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

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

January 18, 2013

Ms. Kate Whitney, Administrator
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

Re: General Gas Rate Application
Docket No. D2012.9.100

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Public Service Commission data request dated December 21, 2012. Responses to the following requests are attached:

PSC-014	PSC-025
PSC-015	PSC-026
PSC-016	PSC-027
PSC-017	PSC-028
PSC-018	PSC-029
PSC-019	PSC-030
PSC-020	PSC-031
PSC-021	PSC-032
PSC-022	PSC-039
PSC-023	PSC-040

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments
cc: Service List

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
DOCKET NO. D2012.9.100

PSC-014

Regarding: Statement A Current and Accrued Assets
Witness: Senger

The following questions should be referenced to the Current and Accrued Assets listed on Statement A page 3 of 4, MDU Resources Group, Inc. Nonconsolidated balance sheets June 30, 2011 and June 30, 2012

a. Break down the Customer Receivable account by MT, ND, SD and WY customers.

b. Please define "Other Accounts Receivable" and break down the account by MT, ND, SD and WY.

c. Please define "Accounts Receivable from Assoc. Companies" and break down the account by MT, ND, SD and WY.

d. What is the balance of Accounts Receivable by state as of November 30, 2012 for MT, SD, ND and WY?

e. Provide all work papers, analyses, memos and other documentation that support the above requests.

Response:

a.

Customer Receivables

	6/30/2011	6/30/2012
MT	$6,072,358	$3,544,872
ND	11,843,928	9,133,220
SD	3,363,735	1,547,186
WY	2,195,295	1,873,921
Other, including Great Plains	2,396,101	901,594
Customer Receivables	$25,871,417	$17,000,792

b. Other Accounts Receivables are miscellaneous receivables, such as a damage payments or non-utility work, which are not specifically associated with an individual state.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
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c. The Accounts Receivable from associated Companies is the amount related to receivables from subsidiary companies. The majority of this is related to the subsidiary's share of the MDU Resources Group, Inc. quarterly dividend paid July 1 of each year.

	6/30/2011	6/30/2012
Dividend from Subsidary companies	$23,729,000	$25,035,000

d.

Accounts Receivable balance at November 30, 2012

MT	$3,779,225
ND	8,589,499
SD	784,153
WY	1,678,625
Great Plains	1,003,730
Other	(16,321)
Customer Receivables	$15,818,912

e. Please see Attachment A.

Account Number	Account Description	6/30/12
1.1420	Sales Cust. Accounts Rec.	-11,281.44
11MT.1420	Sales Cust. Accounts Rec.	568,491.19
11WY.1420	Sales Cust. Accounts Rec.	1,855,016.70
12ER.1420	Sales Cust. Accounts Rec.	-902,854.96
12ND.1420	Sales Cust. Accounts Rec.	5,611,644.90
12SD.1420	Sales Cust. Accounts Rec.	1,425,488.73
13MT.1420	Sales Cust. Accounts Rec.	-49.42
13SD.1420	Sales Cust. Accounts Rec.	880,903.78
13WY.1420	Sales Cust. Accounts Rec.	61.72
15MT.1420	Sales Cust. Accounts Rec.	2,853,138.79
15ND.1420	Sales Cust. Accounts Rec.	3,384,365.86
15SD.1420	Sales Cust. Accounts Rec.	67,474.14
40MN.1420	Sales Cust. Accounts Rec.	777,296.18
40ND.1420	Sales Cust. Accounts Rec.	91,936.99
	Total Object Account 1420	16,601,633.16
11MT.1421	Transportation Acct. Rec.	42,498.59
11WY.1421	Transportation Acct. Rec.	-2,301.35
12ND.1421	Transportation Acct. Rec.	511.18
13SD.1421	Transportation Acct. Rec.	3,298.27
15MT.1421	Transportation Acct. Rec.	785.13
15ND.1421	Transportation Acct. Rec.	-98.17
	Total Object Account 1421	44,693.65
11WY.1422	Merch. Sales Acct. Rec.	353.78
12SD.1422	Merch. Sales Acct. Rec.	617.97
15MT.1422	Merch. Sales Acct. Rec.	325
	Total Object Account 1422	1,296.75
11MT.1423	Merch. Service Acct Rec.	42,644.69
11WY.1423	Merch. Service Acct Rec.	19,743.36
12ND.1423	Merch. Service Acct Rec.	91,034.81
12SD.1423	Merch. Service Acct Rec.	3,696.59
13MT.1423	Merch. Service Acct Rec.	34.8
13SD.1423	Merch. Service Acct Rec.	67,603.49
13WY.1423	Merch. Service Acct Rec.	1,313.88
15MT.1423	Merch. Service Acct Rec.	33,426.95
15ND.1423	Merch. Service Acct Rec.	38,672.27
15SD.1423	Merch. Service Acct Rec.	516.36

Account Number	Account Description	6/30/11
1.1420	Sales Cust. Accounts Rec.	-14,747.65
11MT.1420	Sales Cust. Accounts Rec.	2,243,219.96
11WY.1420	Sales Cust. Accounts Rec.	2,163,909.16
12ER.1420	Sales Cust. Accounts Rec.	-689,140.90
12ND.1420	Sales Cust. Accounts Rec.	6,826,881.36
12SD.1420	Sales Cust. Accounts Rec.	1,407,298.08
13MT.1420	Sales Cust. Accounts Rec.	104.52
13SD.1420	Sales Cust. Accounts Rec.	2,464,191.34
13WY.1420	Sales Cust. Accounts Rec.	216.29
15MT.1420	Sales Cust. Accounts Rec.	3,661,475.15
15ND.1420	Sales Cust. Accounts Rec.	4,756,899.32
15SD.1420	Sales Cust. Accounts Rec.	71,968.13
40MN.1420	Sales Cust. Accounts Rec.	2,136,995.65
40ND.1420	Sales Cust. Accounts Rec.	229,875.57
	Total Object Account 1420	25,259,145.98
11MT.1421	Transportation Acct. Rec.	36.12
11WY.1421	Transportation Acct. Rec.	1,266.97
12ND.1421	Transportation Acct. Rec.	-22,441.30
13SD.1421	Transportation Acct. Rec.	11,675.81
13WY.1421	Transportation Acct. Rec.	
15MT.1421	Transportation Acct. Rec.	9,040.31
15ND.1421	Transportation Acct. Rec.	-1,208.79
	Total Object Account 1421	-1,630.88
11MT.1422	Merch. Sales Acct. Rec.	-18.38
11WY.1422	Merch. Sales Acct. Rec.	363.78
12ND.1422	Merch. Sales Acct. Rec.	1,133.11
12SD.1422	Merch. Sales Acct. Rec.	671.19
13SD.1422	Merch. Sales Acct. Rec.	681.46
15MT.1422	Merch. Sales Acct. Rec.	-673.45
15ND.1422	Merch. Sales Acct. Rec.	105
	Total Object Account 1422	2,262.71
11MT.1423	Merch. Service Acct Rec.	50,668.48
11WY.1423	Merch. Service Acct Rec.	23,319.13
12ND.1423	Merch. Service Acct Rec.	84,791.61
12SD.1423	Merch. Service Acct Rec.	5,485.99
13SD.1423	Merch. Service Acct Rec.	79,413.01

Account Number	Account Description	6/30/12
40MN.1423	Merch. Service Acct Rec.	27,665.15
40ND.1423	Merch. Service Acct Rec.	5,749.30
	Total Object Account 1423	332,101.65
11MT.1424	Misc. Accounts Receivable	188.47
11WY.1424	Misc. Accounts Receivable	-267.52
12ER.1424	Misc. Accounts Receivable	121,038.22
12ND.1424	Misc. Accounts Receivable	-31,028.68
12SD.1424	Misc. Accounts Receivable	-87,955.12
13SD.1424	Misc. Accounts Receivable	-32,641.46
15MT.1424	Misc. Accounts Receivable	3,387.95
15ND.1424	Misc. Accounts Receivable	38,117.38
40MN.1424	Misc. Accounts Receivable	10,507.36
40ND.1424	Misc. Accounts Receivable	-279.65
	Total Object Account 1424	21,066.95

Account Number	Account Description	6/30/11
15MT.1423	Merch. Service Acct Rec.	54,154.88
15ND.1423	Merch. Service Acct Rec.	85,959.30
15SD.1423	Merch. Service Acct Rec.	170.16
40MN.1423	Merch. Service Acct Rec.	31,896.77
40ND.1423	Merch. Service Acct Rec.	5,799.81
	Total Object Account 1423	421,659.14
11MT.1424	Misc. Accounts Receivable	10,405.05
11WY.1424	Misc. Accounts Receivable	6,219.74
12ER.1424	Misc. Accounts Receivable	118,084.98
12ND.1424	Misc. Accounts Receivable	61,786.62
12SD.1424	Misc. Accounts Receivable	-83,541.59
13SD.1424	Misc. Accounts Receivable	-23,222.81
15MT.1424	Misc. Accounts Receivable	43,945.45
15ND.1424	Misc. Accounts Receivable	50,021.85
15SD.1424	Misc. Accounts Receivable	
40MN.1424	Misc. Accounts Receivable	6,571.03
40ND.1424	Misc. Accounts Receivable	-290.17
	Total Object Account 1424	189,980.15

	6/30/12		6/30/11
MT	3,544,872.14	MT	6,072,358.09
ND	9,133,219.55	ND	11,843,928.08
SD	1,547,186.01	SD	3,363,734.85
WY	1,873,920.57	WY	2,195,295.07
Great Plains	912,875.33	Great Plains	2,410,848.66
Other	-11,281.44	Other	-14,747.65
Customer Receivables	17,000,792.16	Customer Receivables	25,871,417.10

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
DOCKET NO. D2012.9.100

PSC-015

Regarding: Statement A Current and Accrued Assets
Witness: Senger

Please explain the increase of the "Special Deposits" account listed on Statement A page 3 of 4, MDU Resources Group, Inc. Nonconsolidated balance sheets June 30, 2011 and June 30, 2012 from 2011 through 2012.

Response:

The total change is $250,215, where $245,635 of the total increase relates to a deposit with the Midwest Independent Transmission System Operator (MISO) for the plant interconnection at the Heskett 3 natural gas combustion turbine plant.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
DOCKET NO. D2012.9.100

PSC-016

Regarding: Statement A Current and Accrued Assets
Witness: Senger

Please explain the increase of the "Miscellaneous Current and Accrued Assets" account listed on Statement A page 3 of 4, MDU Resources Group, Inc. Nonconsolidated balance sheets June 30, 2011 and June 30, 2012 from 2011 through 2012.

