a total annual revenue increase of $945,440.

On June 1, 1994, the Commission suspended the proposed rates and scheduled informal public input sessions on July 5, 1994, via video teleconferencing at several locations within the Company's gas service area, and setting the technical hearing on the application for November 9, 1994.

On June 1, 1994, the Commission issued its Procedural Order. The Procedural Order established dates for intervention, discovery deadlines and procedures for submission of prefiled testimony and exhibits, and provided for prehearing motions and conferences.

On July 5, 1994, the public input sessions were held as scheduled, at 12:15 P.M. (CDT) and 7 P.M. (CDT) in Bismarck, Dickinson, Devils Lake, Valley City, Minot, Williston and Jamestown.

On August 4, 1994, the Federal Executive Agencies ("FEA"), on behalf of the Minot Air Force Base, filed a petition to intervene. On August 29, 1994, the Commission issued an order granting intervention to FEA.

On November 2, 1994, the Commission Staff and Montana-Dakota filed a settlement agreement, with which FEA concurred. The agreement asked that the Commission approve an annual revenue increase of $565,000 to Montana-Dakota in its North Dakota gas utility operations, effective for bills rendered on and after November 15, 1994. The base rate for residential customers would increase from $5.50 to $6.50 for small meter residential customers and from $11.00 to $13.00 for large meter residential customers, from $7.50 to $8.50 for small meter commercial customers and from $15.00 to $17.00 for large meter commercial customers. The base rate for the Air Force would be increased from $500.00 to $750.00, and from $15.00 to $35.00 for P.A.R. sites. The small interruptible customers' base rate would increase from $15.00 to $35.00, and the base rate would remain at $450.00 for large interruptible customers. Overall the price of gas service would increase by 1.16% for residential customers and by 0.32% for commercial customers and remain unchanged for interruptible customers and the Air Force. The settlement agreement also provided for a return on rate base of 10.375%.

At the time originally scheduled for the technical hearing on November 9, 1994, the Commission heard testimony from both the Staff and Montana-Dakota regarding the effect of the settlement agreement on Montana-Dakota's operations and invited interested persons to make comments on the proposed settlement agreement.

On March 31, 1994, Montana-Dakota filed the Summary of Retiree Health Care and Life Benefits Funding Study, as required by Commission Orders dated January 18, 1994 and November 23, 1993. The Commission required that the funding study be addressed in this case. The Commission will hold a hearing concerning the issues pertaining to the funding study at 3:00 P.M. on December 7, 1994.

Based on the record in this matter, the Commission now issues its

Findings of Fact

1. The Commission has jurisdiction over the parties and the subject matter in this proceeding.

2. The capable parties have reasonably crafted the settlement agreement at issue herein.

3. The settlement agreement before us constitutes only a determination that it is in the

public interest, just and reasonable. The agreement is a negotiated dollar settlement, subject to Commission approval, and does not establish any principle or precedent, or specific amount of allowed expenses or rate base, or any specific level of overall cost of capital, for any specific test year.

4. The written settlement agreement, together with the information provided to the Commission prior to and at the hearing, provide adequate support for finding that the agreement is fair and reasonable.

5. Montana-Dakota's present authorized overall rate of return for its gas operation is 9.964%. Its current revenues are not sufficient to allow the Company to earn its authorized rate of return.

6. The stipulated annual revenue increase of $565,000 is fair and reasonable because it will allow Montana-Dakota's gas utility operation a fair opportunity to earn a reasonable return.

7. No person or party has expressed objection to acceptance of the stipulation for settlement of this matter.

From the foregoing Findings of Fact, the Commission issues the following:

Conclusions of Law

1. The Commission has jurisdiction over the parties and the subject matter of this hearing.

2. The Commission has the authority to approve the settlement agreement.

3. The settlement agreement is fair and reasonable and is in the public interest.

4. The settlement agreement does not violate any principle of law or policy.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

JAN 05 1995
REGULATORY AFFAIRS

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE NATURAL GAS RATES IN SOUTH DAKOTA	))))	ORDER APPROVING SETTLEMENT AGREEMENT REGARDING FAS 106 NG94-012

On June 30, 1994, Montana-Dakota Utilities Co. (MDU) filed with the Public Utilities Commission (Commission) an application for approval to increase its rates for natural gas service. MDU proposes a total increase of $1,110,539, which represents an overall increase of 3.7%. The proposed increase for residential customers would be 4.6% and firm general service customers rates would increase by 3.5%. The proposed rates would affect approximately 33,400 gas customers in South Dakota. The application does not affect the rates applicable to the customers receiving gas service in MDU's recent gas service expansion referred to as the East River Natural Gas System.

MDU asserts the rate increase is necessary "because certain operating costs, primarily plant investment and related costs, continue to increase along with moderate labor increases above the amounts approved in the last general rate case filed in 1993."

By Order dated July 27, 1994, the Commission set August 19, 1994, as the deadline for intervention, and ordered MDU to deposit up to $75,000 in the SDPUC Rate Case Fund. On August 8, 1994, the Commission received a petition to intervene from the Federal Executive Agencies (FEA). By Order dated September 6, 1994, the Commission granted FEA's petition to intervene.

On November 18, 1994, the Commission was informed by Commission Staff (Staff) that a negotiated settlement between the parties appeared imminent. In contemplation of settlement, Staff proposed that the Commission set a date for hearing and presentation of the potential settlement. The Commission set the hearing date for November 28, 1994.

At the hearing, the Commission received a Settlement Agreement reached by MDU, Staff, and FEA. The Settlement Agreement set forth the bases for approval by the parties who jointly recommended a rate increase and other matters.

The settled increase for the residential customer class would be 2.3% and for the Firm General Service customer class the increase would be 1.4%. The issue of Financial Accounting Standards 106 (FAS 106) accrual v. Pay-as-you-go (PAYGO) accounting for

Copies to: D. Fox
D. Bael
V. Faile
D. Schulz

STATE OF SOUTH DAKOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the Matter of the Application Of Montana-Dakota Utilities Co. For Authority to Establish Increased Rates For Natural Gas Service In The State of South Dakota	)))))	Docket No. NG94-012

SETTLEMENT AGREEMENT AMONG MONTANA-DAKOTA UTILITIES CO., COMMISSION STAFF AND INTERVENOR FEDERAL EXECUTIVE AGENCIES

This Settlement Agreement is made and entered into by and among Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota" or "Company"), Intervenor Federal Executive Agencies ("Agencies") and the Staff of the South Dakota Public Utilities Commission ("Staff").

I.

BACKGROUND

On June 30, 1994, Montana-Dakota filed an application with the Public Utilities Commission ("Commission") for increased retail natural gas rates for South Dakota customers, except those customers receiving gas service in Montana-Dakota's recent gas system expansion referred to as the East River Natural Gas System.

Montana-Dakota's application, based on a December 31, 1993 test year adjusted for known and measurable changes through December 31, 1994, sought approval of rates which would yield Montana-Dakota additional annual revenues of $1,110,539 or a 3.7% overall increase.

(no change) for large interruptible customers.

Article III. SFAS 106 Costs

The cost increase due to increased benefit costs resulting from a mandate by the Financial Accounting Standards Board referred to as SFAS 106 shall be a reserved issue to be decided by the Commission in this Docket after a hearing and such decision shall be subject to appeal as provided by law. The settlement increase set forth in this Agreement reflects the current expense on a pay-as-you-go basis for such benefit costs.