Response:

The entire balance as of June 2012 is related to the pricing of gas withdrawn and replaced from storage. During the heating season, gas is withdrawn from storage and priced at the estimated gas commodity cost for the injection season, usually the summer months of May through September. The difference between the cost of the gas in storage and the estimated price of gas is recorded in the replacement reserve. When gas is purchased and replaced in storage during the summer months, the amounts are reversed and when all of the gas is replaced the asset account is reduced to zero.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED DECEMBER 21, 2012
DOCKET NO. D2012.9.100

PSC-017

Regarding: Rate Decisions
Witness: Applicable Witness

Please provide a list of all rate decisions for all divisions and subsidiaries of MDU issued since January 1, 2010.

Response:

Please see Attachment A for copies of all rate decisions for Montana-Dakota issued since January 1, 2010.

Response No. PSC-017
Attachment A

Service Date: August 2, 2011

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority To Establish Increased Rates for Electric Service	)	REGULATORY DIVISION DOCKET NO. D2010.8.82 ORDER NO. 7115d
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	)	REGULATORY DIVISION DOCKET NO. D2008.5.53 ORDER NO. 7010a
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	)	REGULATORY DIVISION DOCKET NO. D2009.6.87 ORDER NO. 7011a
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	)	REGULATORY DIVISION DOCKET NO. D2009.12.153 ORDER NO. 7055a
IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	)	REGULATORY DIVISION DOCKET NO. D2010.6.66 ORDER NO. 7094a
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	)	REGULATORY DIVISION DOCKET NO. D2010.11.109 ORDER NO. 7125a

FINAL ORDER

<u>Appearances</u>

<u>For the Applicant:</u>

John Alke, Attorney at Law, Hughes, Kellner, Sullivan & Alke, PLLP, 40 W. Lawrence, Suite A, Helena, Montana, 59624

For the Intervenors:

Mary Wright, Attorney at Law, Montana Consumer Counsel, 111 North Last Chance Gulch Suite 1B, Helena, Montana, 59620-1703

Thorvald A. Nelson, Attorney at Law, Holland & Hart, 8390 East Crescent Parkway, Suite 400, Greenwood Village, Colorado 80111, on behalf of Encore Operating LP, ConocoPhillips, and Burlington Resources

Before:

Travis Kavulla, Chairman
Gail Gutsche, Vice Chair
W.A. (Bill) Gallagher, Commissioner
Brad Molnar, Commissioner
John Vincent, Commissioner

Commission Staff:

Leroy Beeby, Rate Analyst
Eric Eck, Revenue Requirements Bureau Chief
Scott Fabel, Rate Analyst
Sarah Norcott, Attorney, Legal Division
James C. Paine, Attorney, Legal Division
Will Rosquist, Rate Design Bureau Chief

Procedural History

1. On August 12, 2010, Montana-Dakota Utilities Co. (MDU) filed with the Montana Public Service Commission (Commission or PSC) an application for authority to increase its electric service rates in Montana by $5,502,341. MDU proposed that the increase be recovered from its customers by increasing annual customer class rates as follows: Residential rates by $1,869,589 (a 14.5 percent increase), Small General Service rates by $1,016,434 (a 13 percent increase), Large General Service rates by $2,492,644 (a 12.3 percent increase), Municipal Pumping rates by $55,297 (a 14.5 percent increase), and Lighting rates by $68,377 (an 8.6 percent increase).

2. Concurrent with its general electric rate increase application, MDU requested an interim increase in electric revenues of $3,125,808. MDU's interim request represented a uniform percentage rate increase of 7.43 percent.

3. On August 18, 2010, the Commission issued a Notice of Application and Intervention Deadline. Encore Operating LP, ConocoPhillips, and Burlington Resources (collectively

referred to as Encore) and Montana Consumer Counsel (MCC) petitioned for and were granted intervention.

4. The Commission issued Procedural Order No. 7115 on October 8, 2011.

5. On December 3, 2010, MDU submitted a letter that revised its filing to reflect changes resulting from the federal Small Business Jobs Act. The Act contained a 50 percent bonus tax depreciation for 2010, which applied to MDU's 2010 plant additions and reduced the revenue requirement originally filed by MDU by $562,511, to $4,939,830.

6. Intervenor pre-filed testimony was submitted by Encore on December 17 and December 20, 2010, and by MCC on December 17 and December 23, 2010.

7. On January 27, 2011, the Commission issued a Notice of Public Hearing.

8. On January 31, 2011, MDU filed its rebuttal testimony.

9. On February 8, 2011, the Commission issued Interim Order 7115b, granting MDU interim rate relief of $2,640,725 to be allocated to customer classes on a uniform percentage basis.

10. On February 23, 2011, a joint request from MDU, MCC and Encore to vacate the noticed February 28, 2011, hearing was received by the Commission.

11. On May 9, 2011, MDU, MCC and Encore submitted an all-party Stipulation that, if accepted by the Commission, would resolve all contested issues in the case.

12. On May 12, 2011, the Commission issued a Notice of Public Hearing regarding public witness hearings to be held in Sidney, Montana, and Miles City, Montana. On June 1, 2011, a public witness hearing was held in Sidney, Montana. On June 2, 2011, a public witness hearing was held in Miles City, Montana.

13. On May 17, 2011, MDU filed a Motion in Limine (Motion) seeking an order from the Commission which admits into evidence all pre-filed testimony and exhibits in the docket without the need for each witness to be physically present at the hearing. The Motion stated that MCC and Encore agreed to support such an order. After a duly noticed business meeting, the Commission granted the Motion with the condition that certain witnesses, to be identified by the Commission and its staff, would be available by telephone and it issued Order No. 7115c on June 20, 2011.

14. On May 31, 2011, the Commission issued a Notice of Public Hearing regarding the public hearing to be held in Helena, Montana. On June 29, 2011, the public hearing was held in Helena, Montana, as noticed.

Summary of Prefiled Testimony on Revenue Requirements Issues

MDU Direct Testimony

David L. Goodin

15. Goodin, president and chief executive officer of MDU, provided an overview of the utility's electric operations and explained that the major reasons for MDU's rate increase application were: (1) increased investment in facilities, including expansion of wind generation in the Cedar Hills and Diamond Willow projects - Goodin said MDU's gross investment in Montana electrical operations has increased by over $58 million from the end of 2006 to the pro forma levels included in the case; (2) a decline in MDU's total company wholesale sales margin from $9.8 million in 2006 to $600,000 in 2009; and (3) recovery of the deferred generation costs associated with the proposed Big Stone II, Gascoyne and Milton Young III generation projects.

Andrea L. Stomberg

16. Stomberg, MDU's vice president of Electric Supply, listed the following MDU capital investments that were included in the application: a $4 million new Montana substation that was built in 2007; a $3.4 million interconnection for the Cedar Hills wind farm; over $12 million in substation upgrades; $4.6 million in generation efficiency projects; $10.1 million in generation-related environmental projects; $2.3 million in generation-related risk reduction projects; $7.5 million in generation operation sustaining projects; an estimated $3.56 million for the Heskett Station Unit 1 maintenance and upgrade project; and significant investments in new wind generation and the Glen Ullin waste heat recovery unit.

17. Regarding MDU's proposal to recover from Montana ratepayers approximately $3.4 million, or close to 25 percent, of MDU's development costs associated with the canceled Big Stone II coal plant, Stomberg said MDU's costs were prudently incurred to develop a generating resource even though the plant will not be built. She explained that MDU pursued the Big Stone II project with other project owners after determining it would be a prudent long-term generating resource, but abandoned it when it was clear that, due to changed circumstances, it was not likely to be built. According to Stomberg, MDU also seeks to recover costs it incurred to evaluate two other baseload projects that were not built: the Gascoyne coal plant in North Dakota ($2.1

million) that was abandoned in favor of the ill-fated Big Stone II project and the Milton R. Young III coal plant ($332,000).

18. Stomberg stated that MDU constantly evaluates potential new sources of power to serve its customers and that both the Gascoyne and Milton R. Young III plants were opportunities to achieve economies with regional power plants. Stomberg asserted the plant development costs were a necessary cost associated with the development of MDU's next generating facility and should be recovered from customers.

19. Stomberg explained that, after requesting proposals, MDU secured a purchased power agreement that along with existing resources will meet customer needs through 2015.

J. Stephen Gaske

20. Gaske, senior vice president of Concentric Energy Advisors, Inc., provided testimony on the cost of common equity based primarily on his Discounted Cash Flow (DCF) analysis of a group of proxy companies that have similar risks as that of MDU's Montana electric utility. He described his analyses and concluded with recommending a return on equity (ROE) for MDU of 11.5 percent. This, he said, was within the range of his analyses of between 10.9 and 13.4 percent.

Garret Senger

21. Senger, MDU's controller and chief accounting officer, sponsored MDU's exhibits of the balance sheet for December 31, 2009, and June 30, 2010, and income statement for periods ending December 31, 2009, and the 6 months ending June 30, 2010. Senger also testified regarding the overall cost of capital, capital structure and overall debt and preferred equity costs. Senger stated that the overall rate of return sought by MDU is 8.778 percent. According to Senger, the debt costs in this application reflect a 40-basis-point reduction in borrowing costs from the cost of debt agreed to in the settlement of MDU's last rate case. He explained that MDU's requested 11 percent ROE within the overall requested rate of return is supported by Gaske's testimony, but that the requested return also recognizes the current economic environment and is a 50-basis-point reduction from Gaske's recommended ROE of 11.5 percent.

Darcy J. Neigum

22. Neigum, MDU's systems operations and planning manager, stated that the expiration in 2006 of a long-term power contract with Basin Electric along with the 2005 startup of the Midwest ISO energy market and the subsequent ancillary services market significantly reduced

MDU's opportunities for wholesale sales of excess electricity. According to Neigum, going forward MDU expects to see continued decreased wholesale sales and margins compared to historical levels. For 2010, he said MDU forecasted wholesale sales of 122,768 MWh, an annual margin of $667,752 with an average margin per sale of $5.37 per MWh.

23. Neigum discussed MDU's new generating resource additions since 2007. They include: the 19.5-MW Diamond Willow wind project, which commenced commercial operation in February 2008 and is already included in rates; the 5.3-MW Glen Ullin #6 heat recovery generating station, which commenced commercial operation in June 2010, and cost $16.7 million; the 10.5-MW expansion to Diamond Willow, which commenced commercial operation in June 2010, and is estimated to cost $24.9 million; and the 19.5-MW Cedar Hills wind project, which commenced commercial operation in June 2010, and cost $46.6 million.