Article IV. Other Conditions

The return on common equity agreed to by the parties to this Agreement is 11.5% which results in an overall rate of return on Company's rate base of 10.149%, subject to modification of the final revenue requirement by the Commission or court after a determination of any reserved issue. The rate base to which the overall rate of return applies is agreed to be $10,966,000 and the overall cost of service, reflecting the pay-as-you-go basis for SFAS 106 which issue is reserved for hearing in Article III above, is $29,469,000, (excluding other operating revenues of $80,085) including the annual increase of $500,000.

Article V. General Conditions

1. It is agreed that this Agreement is a negotiated dollar settlement and establishes no principles or precedent and shall not be deemed to foreclose Montana-Dakota or Staff or any other person from making any contention in any proceeding or investigation, including the right of the Staff or any other interested person to seek a rate change if justified on any basis.

FEB 1994
REGULATORY AFFAIRS

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES COMPANY FOR AUTHORITY TO INCREASE RATES FOR WYOMING GAS UTILITY SERVICE $430,123 PER ANNUM (4.322% AVERAGE) INCLUDING RATE INCREASES OF 5.29% AND 3.48% FOR RESIDENTIAL AND FIRM COMMERCIAL CUSTOMERS, AND DECREASES FOR SMALL INTERRUPTIBLE CUSTOMERS, AND TO AMEND TARIFF PROVISIONS	DOCKET NO. 30013-GR-93-47
AND	
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES COMPANY FOR AUTHORITY TO IMPLEMENT REVISIONS TO ITS NATURAL GAS TARIFFS TO REFLECT THE EFFECTS OF THE FEDERAL ENERGY REGULATORY COMMISSION ORDER 636	DOCKET NO. 30013-GT-93-45
AND	
IN THE MATTER OF THE INVESTIGATION BY THE PUBLIC SERVICE COMMISSION OF WYOMING, ON ITS OWN MOTION, INTO THE NATURAL GAS PURCHASE AND ACQUISITION PRACTICES, POLICIES, AND PROCEDURES OF MONTANA-DAKOTA UTILITIES COMPANY, DIVISION OF MDU RESOURCES GROUP, INC.	DOCKET NO. 30013-GI-92-36

APPEARANCES

BRUCE S. ASAY, Cheyenne, Wyoming,
for Applicant/Respondent
Montana-Dakota Utilities Company,
a Division of MDU Resources Group, Inc.
(hereinafter referred to as MDU)

LEIGH E. STINNER, Cheyenne, Wyoming,
for Intervenor Consumer Representative Staff
of the Public Service Commission of Wyoming
(hereinafter referred to as Consumer Representative Staff)

concluding in agreement that for purposes of this Stipulation:

a. The measured utility rate base is the net amount upon which the utility should be authorized to earn a return in Wyoming. It is agreed and stipulated that Montana-Dakota's Wyoming rate base upon which rates are hereby based is $3,762,871. All utility assets included in the calculation of utility rate base are in service and actively being used to provide service to Wyoming customers.

b. No return on common equity was agreed to by the parties in this Stipulation and Agreement. However, the parties agree and stipulate that an overall just and reasonable authorized rate of return on Montana-Dakota's Wyoming rate base should be established at 9.93~~6~~% (9.63).

c. Customer deposits have been deducted from Montana-Dakota's recoverable rate base amount in setting rates. In addition, Montana-Dakota's Wyoming operating costs include 6% of the Wyoming customer deposit amount as a reasonable test period operating expense.

d. The parties agree and stipulate that Montana-Dakota's Integrated Resource Plan (IRP) costs should be included as an allowable expense amortized over five years as proposed by Montana-Dakota in its application. The Gas IRP was required to be performed by Montana-Dakota through a Commission Order in Docket No. 30013-GI-92-36. Subsequent to that Order, Montana-Dakota retained the services, through competitive bidding, of Metzler & Associates to assist in preparing the IRP. Montana-Dakota has held

MONTANA-DAKOTA UTILITIES CO.
REQUESTS FOR INFORMATION
CHARLES KING ON BEHALF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION STAFF
DATED AUGUST 15, 2001
CASE NO. PU-399-01-186

The following data request relates to the responses provided by Montana-Dakota Utilities ("MDU") under cover letter dated August 2, 2001.

1. With respect to the Company's response to Request No. 13, please provide a schedule of the amortizations under FERC Accounts 428 (Amortization of Debt Discount and Expense) and 428.1 (Amortization of Loss on Reacquired Debt) over the five years, 2001 through 2005.

Response:

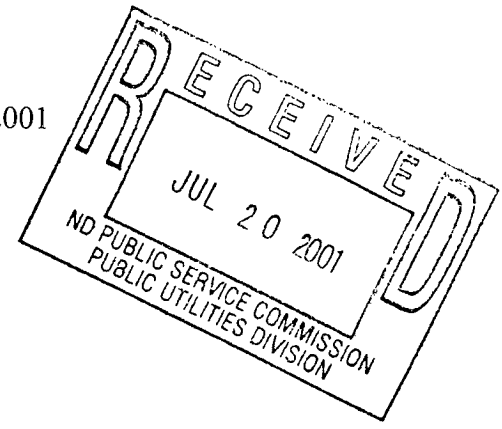
Please see Attachment A.

MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA PSC REQUEST
15-Aug-01

	YEAR				
	2001	**2002**	**2003**	**2004**	**2005**
Bond Issue #					
	Amortization of Discount Expense				
951	4,445.00	4,445.00	4,445.00	4,445.00	4,445.00
	Amortization of Debt Expense				
928	3,095.95	2,525.18	1,919.83	639.92	-
950	26,450.05	26,450.05	26,450.05	26,450.05	26,450.05
951	28,670.90	28,670.90	28,670.90	28,670.90	28,670.90
952	18,775.92	18,775.92	18,775.92	18,775.92	18,775.92
953	4,335.12	4,335.12	4,335.12	4,335.12	4,335.12
954	3,548.16	3,548.16	3,548.16	3,548.16	3,548.16
955	18,037.50	18,037.50	18,037.50	13,528.09	
956	12,992.85	12,992.85	12,992.85	12,992.85	12,992.85
957	18,542.14	18,542.14	18,542.14	18,542.14	18,542.14
Total Acct # 4280	**138,893.59**	**138,322.82**	**137,717.47**	**131,928.15**	**117,760.14**
	Amortization of Loss on Bond Redemption				
944	548,429.21	454,705.16	361,666.15	268,627.14	174,667.72
950	232,763.57	232,763.57	232,763.57	232,763.57	232,763.57
951	271,557.49	271,558.49	271,559.49	271,560.49	271,561.49
952	12,514.80	12,514.80	12,514.80	12,514.80	12,514.80
953	1,875.60	1,875.60	1,875.60	1,875.60	1,875.60
954	2,418.96	2,418.96	2,418.96	2,418.96	2,418.96
955	112,973.47	112,973.47	112,973.47	84,730.12	-
956	112,973.47	112,973.47	112,973.47	112,973.47	112,973.47
Total Acct # 4281	**1,295,506.57**	**1,201,783.52**	**1,108,745.51**	**987,464.15**	**808,775.61**
Total Amortization - Debt Items	**1,434,400.16**	**1,340,106.34**	**1,246,462.98**	**1,119,392.30**	**926,535.75**

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS

July 17, 2001



Michael Diller
Director of Accounting
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, ND 5805-0480

Dear Mr. Diller:

Enclosed herewith is signed Contract No. PU-427-01 for consulting services in Case No. PU-399-01-186 involving the Montana Dakota Utilities ("MDU"). I have retained one copy of this contract for our files.