24. Neigum said that MDU will meet Montana's 2010 Renewable Portfolio Standard (RPS), which requires that 10 percent of the electricity to serve Montana customers comes from renewable sources. The Montana RPS requirement increases to 15 percent in 2015; Neigum said MDU's addition of the Diamond Willow expansion means MDU is on its way to satisfying the 2015 requirement.

Stephanie L. Bosch

25. Bosch, MDU's regulatory analyst supervisor, discussed the development of the pro forma sales volume that formed the basis for Adjustment No. 1 to operating revenues.

Rita A. Mulkern

26. Mulkern, MDU's regulatory analysis manager, sponsored electric utility income statement exhibits and explained and supported with workpapers the adjustments that MDU made to the actual expenses in developing the test period cost of service. She also sponsored exhibits showing the calculation of MDU's revenue requirements for the utility. Mulkern explained MDU's proposals for changes to the fuel and power cost tracking adjustment. MDU proposed to eliminate the wholesale sales margin sharing adjustment and, instead, credit 85 percent of all wholesale margins as a credit in the fuel and power cost tracking adjustment. MDU also proposed to include Midwest ISO regional market administration charges in the fuel and power supply cost tracking adjustment.

27. Mulkern provided MDU's responses to the issues the Commission directed MDU to address in the PSC's final order in the last rate case: MDU's treatment of sales for resale and the

merits of decoupling. Regarding MDU's treatment of sales for resale, Mulkern pointed to Neigum's testimony on the decline in wholesale sales margin and MDU's proposal to eliminate the current wholesale sales margin sharing adjustment and replace it with a credit in the fuel and power cost tracking adjustment. Regarding decoupling, Mulkern testified that MDU does not recommend implementing a decoupling mechanism at this time.

AUS Consultants

28. AUS Consultants performed depreciation studies on both the MDU-Utilities Common Plant and MDU-Electric Division based on a year ending December 31, 2008.

29. The proposed rates, if applied for common plant for December 2008, would result in a depreciation expense of $1,677,496 rather than the present (2008) expense of $2,410,513, a decrease in depreciation expense of $733,017. This is a change in the composite rates from 5.63 percent to 3.92 percent.

30. For the same period for MDU's Electric Division, the study suggests an annual depreciation expense of $23,812,407, rather than $22,087,830, which is an increase of $1,724,577 from the 2008 rates. This is a change in the composite rates from 3.04 percent to 3.27 percent.

MCC Response Testimony

Albert Clark

31. Clark, a consultant for MCC, concluded that MDU's revenue increase request of $5,502,581 (subsequently reduced to $4,939,830) is excessive. He recommended a revenue increase of no more than $583,696. Additionally, Clark suggested if the Commission rejected the proposed margin sharing arrangement with a base of $0, the level of the allowed revenue increase should be reduced by an additional amount to account for a revenue credit for off-system sales revenues at the representative level of sales included as the base.

32. Clark recommended rejecting MDU's post-test-year adjustments that are based on MDU's 2010 operating budget. Clark's proposal recognizes actual increases and decreases experienced after the close of the test year and the most recent 12 months of actual data. According to Clark, his change represents a known and measurable level of cost as opposed to a speculative budget amount as used by MDU.

33. Clark made the following adjustments to MDU's pro forma results of operations: increase MCC and PSC taxes by $54,642; increase test year miscellaneous revenues by $19,585;

reduce the 401-K expense by $30,660; reduce postage expense by $4,460; reduce insurance expense by $16,458; reduce subcontract labor by $486,877; reduce labor expense by $169,393; increase post-retirement benefit expense by $29,382; increase medical/dental expense by $20,844; reduce worker compensation expense by $8,556; reduce uncollectible expense by $726; reduce advertising expense by $6,304; reduce the Montana electric allocation by $27,653 to reflect Clark's proposed change in the allocation of the North Dakota Coal Conversion Tax; reduce test-year expenses for the Montana electric operation by $5,879 to reflect use of the capacity allocation factor as related to production at the Lewis & Clark station and to the transmission function; reduce test year property taxes by $58,204; and reduce the Supplemental Income Security Program (SISP) expense by $353,660.

34. Clark proposed an adjustment to reflect the depreciation rates that MCC witness Jacob Pous determined to be appropriate. The revised depreciation rates have an impact on depreciation expense and the accumulated provision for depreciation.

35. Clark proposed adjustments to MDU's rate base. First, he recommended the amount of post-test year plant that should be included in rate base is $2,788,976 of post-test-year plant additions rather than MDU's proposed $7,541,539. Clark argued that no post-test-year plant should be included in rate base because, in his opinion, MDU did not show that the plant is non-income producing and because his analysis determined that some of the plant MDU proposed for inclusion in rate base had not been in service within 12 months after the close of the historical test year and was therefore ineligible. Clark noted his proposed reduction in plant affects depreciation expense, the depreciation reserve and property taxes.

36. Clark also proposed rate base reductions of $1,422,816 related to the accumulated provision for depreciation; $580,005 related to including accumulated deferred income taxes in rate base; and $137,108 related to reallocating the Diamond Willow deferred income taxes on the same hybrid basis as MDU proposed for allocating the plant's costs.

37. Clark's final adjustment to rate base (and an accompanying adjustment to expense) was related to MDU's proposal to include deferred generation costs in its revenue requirement. MDU claimed total costs of $15,296,364, of which $3,788,440 was allocated to Montana electric operations. MDU requested the cost to be amortized over 10 years and that the first year average unamortized balance be included in rate base. Clark objected in part to the total costs claimed and objected in total to the rate base inclusion. He contended there is no justification for

ratepayers to pay a return on capital for projects that never did, and never will, produce a plant that is used and useful.

38. Clark proposed to allow the amortization of the expenditures over a 10-year period with one adjustment that would provide for a return *of* the capital to stockholders, but not a return *on* it. Clark proposed removing the $2,387,019 in Allowance for Funds Used During Construction (AFUDC) from the total amount to be amortized, allocated down to Montana electric operations, and reducing the claimed amortization expense by $68,099.

39. Clark accepted MDU's proposal to reflect bonus depreciation for 2010 plant additions, but only to the extent that 2010 plant was included in rate base. Clark calculated that approximately $410,000 of the claimed revenue requirement reduction was related to the Diamond Willow expansion and the Cedar Hills wind farm. Clark stated that the remaining $153,000 of MDU's proposal was related to its claimed level of other post-test year plant investment. Since he proposed to remove the majority of these post-test year investments, the portion related to plant not included in rate base should not be reflected in the revenue requirement. He proposed to disallow approximately 63 percent of MDU's proposed 2010 plant investment, and would then restore 63 percent of the $153,000 to the revenue requirement.

40. Clark's last adjustment to the pro forma income statement was to synchronize the interest expense with the capital structure and the rate base plus non-rate base construction work in progress. The effect of the adjustment was to decrease interest expense by $308,204, which, in turn, increased current income tax expense by $121,394.

41. Clark recommended against approval of MDU's proposed margin-sharing mechanism unless a larger share of the margins flows to ratepayers and MDU's fuel and purchased power adjustment mechanism is approved with a similar sharing arrangement as proposed by Wilson.

42. Clark recommended the Commission reject MDU's proposed new Renewable Resource Cost Recovery Rider Rate 56 and Transmission Cost Recovery Rider Rate 57. Clark opposed the rate schedules because he said they both anticipate single-issue rate adjustments; MDU offered no explanation of their use; it appears they could result in blanket preapproval for investments in unspecified future projects; and there is no reason for the Commission to agree to these rate schedules and examine the results of their applicability later.

Jacob Pous

43. Pous, a principal in the firm of Diversified Utility Consultants, Inc., filed testimony on behalf of the MCC in response to the depreciation study submitted by MDU. The MDU study was based on overall plant as of the end of December 31, 2008, and resulted in a proposed $22,087,830 total company annual depreciation expense. The proposal in the study represented an increase of $1,724,577 compared to the depreciation expense that would occur utilizing current rates. Pous limited his analysis to Production plant accounts. He noted that the $1.7 million increase in depreciation expense in MDU's study is actually a $2,706,497 increase for production plant and a $981,920 reduction to plant other than production plant.

44. Pous identified three main production plant issues. Regarding production plant life, he recommended life spans that reflect either MDU's expected retirements during the planning horizon of its Integrated Resource Plan or a 60-year minimum life span, which he said had the net effect of an approximate $3.5 million reduction to total company depreciation expense. Regarding interim retirements, Pous recommended a retirement ratio approach based on company-specific history, which he said would result in a $1.2 million net reduction to total company depreciation expense. Regarding production plant net salvage, Pous recommended relying on more recent decommissioning cost estimates than MDU did to arrive at an approximate $2.2 million reduction in annual depreciation expense.

45. According to Pous, the combined impact of his recommendations is a $6.2 million reduction to total company production plant depreciation expense (prior to the allocation to the Montana retail jurisdiction).

John Wilson

46. Wilson, president of J.W. Wilson & Associates, provided testimony on behalf of MCC on the issues of rate of return and capital structure. Wilson performed a DCF analysis, a Capital Asset Pricing Model (CAPM) analysis and a comparable earnings analysis. He recommended an ROE range between 8.5 percent and 10 percent. Wilson proposed a 9.5-percent ROE to calculate a recommended return on rate base. Wilson claimed his 9.5-percent ROE acknowledges that MDU has provided and is expected to continue to provide adequate service to its Montana customers and also recognizes the modest level of business risk for electric utility service and MDU's comparatively high common equity ratio. Based on a 9.5 percent ROE allowance, MDU's allowed return on its electric utility rate base would be 8.0 percent:

	Ratio	Cost	Allowed Return
Long Term Debt	43.239%	6.845%	2.960%
Short Term Debt	3.211%	2.535%	0.081%
Preferred Stock	2.397%	4.592%	0.110%
Common Equity	51.153%	9.500%	4.860%
		Overall Return	**8.011%**

47. Wilson used the actual capital structure in his calculation of rate of return but stated that a 50-percent common equity ratio is at the high end of the reasonable range for electric utility ratemaking.