I have received the responses of MDU to our data requests. Assuming they are reasonably responsive, I hope to have a draft of the full rate-of-return testimony by the time I leave for vacation, July 31. I will keep you posted as to my progress.

Sincerely

Charles W. King

13 **PU-399-01-186** Pages: 5

Signed Contract No. PU-427-01
by Snavely King Majoros O'Connor & Lee, Inc.
07/20/2001 CC: Comm Legal Illona, Pat, Jerry Mike

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: July 11, 2001

Anthony T. Clark	Susan E. Wefald	"ABSENT"
Commissioner	**President**	**Leo M. Reinbold Commissioner**

Contractor

Snavely King Majoros O'Connor & Lee, Inc.
Name

1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**

Charles W. King	President
Typed Name	**Title**
Signature	July 17, 2001 **Date**

Agreement Information

Contract No.:	PU-427-01
Start Date:	7-11-01
End Date:	6-30-03
Program Title:	PU-399-01-186

Type of Contract:
(X) Cost Reimb.
( ) Fixed Price
( ) Unit Price
( ) Other

Budget Information

Cost Center:	7100
Services:	$7,579
Optional on-site review:	0
Expenses:	0
ID	52-0901220

Type of Contractor:
(X) Corporation
( ) Individual
( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two parties. This contract consists of this sheet, general provisions and specific provisions.

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet.

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the Commission.

The Contractor or the Commission may terminate this contract in whole or in part upon settlement or when both parties agree that the continuation of the contract would not produce results commensurate with further expenditures of funds. The two parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

In the event state or federal funds are reduced or terminated, the financial participation of the Commission may be reduced or terminated.

Disputes

The Contractor agrees to attempt to resolve disputes arising from this contract by administrative process and negotiations in lieu of litigation. Continued performance by the Contractor during disputes is assured.

Any dispute concerning a question of fact arising under this contract which is not settled by the informal means shall be decided by the authorized representative of the Commission who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the Contractor.

The Contractor shall be afforded an opportunity to be heard and to offer evidence in support of an appeal. Pending final decision of a dispute, the Contractor shall proceed diligently with the performance of the contract and in accordance with the decision of the Commission.

FISCAL RESPONSIBILITIES

Records

The Contractor agrees to maintain program records required by the Commission and to produce program narrative and statistical data at times prescribed by the Commission.

The Contractor agrees to maintain and retain all books, records, and other documents required by the Commission relevant to this agreement for four years after final payment. Records shall be retained beyond four years if audit findings have not been resolved.

No Claim for Additional Work

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the Commission.

Time Keeping Procedures

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

Monitoring, Evaluation and Audit

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the Commission, or their designees who shall have full access to and the right to examine all books, records and other relevant documents.

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PROGRAM REQUIREMENTS

Equal Opportunity

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
July 11, 2001

Purpose

The Commission staff has initiated an investigation into the North Dakota earnings of Montana-Dakota Utilities Co.'s electric operations. To fully pursue and represent its case, staff requires assistance to determine MDU's appropriate cost of capital. The contractor will determine the appropriate cost of capital for MDU in sufficient detail as is necessary to attest to what constitutes a fair and reasonable rate of return.

The contractor's proposal included a bid of $15,579. Due to budgetary constraints, the commission was unable to enter into an agreement for the entire bid amount initially. Instead, the commission entered into a contract for $8,000 on May 17, 2001. Using the same bid proposal, it is the commission's intent to enter into a second contract for any additional work necessary, not to exceed $7,579. All work under this contract must be completed prior to June 30, 2003. All claims for reimbursement under this contract shall be submitted by June 30, 2003.

The specific purpose is to investigate, analyze and provide testimony proposing the proper cost of capital and capital structure necessary to yield the opportunity for MDU to earn a fair and reasonable return on its investment in electric operations in North Dakota including:

1. Professional analysis and review of filing.
2. Prepare and conduct discovery as necessary.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff and staff legal counsel updated.
4. Prepare written testimony and provide and advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to pre-filed testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports. Final payment will be made upon satisfactory completion of the described project work, as determined by the commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

July 11, 2001

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Suite 410
Washington D C 20005

Dear Mr. King:

Enclosed is Contract No. PU-427-01 for consulting services in Case No. PU-399-01-186. Please sign both copies of the contract, keep one copy for your files and return one copy to me.

When submitting invoices for payment, **please send them directly to me** and identify the case number for each invoiced amount.

If you have any questions, please call me at 701-328-4079.

Sincerely,

Mike Diller
Director of Accounting

Enclosures

12 **PU-399-01-186** Pages: 1

Letter to consultant re Contract

by Public Service Commission

07/11/2001 CC: Comm Legal Illona, Pat, Jerry Mike .

APPROVED
DATE: 7-11-01
KME

MOTION

July 11, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission execute a $7,579 contract with Snavely King Majoros O'Connor & Lee, Inc. for consulting services in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

MRD

11 **PU-399-01-186** Pages: 1

Motion to execute contract to Snavely King Majoros O'Connor & Lee Inc by Public Service Commission

07/11/2001 CC. Comm Legal Illona, Pat, Jerry Mike .

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: July 11, 2001

Anthony T. Clark	Susan E. Wefald	"ABSENT" Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor		
Snavely King Majoros O'Connor & Lee, Inc.		
Name		
1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**
Charles W. King		President
Typed Name		**Title**
Signature		**Date**

Agreement Information

Contract No.: PU-427-01
Start Date: 7-11-01
End Date: 6-30-03
Program Title: PU-399-01-186

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center: 7100
Services: $7,579
Optional on-site review: 0
Expenses: 0

ID 52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two parties. This contract consists of this sheet, general provisions and specific provisions.

Contract No. PU-427-01 issued to Snavely King Majoros O'Connor & Lee Inc by Public Service Commission

07/11/2001 CC: Comm Legal Illona, Pat, Jerry Mike

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

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The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

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The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

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No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
July 11, 2001

Purpose

The Commission staff has initiated an investigation into the North Dakota earnings of Montana-Dakota Utilities Co.'s electric operations. To fully pursue and represent its case, staff requires assistance to determine MDU's appropriate cost of capital. The contractor will determine the appropriate cost of capital for MDU in sufficient detail as is necessary to attest to what constitutes a fair and reasonable rate of return.

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1. Professional analysis and review of filing.
2. Prepare and conduct discovery as necessary.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff and staff legal counsel updated.
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5. Prepare written and oral testimony in rebuttal to pre-filed testimony of other parties in the proceeding.
6. Testify at the hearing.
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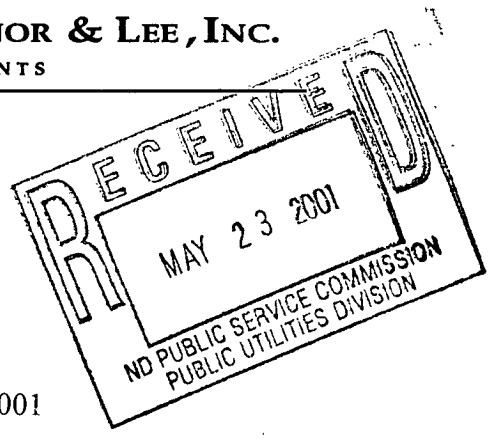
No part of this contract may be assigned, sublet or subcontracted.

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS



May 21, 2001

Sharon Helbling
Public Utilities Division
North Dakota Public Service Division
State Capitol 12th Floor
Bismarck, ND 58505-0480

Dear Ms. Helbling:

Enclosed herewith is a signed copy of Contract No. PU 425-01 for performing a cost of capital study of Montana-Dakota Utilities. I have retained one copy for our files.

Thank you very much for your attention to this matter.

Sincerely

Charles W. King

9 **PU-399-01-186** Pages: 6

Signed Contract No. PU-425-01
by Snavely King Majoros O'Connor & Lee, Inc.
05/23/2001 CC: Comm Legal Illona, Pat, Jerry Mike

1220 L STREET, NW, SUITE 410, WASHINGTON, DC 20005-(202)371-1111, FAX (202)842-4966

1471 CASTILLO DELMAR, CAROLINA, PR 00979-(809)783-7683, FAX(809)783-7559

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: May 17, 2001

Anthony T. Clark	Susan E. Wefald	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor

Snavely King Majoros O'Connor & Lee, Inc.
Name

1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**

Charles W. King	President
Typed Name	**Title**
Signature	May 21, 2001 **Date**

Agreement Information

Contract No.:	PU-425-01
Start Date:	5-17-01
End Date:	6-30-01
Program Title:	PU-399-01-186

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center:	7100
Services:	$8,000
Optional on-site review:	0
Expenses:	0
ID	52-0901220

Type of Contractor: ( ) Individual
(X) Corporation ( ) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other

This contract is entered into between the above two parties. This contract consists of this sheet, general provisions and specific provisions.

GENERAL PROVISIONS

CONTRACTUAL FEATURES

Legal Authority

The Contractor assures that it possesses legal authority to participate in this contract.

Assignment/Subcontracting

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet.

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract.

Termination

The Commission, by ten days written notice listing causes and reasons, may terminate this contract in whole or in part when it is determined that the Contractor has failed to meet the conditions of the contract. The Commission will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination.

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the Commission.

The Contractor or the Commission may terminate this contract in whole or in part upon settlement or when both parties agree that the continuation of the contract would not produce results commensurate with further expenditures of funds. The two parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

In the event state or federal funds are reduced or terminated, the financial participation of the Commission may be reduced or terminated.

Disputes

The Contractor agrees to attempt to resolve disputes arising from this contract by administrative process and negotiations in lieu of litigation. Continued performance by the Contractor during disputes is assured.

Any dispute concerning a question of fact arising under this contract which is not settled by the informal means shall be decided by the authorized representative of the Commission who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the Contractor.

The Contractor shall be afforded an opportunity to be heard and to offer evidence in support of an appeal. Pending final decision of a dispute, the Contractor shall proceed diligently with the performance of the contract and in accordance with the decision of the Commission.

FISCAL RESPONSIBILITIES

Records

The Contractor agrees to maintain program records required by the Commission and to produce program narrative and statistical data at times prescribed by the Commission.

The Contractor agrees to maintain and retain all books, records, and other documents required by the Commission relevant to this agreement for four years after final payment. Records shall be retained beyond four years if audit findings have not been resolved.

No Claim for Additional Work

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the Commission.

Time Keeping Procedures

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

Monitoring, Evaluation and Audit

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the Commission, or their designees who shall have full access to and the right to examine all books, records and other relevant documents.

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PROGRAM REQUIREMENTS

Equal Opportunity

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, disability, or political affiliation or belief.

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship.

Nondiscrimination

This contract and any subcontract hereunder is subject to the Age Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990.

Copyrights and Rights in Data

The contractor agrees that any plans, drawings, designs, specifications, computer programs (which are substantially paid for with federal grant or state funds), technical reports, operation manuals and other work submitted with a proposal or grant application or which are specified to be delivered under this contract or which are developed or produced and paid for under this contract (referred to in this clause as "subject data") are subject to the rights of the Commission to use, duplicate and disclose the subject data in whole or in part, in any manner for any purpose whatsoever, and have others do so. If the material is copyrightable, the contractor may copyright the material, subject to the rights in the government, but the Commission reserves a royalty-free, non-exclusive and irrevocable license to reproduce, publish and use the material, in whole or in part, and to authorize others to do so. The contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts expected to produce copyrightable "subject data."

SPECIFIC PROVISIONS
May 17, 2001

Purpose

The Commission staff has initiated an investigation into the North Dakota earnings of Montana-Dakota Utilities Co.'s electric operations. To fully pursue and represent its case, staff requires assistance to determine MDU's appropriate cost of capital. The contractor will determine the appropriate cost of capital for MDU in sufficient detail as is necessary to attest to what constitutes a fair and reasonable rate of return.

The contractor's proposal included a bid of $15,579. Due to budgetary constraints, the commission is unable to enter into an agreement for the entire bid amount at this time. Instead, this contract requires that the contractor cease working once total costs incurred total $8,000. All work under this contract must be completed prior to June 30, 2001. All claims for reimbursement under this contract shall be submitted by June 30, 2001. It is the commission's intent to enter into a second contract after July 1, 2001 for any additional work necessary, not to exceed $7,579.

The specific purpose is to investigate, analyze and provide testimony proposing the proper cost of capital and capital structure necessary to yield the opportunity for MDU to earn a fair and reasonable return on its investment in electric operations in North Dakota including:

1. Professional analysis and review of filing.
2. Prepare and conduct discovery as necessary.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff and staff legal counsel updated.
4. Prepare written testimony and provide and advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to pre-filed testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports. Final payment will be made upon satisfactory completion of the described project work, as determined by the commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

CONFLICT OF INTEREST

DISCLAIMER

The undersigned does hereby certify there is no financial substantive interest in the utilities which are or may be parties in this proceeding. It is also certified that no business officer, partner, employee, agent, or any immediate family member has a substantive financial interest in the utilities which are or may be parties in this proceeding. It is further certified that, should a financial interest occur during the period of active involvement in the proceedings, the Commission will be immediately notified and shall have the right to terminate the contract.

Signature

Date May 21, 2001

President
Title

Swanson King Majoros O'Connor & Lee, Inc
Company Name

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 17, 2001

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Ste 410
Washington D C 20005

Dear Mr. King:

Enclosed is Contract No. PU-425-01 for consulting services in Case No. PU-399-01-186. Please sign both copies of the contract, keep one copy for your files and return one copy to me.

When submitting invoices for payment, **please send them directly to Mike Diller,** and identify the case number(s) for each invoiced amount.

If you have any questions, you can call Mike at 701-328-4079.

Sincerely,

Sharon Helbling
Public Utilities Division

sdh

Enclosures

8 **PU-399-01-186** Pages: 1

Cover letter re contract for consulting services
by Public Service Commission

05/17/2001

APPROVED

DATE: 5-17-01
Kmt

MOTION

May 17, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission appoint Mike Diller and Bill Binek as advocacy staff in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

Sdh

7 **PU-399-01-186** Pages: 1

Motion appointing Diller & Binek as advocacy staff
by Public Service Commission

05/17/2001

APPROVED
DATE: 5-17-01
KMF

MOTION

May 17, 2001

Montana-Dakota Utilities Co.
2000 Electric Operations
Annual Report

Case No. PU-399-01-186

I move the Commission execute an $8,000 contract with Snavely King Majoros O'Connor & Lee, Inc. for consulting services in Montana-Dakota Utilities Co.'s 2000 Electric Operations Annual Report investigation, Case No. PU-399-01-186.