Encore Response Testimony

Michael P. Gorman

48. Gorman, a consultant and managing principal with Brubaker and Associates, Inc., testified on capital structure and rate of return issues. He did not object to MDU's proposed capital structure. To derive his ROE recommendation, he used a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, a risk premium analysis, and a CAPM analysis. Gorman stated that these analyses estimate a fair ROE based on observable market information for a group of publicly traded electric utility companies that approximate MDU's investment risk. Gorman recommended an ROE of 9.6 percent with a range of between 9.4 percent and 9.8 percent. He recommended an overall rate of return of 8.06 percent.

49. Gorman also responded to the analysis performed by Gaske of MDU. He stated that MDU proposed an ROE of 11.5 percent based on Gaske's use of DCF analysis and the inclusion of flotation costs. Gorman stated that Gaske's estimates were flawed in that the growth rates used by Gaske do not represent long-term sustainable growth, but forecast growth rates for the next five years and Gaske's internal steady-state growth rates were much lower than the three- to five-year growth estimates and illustrates the non-sustainability of the short-term analyst growth rates. Gorman also stated that Gaske's flotation cost ROE adder was not based on MDU-specific equity issuance cost and as result the flotation cost adder is not a legitimate cost to include in MDU's cost of service.

David E. Peterson

50. Peterson, a consultant in the firm Chesapeake Regulatory Consultants, Inc., addressed revenue requirement issues, excluding the issues of capital structure and cost of capital.

51. Peterson stated MDU claims to have used a 12-month test period ended December 31, 2009, but its rate base presentation included forecasted plant additions through December 2010. He recommended the Commission reject MDU's post-test period adjustments. By removing post-test year plant additions, excluding the new wind resource assets, he reduced MDU's Montana rate base by $1,379,443.

52. Peterson adjusted MDU's rate base for Diamond Willow Expansion and the Cedar Hills wind projects and the first-year operating costs associated with running those two facilities. His adjustment used 32.8 percent energy and 67.2 percent demand jurisdictional allocation factors for MDU's wind investments testified to by Encore witness Rosenberg. The adjustment reduced rate base by $1,218,005.

53. Peterson objected to several of MDU's proposed rate base allowances as being outside the 2009 test period. His proposed adjustments in the categories of materials and supplies, fuel stores, prepaid insurance, unamortized loss on reacquired debt, and customer advances for construction.

54. Peterson said that the effect of his recommended rate base adjustments is to reduce MDU's electric rate base by $6,131,118, resulting in a rate base of $81,120,268.

55. Peterson recommended the following adjustments to MDU's pro forma operating income: adjust depreciation, property tax and income tax to exclude the effects of post-test year plant additions ($412,417); Diamond Willow re-allocation ($70,710); remove incentive compensation expense ($662,040); adjust depreciation expense ($2,880); shorten the amortization period for decommissioning of retired plant costs from ten to three years ($40,000); reduce advertising costs ($6,304), reflect consolidated tax savings in Montana rates ($556,404); and interest synchronization.

56. In addition, he disagreed with MDU's cost recovery proposal for the canceled Big Stone II, Gascoyne and Milton R. Young III generation projects. Peterson recommended the abandoned projects' cost be shared between MDU and ratepayers by excluding the accrued AFUDC, amounting to $2,387,019 on a total company basis from cost recovery, amortizing recoverable costs over a 40-year period, and excluding the unamortized recoverable costs from rate base. The effect of his proposed sharing mechanism on MDU's proposed revenue requirement is to reduce MDU's proposed annual amortization allowance by $298,899 and rate base by $3,598,854.

57. Peterson concluded that MDU understated its earnings potential under present rates by $1,571,308. He contended that MDU's request for a $5.5 million rate increase is excessive and that a rate increase of $483,958 would allow MDU to achieve Encore's recommended 8.06 percent overall rate of return.

MDU Rebuttal Testimony

Rita A. Mulkern

58. Mulkern disagreed with MCC witness Clark's general criticism of MDU's use of the 2010 operating budget. She contended MDU did not use the budget on a wholesale basis; rather the budget was used as a guide to determining increases or decreases in expenses affecting the test period. She also stated that Clark was inconsistent in deriving his revenue and expense levels because, in some cases, he used the 12 months ending October 31, 2010 expense levels, but, in others, he annualized year-to-date 2010 expenses.

59. Regarding Clark's adjustments to the KVAR penalty revenue, Mulkern contended that MDU's use of a three-year average was appropriate and that Clark had not objected to it in the last rate case when the three-year average was higher than the per-books amount. She said if the Commission decides that the two-year historical and one year budget information is appropriate, then that time period should be used in future cases. She argued the makeup of the three-year time period should not change in order to pick the lowest three-year period in each case. Mulkern made the same point regarding Clark's incentive compensation adjustment.

60. Mulkern claimed Clark understated MDU's insurance expense amount because he did not take into account the known and measurable changes that occurred in insurance premiums effective November 2009, January 2010 and April 2010.

61. Mulkern said Clark erred in his calculation of subcontract labor by calculating it as a credit of $331,437 instead of an expense of $331,437. When corrected, she said the adjustment would be an increase of $175,997 rather than a decrease of $486,777.

62. Regarding Clark's SISP expense adjustment, Mulkern argued Clark's position in this case is inconsistent with his position in previous MDU cases. Mulkern contended Clark changes his position on including or excluding SISP expense depending on whether it increases or reduces the revenue requirement.

63. Mulkern disputed Clark's adjustment to remove the deferred generation balance from rate base because she said Clark also should have eliminated the associated accumulated deferred

income tax balance from rate base in order not to overstate the adjustment. If the Commission accepted Clark's proposal, she said this correction would result in an increase in rate base of $673,342.

64. Mulkern said MDU does not object to Clark's adjustments to post-test period plant additions, but contended Clark's calculation of ad valorem taxes when restated for the plant additions should have included construction work in progress not yet classified, the AFUDC interest and depreciation on Coyote, and the reallocation adjustment for the wind generation.

65. Mulkern stated that with respect to the sharing of the fuel and purchased power tracking adjustment amounts, MDU believes its proposal to share 85 percent of all margins is more beneficial to customers than to establish a base with sharing over (under) a base as proposed by Clark.

66. Mulkern disagreed with MCC witness Wilson's contention that the MISO market administrative charges should not be included in the fuel and power tracking adjustment. She argued that market administrative charges are directly related to MDU's fuel and purchased power and, prior to MISO, were included in the energy cost of purchased power.

67. Regarding Encore witness Peterson's adjustments based on his interpretation of the test year in this case, Mulkern argued that Peterson had incorrectly interpreted the Commission's administrative rule and previous direction regarding the "known and measurable" standard. Mulkern contended MDU's plant additions and related adjustments met the known and measurable standard applied by this Commission. In this case, she said, MDU maintained test year relationships and included only those plant additions that were non-revenue producing.

68. She disputed Peterson's use of a strictly historical rate base that effectively disallowed MDU's recovery of the full investment in the Glen Ullin plant. She said Peterson failed to recognize the full investment in generation which has been providing electricity to customers since July 2009.

69. Mulkern contended Peterson's adjustment to prepaid insurance should be rejected because, she argued, Peterson ignored both the known and measurable standard and the matching principle.

70. Regarding Peterson's opposition to MDU's use of a three-year historical average of incentive compensation, Mulkern said MDU has consistently used that average in the development of an adjustment to labor expense in its rate cases in order to smooth out the year-

to-year fluctuations that occur. Mulkern disagreed with Peterson's argument that since the budgeted incentive compensation for 2010 was less than the three-year historical average, the use of the average was wrong.

71. Mulkern called Peterson's proposal to amortize the deferred generation costs over a 40-year period unreasonable. Referring to Peterson's testimony about "dragging out" for 10 years the amortization of the unamortized cost of the decommissioning of retired plants, Mulkern said there is no reason to drag out the recovery of deferred generation costs over 40 years. She also said Peterson made the same error as Clark in that he removed the unamortized deferred generation balance from rate base but failed to remove the associated accumulated deferred income taxes.

72. Mulkern disagreed with Peterson's proposal to amortize the unamortized balance of decommissioning costs on retired generation plants over three years rather than the five years proposed by MDU. MDU prefers a five-year period because it does not know if it will be filing a general rate case within the next three years and a five-year amortization would provide more flexibility in returning the unamortized balance to customers.

Alvin J. Feist

73. Feist, the tax planning director of MDU Resources Group, Inc., disputed Peterson's consolidated tax savings adjustment. Feist explained that under the stand-alone methodology that MDU uses to calculate taxes, the tax benefit/burden must be given to the member of the consolidated group that is responsible for generating the income or paying the expenses giving rise to a deduction or a tax burden. Feist said MDU has long used the stand-alone method for allocating consolidated tax liability in rate cases in Montana, North and South Dakota and Wyoming. He said the Federal Energy Regulatory Commission (FERC) has also supported the use of the stand-alone method of allocating income taxes among members of a consolidated group when a jurisdictional company is part of a group filing a consolidated income tax return. Feist cited specific FERC opinions and language that approved the stand-alone methodology. Feist cited a circuit court decision that sustained the FERC's application of the stand-alone methodology. Feist also said the stand-alone method conforms to generally accepted accounting principles, referring to the Accounting Standards Codification (ASC) regarding accounting for income taxes. According to Feist, the ASC has determined that the method proposed by Peterson is not consistent with its broad principles.

74. Feist disagreed with Peterson's argument that MDU realized tax savings by filing a consolidated return. He said tax benefits associated with the net operating losses of affiliates should not be considered as "tax savings." Feist provided an example of the timing nature of a tax loss by a non-regulated affiliate. The affiliate had a tax loss in Year 1 of $50,000 and taxable income in Year 2 of $50,000. If the affiliate was not a member of a consolidated return, it would be able to carryover its loss to Year 2 and offset its taxable income in Year 2, resulting in zero tax payable in Years 1 and 2. However, he said, Peterson's proposal would convert the timing nature of this benefit into a permanent tax loss to the non-regulated affiliate.

75. According to Feist, proper ratemaking policy is to keep regulated and non-regulated entities separate to the extent possible. He argued that there is no evidence that MDU's customers are bearing the expenses resulting in the tax deductions at any of the affiliated companies. He said the Commission would not allow MDU's customers to be burdened with the expenses of the affiliated companies and the Commission should likewise recognize that it would be inconsistent for MDU's customers to be allocated the tax benefits that were realized as a result of the expenses incurred by the affiliated companies.

76. Feist did not agree with Peterson's contention that ratepayers are paying for tax losses of MDU's unregulated affiliates. He said the cash benefit received by the affiliates as a result of these tax losses is not being paid by the MDU customers, but essentially is being received from the government. Feist said if the Commission reverses its past position on the stand-alone method, this change in policy would retroactively penalize MDU Resources for organizational decisions which were made in reliance on the past policy of this Commission.