MRD

6 **PU-399-01-186** Pages: 1

Mtn approved to execute an $8000 contract w/Snavely King Majoros by Public Service Commission

05/17/2001

CONTRACT

Administrator: Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505-0480
(701) 328-2400

Date: May 17, 2001

Anthony T. Clark	Susan E. Wefald	Leo M. Reinbold
Commissioner	**President**	**Commissioner**

Contractor		
Snavely King Majoros O'Connor & Lee, Inc.		
Name		
1220 L St NW Ste 410	Washington D C 20005	202-371-9156
Address	**City/State/Zip**	**Phone**
Charles W. King		President
Typed Name		**Title**
Signature		**Date**

Agreement Information

Contract No.: PU-425-01

Start Date: 5-17-01

End Date: 6-30-01

Program Title: PU-399-01-186

Type of Contract: ( ) Fixed Price
(X) Cost Reimb. ( ) Unit Price
( ) Other

Budget Information

Cost Center: 7100

Services: $8,000

Optional on-site review: 0

Expenses: 0

ID 52-0901220

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(X) Corporation ( ) Partnership
( ) Public Agency
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May 17, 2001

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1. Professional analysis and review of filing.
2. Prepare and conduct discovery as necessary.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff and staff legal counsel updated.
4. Prepare written testimony and provide and advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to pre-filed testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

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In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
2000-Electric Operations
Annual Report

Case No. PU-399-01-186

Montana-Dakota Utilities Co.
2000-Gas Operations
Annual Report

Case No. PU-399-01-187

AFFIDAVIT OF SERVICE BY ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **4th day of May 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with first class postage fully prepaid, securely sealed :

Staff Recommendations on 2000 Annual Reports

The envelope was addressed as follows:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **4th day of May, 2001**.

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

SEAL

Sandra L Scott
Notary Public

Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E. Wefald, President
Leo M. Reinbold
Anthony T. Clark

Executive Secretary
Jon H. Mielke

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
web: www.psc.state.nd.us
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 4, 2001

Don Ball
Director of Regulatory Affairs
Montana-Dakota Utilities Co.
400 N Fourth St
Bismarck, ND 58501

Don,

Enclosed is a memo to the commission that recommends that your 2000 annual report for gas service in North Dakota be closed without investigation. It also suggests that the commission close its investigation of 1999 electric earnings and file a complaint case against MDU because its electric rates are too high. Staff's case will then be pursued through the 2000 electric report. In accordance with commission policy, staff is providing a copy of its recommendation in the event your company would like to respond to the memo and staff's conclusion.

Sincerely,

Mike Diller
Director of Accounting

3 **PU-399-01-186** Pages: 1

Letter to MDU re annual report

by Public Service Commission by Mike Diller

05/04/2001

Memorandum

To: Commissioners
Jon Mielke
Illona Jeffcoat-Sacco

From: Mike Diller

Date: May 4, 2000

Re: **2000 Reported Returns on Equity**
Admin Agenda Item for May 9

As you can see from the attached chart, two out of seven rate of return regulated utilities reported earnings on equity greater than 12% for the year ended 2000. Of these two, Otter Tail's electric operation reported a slightly higher return of 12.91% and is currently operating under a performance-based ratemaking plan. Great Plain's has not reported yet but staff does not expect reported earnings to exceed 12% given recent earnings levels and the closure of the ProGold plant during 2000.

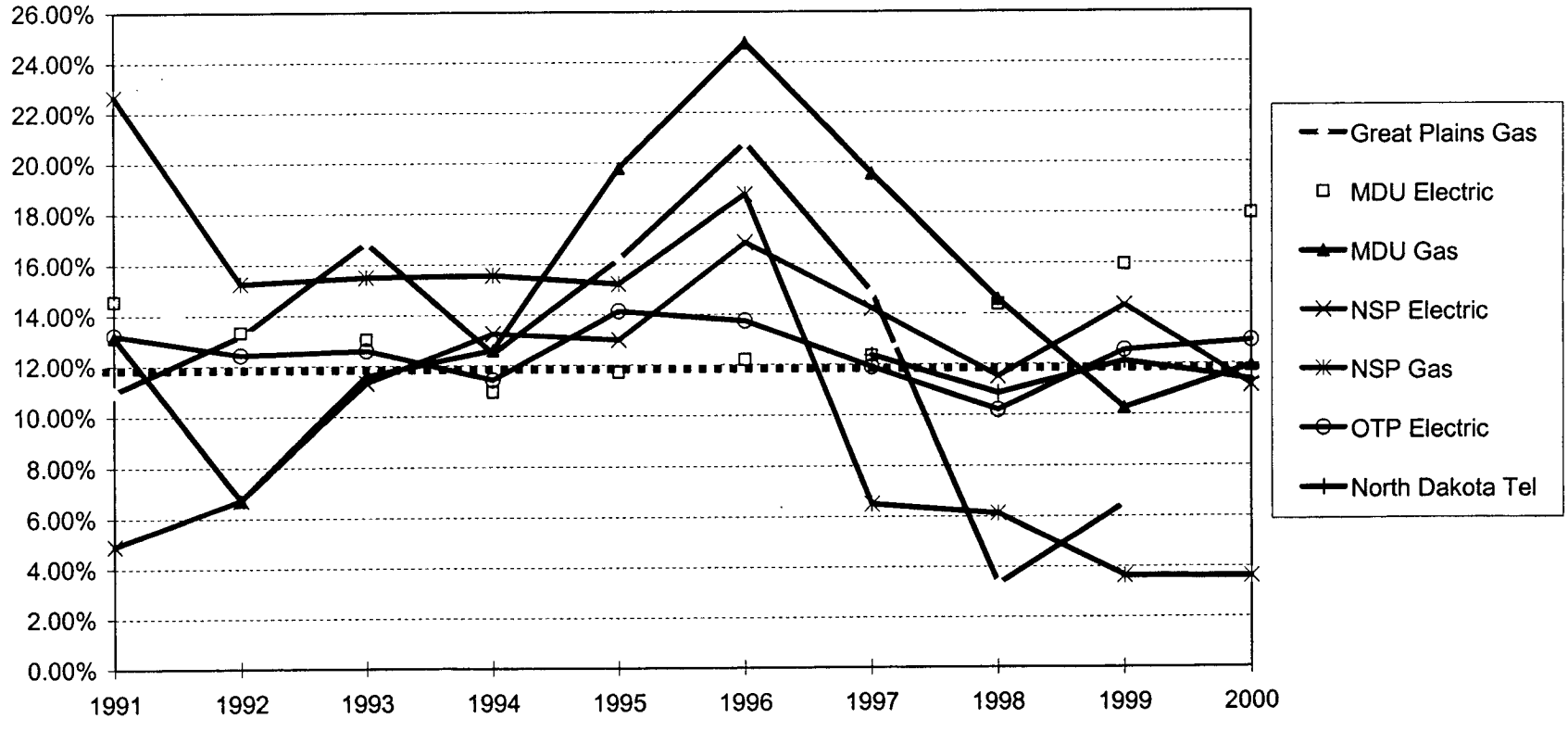
You will note that MDU's electric operations reported a return on equity of 17.95%. Like 1999, MDU's electric operation reported the highest earnings. Further, MDU's electric operations have reported earnings above 12% for the last five years.