77. Feist contended that Peterson ignored the 2008 MDU tax loss when he computed his five-year average and that this position is contrary to the treatment Peterson argued should be given to losses of non-regulated affiliates. He said that, under Peterson's proposal, MDU would share in the benefit of any tax losses for non-regulated affiliates, but the affiliates would not be allowed to share in the benefit of the 2008 tax loss generated by MDU. Feist indicated that Peterson's calculation should be revised to reflect the 2008 MDU tax loss and that revising Peterson's calculation results in a Montana current tax adjustment of a positive $1,047,988. MDU's requested recovery of Montana electric allocated income taxes would need to be increased by this amount, Feist said.

78. Feist argued the correct income tax allowance is determined using a stand-alone method, which results in no adjustment to the amount reflected in MDU's filing.

Anne Jones

79. Jones, MDU's human resources director, disagreed with Peterson's proposal to eliminate all incentive compensation amounts from Montana rates. According to Jones, incentive compensation should remain in MDU's cost of service because the incentive plan is designed for employees and senior management to focus on customer service metrics, safety and controlling operating and maintenance costs. She also stated that meeting an earnings threshold before payout is in customers' best interest and is common in the utility industry. According to Jones, if the Commission disallowed incentive compensation based on performance, the only viable alternative is to increase base pay to remain competitive in the labor market and retain a viable, qualified work force. She contended base pay is the most expensive way to compensate employees because other benefits such as pension and 401K contributions are dependent on base salary.

Garret Senger

80. Senger disagreed with Clark's and Peterson's recommendation to disallow AFUDC for the deferred generation costs. He said the AFUDC costs were prudently incurred to minimize long-term costs to the customers, MDU expended capital for those projects, and accruing AFUDC is a cost of the project. Senger contended that MDU followed the FERC-prescribed formula for applying AFUDC. He added that disallowing recovery of AFUDC as proposed has the potential to increase the long-term overall cost of debt and capital.

81. Regarding the issue raised by MCC witness Pous about the decommissioning rates, Senger responded that MDU is currently recording the authorized rates for decommissioning costs and has not proposed to change those rates in this case. He said MDU recognizes the need to update its decommissioning study and is in the process of developing a new study.

Earl M. Robinson

82. Robinson, a director of AUS Consultants who prepared MDU's 2008 depreciation study, disputed several aspects of the testimony of MCC witness Pous. He said Pous was selective in his rejection of MDU's increase in depreciation expense for Production plant while apparently accepting MDU's reduction for Other Plant. He claimed Pous ignored MDU-specific data and therefore his recommendation is unsupported.

83. Robinson claimed that Pous' estimates of potential life spans, the level of interim retirements that he estimated to occur during the property's life, and extrapolation of the commodity scrap values to the company's plant are irrational and inappropriate and led to what Robinson termed Pous' radical reductions to not only MDU's proposed generation plant depreciation rates, but also to its current level of annual depreciation rates.

84. Robinson disagreed with Pous' opinion that MDU used artificially short service lives for its production plant. He pointed to significant additional investments that have been made to the initial construction of the Heskett and Lewis and Clark plants from years earlier that have extended their life spans to a range of 57 to 66 years. Robinson said it is only through continued extensive investments that generation plants are able to attain the average 60 years proposed by Pous as an initial life for steam production plants. According to Robinson, Pous' proposal of a very long initial service life estimate inappropriately defers cost recovery to a future customer instead of recovering the costs over the life of the property consistent with a customer's use of and benefit from the property and related investments.

85. Robinson also took exception to Pous' assertion that MDU's 2009 IRP does not identify production plant retirements in a manner consistent with average service lives in the depreciation study. Robinson stated that the depreciation study and the IRP serve different purposes.

86. Robinson disagreed with Pous' position that an actuarial approach to estimate the average service life is inappropriate. He said that either the actuarial approach or life-span approach can be used. He stated that the analysis method used by MDU is appropriate and that Pous used an alternate mixture of inputs that resulted in a lower depreciation recommendation. Robinson stated that Pous argued against using a full mortality method stating that a majority of companies use a life span approach. Robinson stated that in his sample group, at least 50 percent used an actuarial, semi-actuarial or judgment approach. Robinson stated there is no one standard for the calculation of remaining plant life and that Pous' mix-and-match approach is invalid.

87. Regarding the issue of interim retirements, Robinson asserted that his Iowa Survival Curve/life analysis approach is appropriate and that Pous' suggested constant interim retirement rate based upon the prior 30 plus historical years is incorrect. Robinson's argument was that Pous' calculated average retirement was backward looking and gave no consideration to the increasing level of interim retirement rates as property continues to age.

88. Robinson stated that Pous' criticisms of the revision of the interim retirement curve and of the change in the curve scale between the 2002 and 2008 MDU depreciation studies are incorrect. He said a different scale has no impact on the depreciation study results and that the bottom line is that the high level of retirements has continued during the more recent period. Robinson asserted the higher retirement levels have historically continued over numerous years and there is every reason to believe that this pattern will continue into the future. Robinson stated that it is obvious that MDU's now proposed Iowa 50-R1 life and curve is clearly a superior representation of the applicable interim retirements as compared to the prior estimated 80-L0 life and curve.

89. Regarding production plant net salvage, Robinson took note of Pous' criticism of the use of the 1984 Stone and Webster fossil fuel decommissioning study and of MDU's position that the study provided a reasonable estimate of decommissioning costs. Robinson stated that MDU is presently using the authorized decommissioning rates and is not proposing any changes to decommissioning costs in this case.

J. Steven Gaske

90. Gaske responded to Wilson's and Gorman's ROE recommendations. He said his primary objection to Gorman's analysis is that he gave no consideration to his Constant Growth DCF results, which indicated an average required return for the proxy group of 11.19 percent and a median return requirement of 10.94 percent. Gaske argued that Gorman's analysis confirmed the reasonableness of his ROE recommendation.

91. According to Gaske, the most significant flaw in Wilson's analysis was the implausibility of many of its results. For example, he said, there were several instances where Wilson estimated that the required ROE was negative. Gaske contended another flaw in Wilson's analysis was the use of the entire group of 54 companies that Value Line classifies as electric utilities, plus MDU Resources Group, in his proxy group. Gaske said many of these companies are not comparable to MDU's electric utility operations and to use them as an input into the calculation of an appropriate ROE for MDU is inappropriate.

92. Gaske said he disagreed with Gorman and Wilson in other areas of their analyses, including: (1) growth rates used in their respective DCF analyses; (2) dividend yield adjustments; (3) the use of a CAPM analysis; and (4) the appropriateness and application of a

flotation cost adjustment. Furthermore, he disagreed with Gorman on the approaches used in their respective risk premium analyses and the risks faced by MDU's electric operations.

93. Gaske concluded by stating Gorman's and Wilson's recommended ROEs are inadequate because the they are based on flawed analyses and that when those analyses are corrected or refined, they support Gaske's rate of return recommendation.

Summary of Prefiled Testimony on Cost of Service & Rate Design Issues

MDU Direct Testimony

Tamie Aberle

94. Tamie Aberle, MDU's pricing and tariff manager, presented the results of MDU's embedded class cost of service study and addressed the effect of MDU's revenue requirement proposal on electric rates and customer class revenue responsibilities. She also described MDU's proposed changes to non-price tariff terms and conditions and addressed the reserved issues from Docket No. D2007.7.79 pertaining to inverted block rate structures and smart metering.

95. Aberle sponsored Statement L, which contains the details of MDU's embedded cost of service (ECOS) study. The ECOS study is based on the 12 month test period ended December 31, 2009 adjusted to reflect pro forma adjustments as sponsored by Mulkern.

96. To determine what costs to assign to each customer class, Aberle began by classifying the functionalized costs by FERC account for all rate base and income statement items as demand-, energy-, or customer-related. She directly assigned to appropriate customer classes the plant, expense, and revenue items that are identified in the FERC accounts as directly related to a specific class of customers. She allocated remaining costs using the allocation factors shown in Statement L on the basis of cost responsibility.

97. Aberle allocated investments in production and transmission plant items with an Average and Excess Demand (AED) allocator, based on a combination of the classes' average demand and non-coincident peak demand. Aberle testified that MDU analyzed each distribution plant account and allocated costs therein based on the cause for investment. Station equipment and the associated land and land rights were allocated based on the non-coincident peak demand of each class. Other distribution plant items were classified as customer- and demand-related based on an analysis of the minimum and normal system design for a typical distribution system,

with the minimum system representing the percentage of the plant accounts assigned to the customer component and the remainder classified as demand-related. That analysis indicated that the minimum investment necessary to connect a customer constitutes 82 percent of Accounts 364 (Poles, Towers & Fixtures), 365 (Overhead Conductors), 366 and 367 (Underground Conduit and Underground Conductors and Devices). She allocated customer-related distribution costs to each rate class based on the number of customers served in each rate class, and allocated the remaining demand-related distribution costs to each rate class based on the maximum demand of each rate class.

98. Aberle classified line transformers as customer- and demand-related. She used a minimum intercept method to determine the customer-related component. She explained that the minimum intercept method seeks to identify the portion of the transformer investment associated with a hypothetical zero-load condition. She calculated the zero intercept to be $1,446 and multiplied this amount by the number of transformers, which resulted in a customer component of 76 percent. She classified the remaining 24 percent of transformer costs as demand-related. She allocated the customer- and demand-related transformer costs according to weighted customer transformers and non-coincident secondary demand factors, respectively.

99. She classified the four remaining distribution cost accounts (services, meters, installation on customer premises and street lights and signal systems) as customer-related. She allocated services and meters costs to customer classes based on weighted customer factors. She directly assigned costs for installation on customer premises to the outdoor lighting class. Similarly, she directly assigned investment in street light and signal systems to the municipal lighting class.

100. With respect to the allocation of income statement items, Aberle explained that she directly assigned revenues to each customer class based on the revenues produced by each class. Any other revenues that she could not directly assign to a particular rate class she allocated based on the source of the revenue. She classified fuel, purchased power, and variable production expenses as energy-related and allocated them based on the energy requirements of each class. She classified other production expenses and purchased capacity costs as demand-related and allocated them using the AED allocator used to allocate production plant costs. She classified transmission operation and maintenance (O&M) costs as demand-related and allocated them

with the AED allocator. She said she allocated the remaining O&M expenses based on cost causation.

101. Aberle primarily used the ECOS study as a guide to apportion the proposed revenue increase to customer classes. The class revenue changes needed to bring each of the rate classes to the overall rate of return ranged from a 110 percent increase for Irrigation Rate 25 to a 29 percent decrease for Outdoor Lighting Service Rate 52. She did not propose reducing rates for the Outdoor Lighting Rate 52, but she did not allocate any of the revenue increase to that class. In allocating the revenue increase to each class, Aberle imposed a 14.5-percent cap in order to mitigate the increase to any one rate class. Aberle said the proposed rates move toward cost-based rates but do not fully reflect MDU's estimated marginal and embedded costs. Aberle's proposed class revenue increases are shown below.

Proposed interim and final rate level increases

Class	Interim	Final
Residential	7.43%	14.5%
Small general service	7.43%	13.0%
Large general service	7.43%	12.3%
Municipal pumping	7.43%	14.5%
Lighting	7.43%	8.6%
Overall	**7.43%**	**13.0%**

102. Aberle proposed increasing the base rate component (or Basic Service Charge) to $0.25 per day, or $7.60 per month, which is an increase of $2.60 per month over the current rate. She contended that amount is below the $20.92/month customer component supported by the ECOS and the $23.78/month customer cost component shown by the marginal cost study. She said MDU proposes a daily basic service charge in order to avoid prorating the monthly charge.

103. Aberle derived residential class energy rates by reducing the class's total revenue responsibility by the proposed basic service charge revenues, the seasonal differential and the projected base fuel and purchased power component for secondary service. She divided the remaining revenues by pro forma Rate 10 kwh sales to determine the rate per kwh. This produced a rate of $0.07548/kwh during summer months and $0.05148/kwh during winter months. A Base Fuel charge of $0.02084/kwh would be added to both of these rates to

determine the total energy rate. Aberle stated that she used the same process used to calculate the proposed rate components for each of the other rate schedules.

104. Aberle testified that MDU continues to offer optional time-of-day rate schedules consisting of Residential TOD 16, Small General Service TOD Rate 26 and Large General Service TOD Rate 31. These rates are designed to provide customers with an incentive to shift load to the off-peak period.

105. Aberle explained that MDU proposes to offer a new Option Residential Electric Thermal Energy Storage Rate 13 to residential customers with electric space heating that also use a thermal storage system during the off-peak hours of 10 p.m. to 8 a.m. The proposed rate for this rate schedule is a discount of $0.025 per kwh from residential rate 10.

106. She testified that MDU also proposes to offer a new General Electric Space Heating Service Rate 32, which would offer General Service customers with electric space heating an optional rate that recognizes that space heating load occurs during a period outside of the system peak. The rate would discount demand charges during the heating season October through May. The energy charges and summer season demand charge for Rate 32 would be the same as those under Large General Service Rate 30. The space heating load served under Rate 32 would be metered separately from the customer's other electric requirements.

107. Aberle explained that the proposed electric service rate schedules each contain four separate adjustment mechanisms:

a. Universal System Benefits Charge (Rate 55): the existing adjustment mechanism established to recover funds to support the Universal System Benefits program.

b. Renewable Resource Cost Recovery Rider (Rate 56): a proposed adjustment to recover costs for future investment in renewable resources. The renewable resources in the revenue requirement in this rate case (Diamond Willow wind, Cedar Hills wind and the waste heat recovery unit) would not be part of the adjustment.

c. Transmission Cost Recovery Rider (Rate 57): a proposed adjustment to recover transmission investments and federally regulated transmission related costs charged to MDU that are not part of the rates established in this rate case. The request is to establish the mechanism for future use in recovering applicable expenditures and an adjustment is not proposed to be charged at this time.

d. Fuel and Purchased Power Adjustment (Rate 58): mechanism currently established to recover the cost of fuel and purchased power.

108. Aberle addressed the reserved issue of inverted block rates from PSC Order No. 6846f, Docket No. D2007.7.79. She said that while MDU provided information in Docket No. D2009.4.56 for Residential rate schedule 10 reflecting an inverted block rate based on various assumptions, that same exercise has not been repeated in this rate case. She asserted that the fuel charge component of the energy charge is the component that would most appropriately be charged on an inverted basis because it is the true variable component that would be avoided through customer response to a price signal. She recommended making the fuel and purchased power component a separate line item on customer bills. She added that MDU does not have the ability to bill on an inverted basis at this time but indicated that MDU's new billing system would be capable of billing the fuel and purchased power charge on an inverted basis in the future.

109. Aberle also provided information on MDU's Automated Meter Reading (AMR) program as required in Order No. 6846f. She testified that MDU's AMR system is more than a meter reading system because of the communication network and use of Itron Corporation's Meter Data Management System (MDM). The MDM system is a first step in providing customers with more real time information and enhanced pricing options. She said that the AMR system is operational from the meter reading and billing perspective, with meter data collected from approximately 75 percent of the automated meters in place, and the remaining 25 percent of the automated meters being mobile read. Interval data is transmitted through the fixed network system, but the MDM system necessary to aggregate and store the interval data is not yet functional. MDU is working to enable the MDM system. She said MDU remains committed to initiating a load control program and recently refreshed the estimated cost to install and implement a program in conjunction with Honeywell Utility Solutions. Under this program, MDU would have the ability to cycle a participating customer's central air conditioner with the use of a programmable thermostat installed within a customer's home. She expects the program to get under way in the second quarter of 2011. She added that MDU will evaluate an expanded portfolio of conservation programs, including the load control program, as part of the 2011 Integrated Resource Planning process.

James Heidell

110. James Heidell, vice president of NERA Economic Consulting, presented MDU's marginal cost of service (MCOS) study.

111. Heidell stated that his study followed the commonly-used approach of cost functionalizing costs, classifying them, and allocating them to customer classes. He testified that his MCOS study reflects an estimate of marginal costs for 2012 to comply with ARM 38.5.176, which requires an estimate of costs for the study year two years beyond January 1 of the year in which the study is filed. His objective was to estimate long-run marginal costs, where long-run is a five- to ten-year horizon. He separately estimated marginal costs for generation, transmission lines, transmission substations, and distribution services. In the case of marginal generation costs, he used MDU's chronological dispatch model to estimate marginal energy costs over an eight year period, 2012-2019. He reported that MDU had less information on long-term projections of marginal transmission and distribution costs. So, to estimate these costs, he used a combination of historical costs and current actual or estimated construction costs. When using costs from different years, he adjusted them to 2012 dollars based upon an assumed inflation factor or the Handy Whitman index.

112. Heidell derived MDU's marginal generation cost by first preparing a forecast of levelized marginal energy and capacity costs over a period of 2012 through 2019. He calculated marginal energy costs using the PROSYM hourly chronological production cost model. Specifically, he used cost differences between a base case scenario and a scenario with 20 MW of incremental load to develop marginal costs for eight time periods: on and off-peak periods in winter (December – February), spring (March – May), summer (June – August), and fall (September – November).

113. He asserted that MDU's production cost model determines the least-cost dispatch of the mix of resources available to meet MDU's load based on assumptions including unit availability, heat rates, fuel costs, and ramp rates. The base case scenario reflected key assumptions about the future, including MDU's retail load, estimates of future fuel prices, and characteristics of existing generation units and power contracts. The incremental load scenario used the same assumptions about fuel costs and existing generation units and power contracts. He used a combustion turbine to ensure incremental peak loads were met, but noted that the incremental load is also served by available generation resources and market purchases defined in the base case.

114. Heidell incorporated greenhouse gas externality costs through additional PROSYM modeling. He used a PROSYM report on the percent of hours that a fuel group is on the margin

during each month for the peak and off-peak periods to assign a marginal generation unit to each time period and calculate emissions per MWh based on the plant's heat rate and the emission rate for the fuel. He calculated the marginal cost of CO_2 emissions for each month and each period based upon the weighted average time that each fuel is on the margin. He calculated these costs under two CO_2 emissions cost scenarios: $30/ton and $50/ton in 2012, with both scenarios assuming a 2.5 percent annual escalation rate (2012-2019).

115. Heidell calculated levelized marginal generation capacity costs for two time periods. For the first period, 2012-2014, he based marginal capacity cost on recently acquired summer peaking contracts. For the second period, 2015-2019, he based marginal capacity cost on the levelized cost of building a 75-MW gas-fired combustion turbine. He then levelized the costs over the full 2012-2019 period. He increased the resulting marginal capacity cost by 15 percent to reflect reserve requirements, and made adjustments for property taxes, G&A and revenue taxes.

116. Heidell also determined the marginal cost for reactive power supply based on the cost of a line capacitor project. The cost of the capacitor was unitized by dividing the capacity of the unit with adders for O&M and G&A expenses. The reactive power marginal cost is expressed in $/KVAR and assigned to rate classes that have KVAR penalty charges for customers with power factors outside of the tariff range.

117. Heidell based transmission line marginal costs (MCs) on the cost of new transmission to integrate gas-fired generation projects and recent transmission investments. He determined marginal transmission costs using two components. The first component reflects the cost of new lines to integrate new generation. The second component captures other transmission line investments, presumably for load growth and reliability, based on historical costs over the past nine years. He summed these two costs and adjusted the result for O&M, G&A, property tax, and other tax adders to compute his marginal transmission cost.

118. Heidell calculated distribution substation MCs using an estimate of the cost of constructing two projects: the Sheridan substation (at $40/KW) and the Miles City substation (at $14/KW). He based his marginal substation cost on an average of the cost of these two projects. He levelized the capital costs using a fixed charge rate and applied adders for O&M, G&A, and other taxes. He classified marginal substation cost as 100-percent capacity related and allocated

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costs to each class based upon the non-coincident peaks of the Montana customer classes using Aberle's ECOS AED allocator.

119. Heidell calculated distribution MCs using the cost for distribution lines, transformers, service lines, and metering. He calculated the marginal cost of distribution lines by estimating the per-mile cost of constructing new distribution circuits in Montana. Then he converted that cost to a cost per customer using data on the number of circuits, circuit miles, and customers on the Montana system. He classified these costs as demand- and customer-related based on Aberle's ECOS minimum system study, which classified 82 percent of the distribution costs as customer-related.

120. Heidell calculated marginal line transformer costs based on the estimated cost of a new transformer. The cost is class specific and reflects a weighting of the size of the transformer used by each customer class. Line transformers were classified as demand- and customer-related, with the customer proportion based on a linear regression of line transformer size as a function of cost where the intercept of the regression line is the customer proportion. He calculated the customer portion for each class based upon the average number of customers on a line transformer.