Staff recommends that the annual reports be closed for all gas and electric operations except for MDU's electric operation. Staff also recommends that MDU's 1999 annual report for electric operations be closed. The 2000 annual report and the information gathered by staff relating to 1999 will be used to file a complaint against MDU alleging that its electric rates are too high.

In accordance with commission policy, this memo has been copied to all rate of return regulated companies for purposes of responding. Any responses to this memo will be docketed in the annual report case and distributed to commissioners and applicable staff members.

North Dakota
Investor Owned Gas & Electric Utilities
Reported Returns on Equity

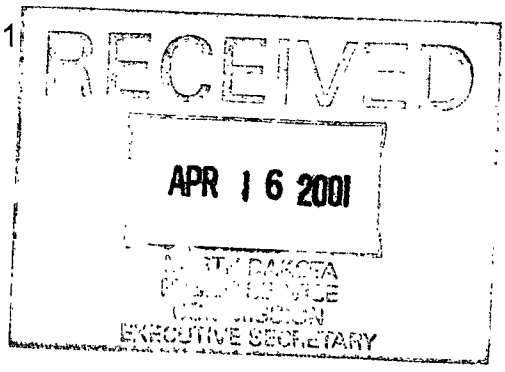
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Last 3 Year Average	10 Year Average
Great Plains Gas	10.95%	13.17%	16.84%	12.44%	16.17%	20.77%	14.83%	3.31%	6.50%	No Report	4.91%	12.78%
MDU Electric	14.56%	13.33%	13.04%	10.96%	11.72%	12.19%	12.35%	14.37%	15.94%	17.95%	16.09%	13.64%
MDU Gas	13.14%	6.71%	11.58%	12.59%	19.78%	24.75%	19.55%	14.55%	10.25%	11.92%	12.24%	14.48%
North Dakota Tel							12.35%	10.85%	12.10%	11.36%	11.44%	11.67%
NSP Electric	4.90%	6.71%	11.31%	13.25%	12.98%	16.82%	14.20%	11.50%	14.30%	11.15%	12.32%	11.71%
NSP Gas	22.64%	15.24%	15.48%	15.55%	15.19%	18.73%	6.48%	6.12%	3.64%	3.61%	4.46%	12.27%
OTP Electric	13.21%	12.42%	12.59%	11.41%	14.11%	13.72%	11.88%	10.18%	12.53%	12.91%	11.87%	12.50%
Average	13.23%	11.26%	13.47%	12.70%	14.99%	17.83%	13.09%	10.13%	10.75%	11.48%	10.79%	12.89%



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

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

April 16, 2001



Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Annual Reports

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., herewith submits one copy of its Electric and Gas Annual Reports for the year ended December 31, 2000 consisting of:

North Dakota Electric and Gas Annual Reports
North Dakota Electric and Gas Cost of Service Studies
2000 Annual Report to Stockholders
Report of Independent Public Accountants

A copy of the FERC Form No. 1 is not available at this time. We expect to have it by May 1 and will forward a copy to you at that time.

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

Sincerely,

Donald R. Ball
Director of Regulatory Affairs

Enclosures

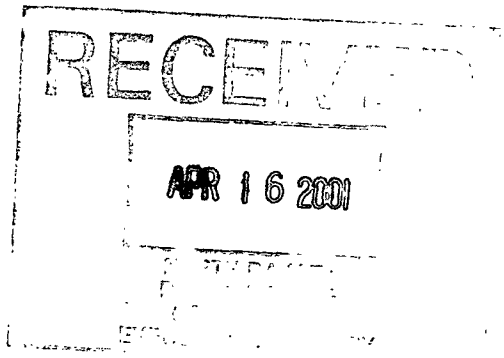
1 **PU-399-01-186** Pages: 12

Report

by Montana-Dakota Utilities Co., a Division of MDU R

04/16/2001

ARTHUR ANDERSEN



Report of independent public accountants

To the managing committee of
Montana-Dakota Utilities Co.:

We have audited the monthly filings of Montana-Dakota Utilities Co. (the Company) which support automatic adjustment clause calculations for the year ended December 31, 2000, for conformity, in all material respects, with the financial procedural aspects of the automatic adjustment clause calculations of the North Dakota Public Service Commission as set forth in Chapter 69-09-01-30 of the North Dakota Administrative Code. Our audit for this purpose was made in accordance with auditing standards generally accepted in the United States and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

These filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to the fair determination of the automatic adjustment clause calculations within the monthly filings and whether those rates have been properly applied to customer bills based on our audit. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the Company has fairly determined the automatic adjustment clause calculations for the year ended December 31, 2000, in accordance with the financial procedural aspects of the automatic adjustment clause calculations, as set forth in Chapter 69-09-01-30 of the North Dakota Administrative Code, and has properly applied the automatic adjustment clause calculations to customer bills.

This report is intended solely for the information and use of the managing committee of the Company and the North Dakota Public Service Commission and should not be used for any other purposes.

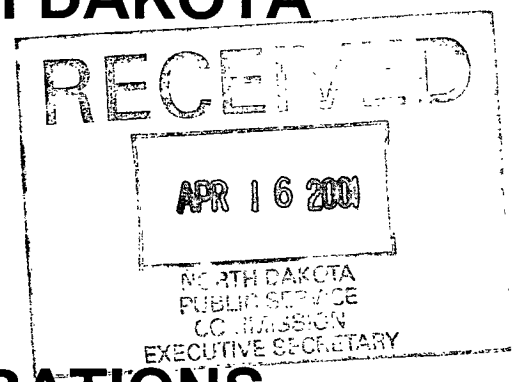
Arthur Andersen LLP

Arthur Andersen LLP

Minneapolis, Minnesota,
February 23, 2001

ANNUAL REPORT

STATE OF NORTH DAKOTA



ELECTRIC OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2000

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

INDEX

I. Intrastate Return on Equity
II. Capital Structure
III. Affiliated Transactions
IV. Miscellaneous Statistics

MONTANA-DAKOTA UTILITIES CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Line #	Description	(A) 2000 Total Company	(B) 2000 North Dakota	(C) ND % (B / A)	(D) 1999 North Dakota	(E) Variance (B-D / D)
	Operating Revenues:					
1	Residential	$55,456,111	$31,916,164	57.55%	$32,098,609	-0.57%
2	Small General 1/	28,908,948	17,274,733	59.76%	17,170,278	0.61%
3	Large General 1/	45,053,453	26,840,103	59.57%	26,667,027	0.65%
4	Lighting Service 1/	2,537,881	1,419,532	55.93%	1,451,315	-2.19%
5	Municipal Pumping Service	1,602,288	1,140,575	71.18%	1,179,802	-3.32%
6	Cogeneration	17	17	100.00%	13	30.77%
7	Sales for Resale	22,624,924	15,034,366	66.45%	13,265,193	13.34%
8	Other Operating Revenues	4,476,480	2,690,908	60.11%	2,373,005	13.40%
9	Unbilled Revenue	960,968	646,587	67.28%	(282,946)	-328.52%
10	Total Operating Revenues	$161,621,070	$96,962,985	59.99%	$93,922,296	3.24%
	Operating Expenses:					
11	Production Expense	$66,762,602	$38,363,986	57.46%	$37,160,223	3.24%
12	Transmission Expense	5,252,098	3,566,914	67.91%	3,667,049	-2.73%
13	Distribution Expense	8,027,633	4,660,253	58.05%	4,585,754	1.62%
14	Customer Accounts Expense	3,666,028	2,113,265	57.64%	2,161,677	-2.24%
15	Customer Service & Info. Exp.	158,607	105,193	66.32%	96,288	9.25%
16	Sales Expense	442,462	269,310	60.87%	258,276	4.27%
17	Administration & General Exp.	12,354,751	8,154,363	66.00%	8,303,279	-1.79%
18	Depreciation Expense	19,115,072	11,803,207	61.75%	11,436,109	3.21%
19	Taxes Other than Income	7,098,538	3,810,138	53.67%	3,935,303	-3.18%
20	Total Operating Expenses	$122,877,791	$72,846,629	59.28%	$71,603,958	1.74%
21	Net Operating Income					
22	before Income Taxes	$38,743,279	$24,116,356	62.25%	$22,318,338	8.06%
	Income Tax Expense:					
23	Investment Tax Credits					
24	Deferred Income Taxes	($1,131,336)	($713,525)	63.07%	($431,764)	65.26%
25	Income Taxes	12,193,160	7,464,076	61.22%	6,750,792	10.57%
26	Total Income Tax Expense	$11,061,824	$6,750,551	61.03%	$6,319,028	6.83%
27	**Net Regulated Earnings**	$27,681,455	$17,365,805	62.73%	$15,999,310	8.54%