121. Heidell stated that MDU staff provided him with the marginal cost for service lines, which apply only to residential and small commercial customers. He testified that larger commercial and industrial customers taking service at primary voltage have their own underground service line and do not require this service. Heidell estimated the marginal cost of metering based on five year averages of historical costs associated with meter reading, billing, and sales expense.

122. Heidell explained that his MCOS study used the same energy, demand, and customer allocation factors Aberle used in her ECOS study, noting that the demand and energy allocation factors reflect applicable voltage level losses. He also explained that MCOS studies do not allocate all costs, like an ECOS study, but only those associated with an increment or decrement of load. He stated that marginal costs may be either greater than or less than average costs. In fact, he noted that his MCOS study indicates that total system marginal costs, not including externalities, are about 35 percent higher than the embedded cost revenue requirement. Heidell did not find this surprising because replacement costs are usually higher than historical costs and

the MCOS study does not adjust equipment costs to reflect that used equipment typically has less value than new equipment because part of its economic life has been used up.

123. In order to annualize capital investments within his MCOS study, Heidell calculated nominal levelized fixed charge rates (LFCR) based on the capital structure and cost of capital used in the ECOS and applicable book life assumptions. LFCRs for generation, transmission and distribution investments were calculated as the annual equivalent cost of an associated capital cost divided by the initial cost. The LCFRs incorporated the annual debt and return on equity assuming the annual book depreciation for each type of investment, tax depreciation, normalization of taxes, and income taxes.

124. Heidell multiplied his marginal unit cost estimates by loss-adjusted energy and demand allocation factors at the customer class level to determine total MCs at the class level, inclusive of losses. These allocation factors were adjusted by the same demand and energy loss factors used in the ECOS. Heidell stated that if the PSC uses marginal unit costs to guide rate design, they should be adjusted for the class loss factors used in the ECOS study.

125. Heidell's MCOS study produced a marginal generation energy cost (w/o externalities) equal to $0.0436/kwh. The study also indicated that during coincident peak hours, marginal generation demand costs equal $9.10/KW-month, marginal transmission demand costs are $4.88/KW-month, and marginal substation demand costs are $1.47/KW-month. He explained that he allocated marginal generation energy costs to customer classes based on loss adjusted sales and marginal generation, transmission, and substation demand costs according to Aberle's AED allocator. He allocated distribution demand-related costs based on class non-coincident peaks. The table below compares the results of Heidell's MCOS study to Aberle's ECOS study:

Comparison of class-level embedded and marginal costs

Rate Class	Embedded Total (2010)	Marginal Total (2012)	Marginal / Embedded
Residential Rate 10	$15,079,800	$19,542,054	30%
Small General Rate 20	8,620,814	11,730,215	36%
Irrigation Power Rate 25	349,820	467,187	34%
Large General Primary Rate 30	2,531,408	3,407,459	35%
Large General Secondary Rate 30	8,802,824	11,931,252	36%
Large General Service TOD Rate 31	687,031	933,215	36%
Contract Services Rate 35	10,277,786	14,581,157	42%
Municipal Pumping Rate 48	552,608	739,822	34%
Private Lighting Rate 52	227,369	246,828	9%
Street Lighting Company Owned Rate 41	471,893	499,788	6%
Street Lighting Municipal Owned Rate 41	81,025	101,863	26%
Total	$47,682,378	$64,180,840	35%

Encore Response Testimony

Alan Rosenberg

126. Alan Rosenberg addressed MDU's embedded and marginal cost of service studies and rate design proposals, particularly for Large General Electric Service (Rate 30).

127. Rosenberg disputed several aspects of Aberle's ECOS study. He asserted that Aberle miscalculated Factor 3, which allocates fixed wind costs, by incorrectly computing a weighted average of each class's energy (kwh) and demand (KW). He stated that because kwh and KW are not like units, Aberle's weighted average produces a meaningless figure.

128. Rosenberg contended that Aberle arbitrarily classified 80 percent of the fixed costs of wind as energy-related and the remaining 20 percent as demand-related, without providing any supporting analysis. He testified that all fixed generation costs are customarily classified as demand-related, but admitted that wind generation differs from conventional generation because it has no fuel costs, is not dispatchable, and is intermittent. However, he stated that these differences in no way imply that 80 percent of wind fixed costs are energy-related. Rosenberg contended that a more appropriate classification of fixed wind would reflect the fuel and purchased power costs that additional wind generation is expected to save, plus wind generation tax credits, as a percent of the cost of additional wind generation. Using this approach, he estimated that 32.8 percent of wind costs should be classified as energy-related, and the balance classified as demand-related. He asserted that using his 32.8/67.2 split instead of MDU's 80/20

split for classifying energy and demand costs would reduce Montana's share of fixed wind generation costs from 28.22 percent to 26.17 percent, and reduce Montana's revenue requirement by approximately $386,407.

129. Rosenberg disagreed with Aberle that her AED allocator method is widely accepted, contending instead that it is in relative disuse and that the PSC has not specifically endorsed it. He also asserted that none of the parties to the settlement in Docket No. 2007.7.79 endorsed the method. Rosenberg expressed concern that the AED allocator classified 75 percent of costs as energy-related. He asserted that in light of MDU's expected growth and need for additional capacity (exacerbated by the termination of the Big Stone project), the AED's emphasis on energy and de-emphasis on demand conveys the wrong price signal to customers and unduly penalizes classes that control their peaks.

130. Rosenberg testified that the AED method over-emphasizes energy because Aberle used a low system peak value. He noted that while Aberle used a 474 MW system peak, MDU witness Stomberg testified that MDU's 2010 summer peak is forecast to be 525 MW and MDU's IRP forecast a 2010 summer peak of 539.5 MW. He concluded that Aberle's 474 MW peak is unrealistic and distorts cost responsibility and cost causation. He added that he calculated a 127 MW Montana coincident peak using the hourly loads supplied in data response EC-113, while Aberle used 114.9 MW as Montana's coincident peak.

131. Rosenberg developed an AED allocator that: 1) attributed 24.26 percent of the system summer peak demand to Montana (similar to Aberle); 2) corrected Aberle's mathematical errors in her Factor 3 calculation; 3) assumed a Montana coincident peak demand of 127,365 KW; and 4) assumed a 32.8/67.2 energy/demand classification for wind. With his revised AED allocator, 41,410 KW would be allocated on class excess demand (compared with Aberle's 28,982 KW), 67.5 percent of conventional generation and transmission fixed costs would be allocated on energy, and over 78 percent of wind costs would be allocated on an energy basis.

132. Rosenberg opposed using the AED allocation method in this case, asserting that the method ignores class-level coincident peak demands and leads to price signals that frustrate efficiency. He contended that some type of coincident peak allocation method would be more appropriate. He said he would accept the use of a 12 CP method (as recommended by Mulkern) for the allocation of transmission plant costs, but objected to weighting all months equally because the peak in some months will not approach the system peak, and will have hardly any

influence on capacity requirements. He recommended a three summer (July-September)/two winter (January-December) coincident peak method to allocate demand-related costs, which would reduce Montana's share of demand-related generation costs from 24.765 percent to 24.356 percent. He presented modified ECOS study results that incorporate his recommended 5CP methods. Rosenberg contended these results more accurately reflect cost causation than the AED studies.

133. Rosenberg contended that MDU witness Heidell made two significant errors in his MCOS study. First, he asserted that Heidell overestimated marginal costs by using questionable and uncertain forecasts far into the future. Second, he argued that Heidell inappropriately multiplied marginal generation and transmission demand-related costs by the AED "demands" from Aberle's ECOS study.

134. Rosenberg asserted that Heidell's annualized $41.88/MWh marginal energy cost is well above the average MISO Day Ahead Price of $27.61 per MWh (for period 11/09-10/10). Rosenberg contended that the MISO Day Ahead Price must serve as a ceiling for MDU's marginal costs because if MDU's marginal costs were higher it would be more economical to buy from the market.

135. Rosenberg said Heidell's decision to estimate marginal energy costs over an eight year period reflects a misinterpretation of ARM 38.5.176. According to Rosenberg, that rule actually requires the MCOS study be computed in dollars two years beyond January 1st of the year the filing is submitted. In other words, in this case the rule requires costs stated in 2012 dollars, but does not specify 2012 as the year in which costs must be measured, as Heidell appeared to believe.

136. Rosenberg testified that instead of using actual data or estimates for the near future, Heidell used estimates of production costs for the period of 2012-2019 in his MCOS study. Rosenberg found these estimates unreasonable. He noted that Heidell's model produced an average variable production cost of $32.01/MWh, which is 36 percent greater than MDU's test year average variable production cost. He said Heidell estimated even higher production costs in the outer years of his study. Rosenberg maintained that forecasting costs that far out in the future unnecessarily adds uncertainty. He asserted that that the PROSYM model Heidell used to estimate production costs is capable of estimating costs for a one or two year time horizon and it is not necessary to run the model over an 8-year time horizon. He contended that no

authoritative text on ratemaking that he is aware of recommends estimating marginal energy based on long range forecasts and, hence, Heidell's approach is not consistent with economic theory.

137. Rosenberg stated that even if Heidell's marginal energy cost estimates were theoretically defensible, using inflated marginal costs would disrupt the goal of setting rates based on cost causation because artificially exaggerating the energy component diminishes the role of demand and sends poor price signals. Rosenberg also testified that Heidell's two MCOS studies with CO_2 externality costs result in highly speculative prices that are unlikely to materialize into real costs by 2012. Rosenberg said that including these hypothetical costs exacerbates the problem of inflated energy costs.

138. Rosenberg modified Heidell's MCOS study by using $25.57 per MWh as the marginal cost of energy and calculating generation capacity costs using each class's coincident peak demand.

139. Rosenberg emphasized the importance of setting rates based on actual cost. He said that confronting customers with price signals that convey the consequences of their consumption decisions in turn provides correct signals to the utility about the need for new investment and furthers the goals of stability, conservation and efficiency. He agreed with Aberle's decision to rely on the ECOS study for revenue allocation, although he did not agree with some of the particulars of her study. He also agreed that if MDU is granted a 13 percent overall revenue increase, no class should get a revenue decrease. However, he said that if the PSC grants MDU an increase that is significantly less, for example less than 7 percent, than if the cost study indicates decreases are warranted for some classes they should be implemented.