1/ The North Dakota contract revenue delta associated with these classes is shown below. The contract revenue delta is the difference between the revenue collected under all special contracts and the revenue that would have been collected had these loads been charged the standard rate.

	2000	1999
Small General	$3,005	$7,181
Large General	718,952	693,348
Lighting	12	12
Total	$721,969	$700,541

MONTANA-DAKOTA UTILITIES CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Line #	Description	(A) 2000 Total Company	(B) 2000 North Dakota	(C) ND % (B / A)	(D) 1999 North Dakota	(E) Variance (B-D / D)
	Rate Base:					
1	Plant in Service	$584,334,045	$375,346,966	64.23%	$366,890,181	2.30%
2	Less: Accumulated Depreciation	315,962,676	202,070,983	63.95%	193,286,203	4.54%
3	Add: Construct. Work in Prog. 1/	1,426,000	849,510	59.57%	2,572,074	-66.97%
4	Net Plant in Service	$269,797,369	$174,125,493	64.54%	$176,176,052	-1.16%
	Additions: 2/					
5	Materials and Supplies	$5,018,321	$3,201,940	63.81%	$3,252,339	-1.55%
6	Fuel Stocks	1,921,312	1,276,665	66.45%	1,191,716	7.13%
7	Prepayments	323,197	209,129	64.71%	265,379	-21.20%
8	Total Additions	$7,262,830	$4,687,734	64.54%	$4,709,434	-0.46%
	Deductions:					
9	Accum. Deferred Income Taxes	$61,607,073	$41,563,881	67.47%	$42,124,430	-1.33%
10	Accumulated Deferred ITC's	4,041,281	3,073,534	76.05%	3,583,108	-14.22%
11	Cust. Advances for Construct. 2/	1,571,681	508,596	32.36%	309,378	64.39%
12	Total Deductions	$67,220,035	$45,146,011	67.16%	$46,016,916	-1.89%
13	**Average Rate Base**	$209,840,164	$133,667,216	63.70%	$134,868,570	-0.89%
14	Rate of Return on Avg. Rate Base	13.192%	12.992%		11.863%	
15	Less: Weighted Cost of LTD	4.737%	4.737%		4.931%	
16	Weighted Cost of Pref. Stock	0.222%	0.222%		0.194%	
17	Weighted Return on Equity	8.233%	8.033%		6.738%	
18	% of Equity to Capital Structure	44.756%	44.756%		42.269%	
19	**Return on Equity**	18.395%	17.948%		15.941%	
20	**Return on Equity - Average**					
21	**Pool Sales 3/**	15.580%	15.008%		12.484%	

1/ Completed construction at December 31, 2000 not yet classified.
2/ Thirteen month average.
3/ Reflects historical five year average pool sales margins.

MONTANA-DAKOTA UTILITIES CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Line #	Description	(A) Balance @ Year End (000's)	(B) Ratio	(C) Cost	(D) Weighted Cost
1	Long-Term Debt 1/	$173,894	50.456%	9.388%	4.737%
2	Preferred Equity	16,500	4.788%	4.632%	0.222%
3	Common Equity	154,250	44.756%	2/	2/
4	Total	$344,644	100.000%		2/

1/ Balance includes a $40.0 million borrowing against a revolving credit and term loan agreement.
2/ Return on equity is calculated in Section I, page 2 of 2.

MONTANA-DAKOTA UTILITIES CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION
MAJOR TRANSACTIONS

Line #	Affiliate's Name	General Description of Service Rendered and/or Supplied	(Expense) &/or Revenue Total Company	Allocated to North Dakota
1	Knife River Corporation	**2000 Coal Purchases:**	($13,835,794)	($9,193,949)

Location	Tons	Amount	Cost/Ton
Heskett Plant	447,228	$4,411,201	$9.86
Lewis & Clark Plant	317,272	3,243,490	10.22
Coyote Plant (25%)	567,918	6,181,103	10.88
Total	1,332,418	$13,835,794	$10.38

		2000 Electric Sales:	$1,546,841	$1,431,143

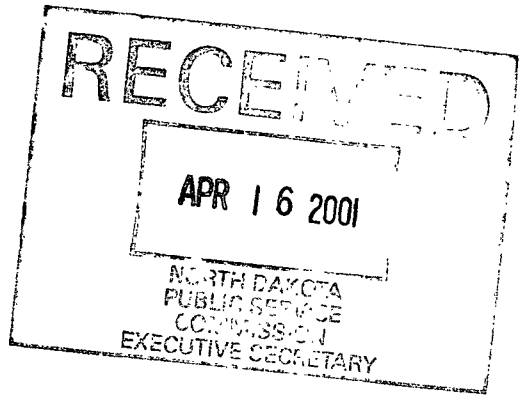
Location	Kwh Consump.	Amount
Beulah Mine - ND	24,576,200	$1,398,005
Gascoyne Mine - ND	295,800	18,715
Savage Mine - MT	2,215,500	115,698
Bismarck Office	235,360	14,423
Total	27,322,860	$1,546,841

2	Williston Basin Interstate Pipeline Company	2000 Natural Gas Purchases/Transportation	($47,939,358)	($19,517,771)
		WBI Refunds / Adjustments - Net	$12,150,517	$5,063,177
		2000 Dividend Income on Preferred Stock of WBI	$195,385	$108,718
3	Prairielands Energy Marketing, Inc.	2000 Natural Gas Purchases/Transportation	($353,369)	($172,753)
		2000 Natural Gas for Gas Turbine Generators and Lewis & Clark Station	($396,819)	($263,688)
4	Sage Gas Alliance LLC	2000 Natural Gas Purchases/Transportation	($11,747,774)	($4,882,119)

MONTANA-DAKOTA UTILITIES CO.
ANNUAL REPORT
TO THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Line #	Description		2000	1999 1/	1998 1/	1997 1/	1996 1/
	Customer Related						
1	Year End Customers	- Residential	58,844	60,975	60,449	60,376	59,730
2		- Small General	10,053	11,016	10,789	10,792	10,503
3		- Large General	696	788	706	690	658
4		- Lighting Service	384	3,362	3,471	3,341 2/	2,872
5		- Municipal Pumping	304	352	322	323	314
6		- Cogeneration	1	0	1	1	
7		- Total	70,282	76,493	75,738	75,523	74,077
8	Kwh's Sold	- Residential	474,136,337	469,760,676	470,310,160	479,049,480	483,447,629
9		- Small General	229,963,545	225,268,590	225,142,864	224,437,564	221,679,311
10		- Large General	502,683,823	489,557,866	471,261,026	465,249,381	464,653,903
11		- Lighting Service	24,419,149	24,561,414	24,425,636	24,061,789	24,124,536
12		- Municipal Pumping	25,342,527	25,496,314	26,342,191	28,336,271	26,214,565
		- Cogeneration	22	222			
13		- Total	1,256,545,403	1,234,645,082	1,217,481,877	1,221,134,485	1,220,119,944

1/ Customers for 1996 - 1999 reflect year end bills.
2/ The increase reflects changes in the number of accounts to accommodate the new Customer Information System but does not affect revenues or Kwh.



NORTH DAKOTA COST OF SERVICE STUDY

ELECTRIC OPERATIONS

2000

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
ELECTRIC UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2000

	Total Company	North Dakota	Others
Operating Revenues			
Sales Revenues			
Residential	$55,456,111	$31,916,164	$23,539,947
Small General	28,908,948	17,274,733	11,634,215
Large General	45,053,453	26,840,103	18,213,350
Lighting Service	2,537,881	1,419,532	1,118,349
Municipal Pumping Service	1,602,288	1,140,575	461,713
Cogeneration	17	17	
Sales for Resale	22,624,924	15,034,366	7,590,558
Unbilled Revenue	960,968	646,587	314,381
Total Sales Revenues	157,144,590	94,272,077	62,872,513
Other Operating Revenues	4,476,480	2,690,908	1,785,572
Total Operating Revenues	$161,621,070	$96,962,985	$64,658,085
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	$54,114,449	$29,573,957	$24,540,492
Production	12,648,153	8,790,029	3,858,124
Transmission	5,252,098	3,566,914	1,685,184
Distribution	8,027,633	4,660,253	3,367,380
Customer Accounts	3,666,028	2,113,265	1,552,763
Customer Service & Information	158,607	105,193	53,414
Sales	442,462	269,310	173,152
Administrative & General	12,354,751	8,154,363	4,200,388
Total O&M Expenses	96,664,181	57,233,284	39,430,897
Depreciation			
Production	8,516,437	5,438,022	3,078,415
Transmission	2,770,808	1,704,651	1,066,157
Distribution	4,632,730	2,634,057	1,998,673
General	562,319	350,532	211,787
Common	1,145,668	700,577	445,091
Amort. of Intangible Plant - General	303,861	194,773	109,088
Amort. of Intangible Plant - Common	768,989	492,286	276,703
Amort. of Acquisition Adjustment	414,260	288,309	125,951
Total Depreciation Expense	19,115,072	11,803,207	7,311,865

MONTANA-DAKOTA UTILITIES CO.
INCOME STATEMENT
ELECTRIC UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2000

	Total Company	North Dakota	Others
Operating Expenses Con't.			
Taxes Other Than Income Taxes			
Ad Valorem Taxes			
Production	1,336,111	929,882	406,229
Transmission	1,081,973	547,483	534,490
Distribution	1,855,186	750,807	1,104,379
General	152,646	60,284	92,362
Common - General	347,294	195,624	151,670
Common - Intangible	29,598	18,966	10,632
Total Ad Valorem Taxes	4,802,808	2,503,046	2,299,762
Other Taxes	2,295,730	1,307,092	988,638
Total Taxes Other Than Income Taxes	7,098,538	3,810,138	3,288,400
Current Income Taxes	12,193,160	7,464,076	4,729,084
Deferred Income Taxes	(1,131,336)	(713,525)	(417,811)
Total Operating Expenses	$133,939,615	$79,597,180	$54,342,435
Operating Income	$27,681,455	$17,365,805	$10,315,650
Year End Rate Base	$209,261,750	$132,981,026	$76,280,724
Rate of Return	13.23%	13.06%	13.52%

MONTANA-DAKOTA UTILITIES CO.
YEAR END RATE BASE
ELECTRIC UTILITY
TWELVE MONTHS ENDED DECEMBER 31, 2000

	Total Company	North Dakota	Others
Plant in Service			
Electric Plant in Service			
Steam Production	$245,814,735	$169,221,378	$76,593,357
Other Production	10,358,731	7,209,279	3,149,452
Total Production	256,173,466	176,430,657	79,742,809
Transmission	117,696,649	72,579,371	45,117,278
Distribution	147,255,792	85,983,891	61,271,901
General	17,649,531	10,388,036	7,261,495
Common	29,144,155	17,750,151	11,394,004
Intangible Plant - General	3,123,833	2,001,849	1,121,984
Intangible Plant - Common	8,410,901	5,384,436	3,026,465
Acquisition Adjustment	10,387,642	7,229,400	3,158,242
Total Electric Plant in Service	589,841,969	377,747,791	212,094,178
Accumulated Reserve for Depreciation			
Steam Production	147,349,762	98,696,626	48,653,136
Other Production	7,469,332	5,198,139	2,271,193
Total Production	154,819,094	103,894,765	50,924,329
Transmission	63,669,706	38,897,157	24,772,549
Distribution	73,279,411	43,156,500	30,122,911
General	8,898,955	5,378,432	3,520,523
Common	12,481,469	7,827,959	4,653,510
Intangible Plant - General	1,035,183	663,835	371,348
Intangible Plant - Common	2,379,031	1,522,993	856,038
Acquisition Adjustment	5,920,518	4,120,453	1,800,065
Total Accum. Reserve for Depreciation	322,483,367	205,462,094	117,021,273
Net Electric Plant in Service	267,358,602	172,285,697	95,072,905
CWIP in Service Pending Reclass.	1,426,000	849,510	576,490
Total Electric Plant in Service	$268,784,602	$173,135,207	$95,649,395
Additions			
Materials and Supplies	4,942,685	3,064,985	1,877,700
Fuel Stocks	1,640,603	1,090,202	550,401
Prepayments	184,035	120,643	63,392
Total Additions	6,767,323	4,275,830	2,491,493
Total Before Deductions	$275,551,925	$177,411,037	$98,140,888
Deductions			
Accumulated Deferred Income Taxes	61,052,948	41,099,069	19,953,879
Accumulated Investment Tax Credits	3,669,335	2,812,896	856,439
Customer Advances	1,567,892	518,046	1,049,846
Total Deductions	66,290,175	44,430,011	21,860,164
Year End Rate Base	$209,261,750	$132,981,026	$76,280,724

PM- 399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*: DARRELL PARKS — B. Date of Delivery: 11-26-01

C. Signature: X Darrell Parks — ☑ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☑ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*: 7099 3220 0002 8482 7757

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-00-M-0952

PM- 399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. PM
- Print your name and address on the reverse so that we can return the card to you. 25 NOV 2001
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*: [illegible] — B. Date of Delivery: 11-23-01

C. Signature: X [signature] — ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*: 7099 3220 0002 8482 7849

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-00-M-0952

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
MDU
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery
9-21-01

C. Signature
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7099 3220 0002 8481 1947

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

PU-399-01-186

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Don Ball
Montana-Dakota Utilities Co.
400 N 4th St
Bismarck ND 58501

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery
10-19-01

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)
7000 0520 0022 8655 3896

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952