140. Rosenberg disagreed with Aberle's 14.5 percent cap on revenue increases for any class, noting that 14.5 percent is barely 1.1 times the system average of 13.0 percent, and caps are usually in the order of 1.5 to 2.0 times the system average. He asserted that if the system average increase is granted at 13.05 percent, the cap should be 1.75 times that, or 22.83 percent. For a system increase between 5 percent and 7 percent he recommended a cap 2.0 times the system average. For a system increase of 4.5 percent or less he recommended a 10 percent cap.

141. Rosenberg proposed class revenue requirements that assume the PSC grants MDU full revenue relief and that reflect Aberle's ECOS study with his corrected AED allocator. His proposals also reflect the following: 1) any class that requires a decrease from current rates to be

brought to COS is not allocated any portion of the increase; 2) Rate 35 is adjusted to COS with the exception that it does not receive a decrease as long as the system increase is 13.05 percent; 3) revenues from all classes other than Rate 35 are increased as necessary to bring them to COS, but not by more than 22.83 percent; 4) any revenue shortfall from applying the cap is reallocated to all classes that are not capped in proportion to their COS; and 5) if all classes, other than the ones capped at 22.83 percent, are in need of a decrease in order to reach COS, the shortfall is allocated to all those classes in proportion to their COS, so as to minimize any distortion.

142. Rosenberg testified that his preferred allocation method for MDU in this rate case would be based on multiple coincident peaks. Rosenberg's recommended spread of the increase based on his preferred study is shown in Ex. AER-8. Rosenberg stated that should the PSC not follow his recommendation of relying solely on the ECOS study, he would recommend the PSC use the MCOS study to allocate the production revenue requirement, but still use the ECOS study to allocate the transmission and distribution revenue requirement. The results of this type of allocation are summarized in Ex. AER-9. Rosenberg cited a recent PSC docket for a NWE case (Docket No. D2009.9.129) in which all of the major parties in the case agreed that an ECOS analysis is the most appropriate benchmark for determining class responsibility and revenue requirements for transmission, distribution, and customer costs. Rosenberg supported that approach, noting that the *NARUC Electric Utility Cost Allocation Manual* states "...the determination of marginal costs for these [transmission, distribution, and customer costs] functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort." For comparison purposes, Rosenberg provided class revenues based solely on a MCOS study in Ex. AER-10.

143. Rosenberg testified that he has concerns with MDU's proposed rate design for Large General Service Rate 30 in particular. Rosenberg stated that, according to the ECOS study, about one-third of the total cost for Large General Service is comprised of energy-related costs, predominantly fuel and purchased power. But, according to Rosenberg, Aberle advocated collecting about three-quarters of the revenue through the fuel charge plus the energy charge. Rosenberg disagreed with this approach because: 1) it penalizes customers with high load factors that use energy at a relatively constant rate;, 2) it does not incent customers to control peak demands, and 3) it means MDU would recover much of its fixed costs with variable charges, so

if Large General Service usage turns out to be significantly greater than test year levels, MDU will over-earn.

144. Rosenberg offered a different rate design for Rate 30. First, he set customer charges for the Primary and Secondary customers at $185/month and $70/month, respectively. He noted that although these proposed charges are 1½ to 2 times that proposed by Aberle, the customer charges would still only recover about 2 percent of the total revenue target. Next, he set the energy rate for the Primary class at $0.0100 per kwh, which means that the energy rate, plus the base Fuel and Purchased Power charge, will be above the average marginal energy cost. He stated that although the total energy rate would be more than the embedded energy cost with his rate design, the difference would be smaller than it would be with Aberle's proposal. He also eliminated the seasonal differential in the energy charge, retained Aberle's $1.00 differential in the demand charge between winter and summer months, and included a differential in the demand charge for Primary and Secondary customers in the amount of $0.23/KW per month to reflect higher losses for lower voltage customers and the additional facilities that are used to provide Secondary service but not Primary service. He provided his preferred rate design for Rate 30 and also provided an alternative rate design that assumed no increase in Rate 30 class revenues.

145. Rosenberg recommended rejecting MDU's proposed transmission cost recovery rider (Rate 57) and renewable resource rider (Rate 56) because they are vague, unnecessary, bad regulatory policy, and poorly designed. He believes the riders are vague because Rate 56 does not specify what qualifies as a renewable resource or how the costs of that investment will be calculated, and Rate 57 states that it includes facilities constructed to improve capacity or reliability, but it does not explain whether that is a necessary condition or a sufficient condition, or contain guidelines for determining the purpose of the new transmission facility. Rosenberg believes the proposed riders appear to be crafted to adjust automatically, much like a fuel and purchased power adjustment mechanism (Rate 58). Rosenberg stated that Rate 58 is an exception to traditional regulation because of three distinguishing characteristics: 1) fuel costs are material, representing over 30 percent of the requested revenue requirement in the test year, 2) fuel costs can be highly variable, and 3) fuel costs, to a large extent, can be outside the control of the utility. He asserted that MDU has not shown that the costs associated with the proposed riders are substantial, highly variable, and outside MDU's control. Therefore, he finds the riders

unnecessary. He asserted that the riders make for bad regulatory policy because stakeholders cannot challenge the legitimacy, need, or accuracy of the costs in question, and because the riders focus on one single element of the cost structure while ignoring other changes in costs, investment, and revenue. Rosenberg stated that the riders are structured to recover costs through a uniform cents-per-kwh charge applicable to all retail energy sold, without taking into account that the retail classes have different load factors, different coincidence factors, and different loss factors. Rosenberg also expressed concern that neither transmission nor renewable resource costs are energy-related, yet will be recovered on the basis of energy consumption.

MCC Response Testimony

John W. Wilson

146. John Wilson addressed MDU's cost of service study. He contended that MDU's ECOS study contains faulty classification and allocation procedures that result in residential and small business customers being charged more than their fair share of MDU's revenue requirements. He disputed MDU's use of the AED cost allocation method for generation and transmission costs, and the minimum system approach for classifying distribution costs.

147. Aberle's ECOS study uses an AED allocation method to classify and allocate generation costs. Wilson disputed the reasonableness of the AED allocation method for generation costs because it uses NCP demand rather than CP demand, and results in a cost allocation that closely resembles an allocation based solely on monthly coincident peak demands, without giving any consideration to energy consumption. He contended that generation plant investment levels are related to energy consumption and monthly coincident peak demands, but not individual class NCP load. Because MDU's ECOS study results in an allocation that so closely resembles an allocation based solely on monthly coincident peak demands, Wilson asserted that the study distributes benefits so that classes with peaks coincident with the system (such as high load factor industrials) are assigned a smaller share of total system costs, and classes with high diversity (such as the residential class) are assigned a larger portion of the total costs. He contended that MDU's approach fails to properly classify generation costs on the basis of both demand and energy.

148. Wilson asserted that in allocating generation costs it is increasingly recognized that hours other than the peak hour are critical from a system planning perspective, and regulators and utilities have moved toward multiple peak allocation methods as well as the classification of

generation plant costs between energy and demand responsibility. Wilson said two methods that classify generation costs as both demand and energy-related are the Average and Peak method and the Equivalent Peaker method. The Average and Peak method combines each class's average demand with its peak demand to develop a class allocator. He said that with this allocator the system load factor determines the percentage of plant costs considered energy-related and the remainder (1-load factor) is considered demand-related and allocated in proportion to each class's CP demand. The Equivalent Peaker method uses the ratio of the cost of peaking capacity per unit of load (KW) to the utility's total capacity cost per unit of load to determine the percentage of generation plant costs classified as demand, with the remainder classified as energy.

149. Wilson contended that a large portion of MDU's base load and renewable generation plant investment is driven by energy requirements, and recommended an allocation method that incorporates a balanced energy and demand weighting into the classification of generation costs. He said that in this case, MDU's cost allocation would have been more reasonable if its generation plant allocator had used 12-CP demand instead of excess demand to allocate the portion of the generation plant costs that were not classified as energy. The 12-CP method is based on the combination of the twelve monthly system coincident peaks, rather than on the basis of contribution to the single highest hourly demand during the year. It attempts to capture some of the relevant cost-causative attributes of the monthly loads that a utility must serve and recognizes that generation and transmission capacity is installed not only to meet coincident peak demand, but also to maintain system reliability during all months of the year. Wilson used the 12-CP method in his suggested modification of MDU's COS study.

150. Wilson raised similar concerns with MDU's use of the AED allocator to classify and allocate transmission costs. He asserted that utilities use base load plants and associated transmission grids to produce, coordinate, and deliver energy around-the-clock as well as to satisfy customers' average level of demand. He testified that a portion of MDU's high capital costs are justified by energy consumption and not by the coincident or non-coincident demands of the various classes.

151. Wilson contended that transmission costs should also be classified as both demand and energy, and asserted that a cost-minimizing utility maintains a mix of generating resources to meet varying demands and reduce overall production costs, thereby lowering the cost of both

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capacity and energy. Ideally, a utility will use its transmission grid to achieve optimal dispatch and reduce energy costs, and Wilson believes the classification of transmission costs should recognize that. Wilson stated that the same is true for large transmission level substations. The transmission substations are typically needed on integrated systems that efficiently tie remote base load and wind-powered plants to network load centers, but their costs are not primarily attributable to the cost of peak demand. Wilson testified that transmission investment and expense is clearly related to both the transport and network integration of less costly energy from base load plants to support both demand and energy needs, and as such, should be assigned to both energy and demand classifications. Wilson believes that if MDU should use the AED allocator in its classification and allocation of costs, it would be more appropriate to use 12-CP demand within the allocator as opposed to NCP demand.

152. To illustrate the resemblance between MDU's AED allocation method and an allocation based solely on monthly coincident peak demands, Wilson provided the following table, which shows the percentage of costs allocated to each major class under MDU's AED allocator, a coincident peak demand allocator and an energy-only allocator:

Share of costs allocated to customer classes with different allocators

Class	Average and Excess %	Coincident Demand %	Energy %
Residential	26.91%	26.37%	23.52%
Small General Service	18.51%	19.33%	16.03%
Large General Service	51.65%	51.39%	57.99%

153. Wilson also contested how MDU classified and allocated distribution costs. In particular, Wilson faulted MDU's decision to classify nearly 80 percent of its distribution costs as customer-related, and none as energy-related. MDU used a "minimum distribution system" (MDS) method to determine the customer-related portion of distribution plant costs, which it then allocated to customer classes on the basis of the number of customers in each rate class. Since the residential rate class has the largest number of customers, it gets assigned a high percentage of distribution plant costs.

154. The MDS methodology involves estimating the cost of a theoretical system of minimum-sized plant capable of serving a minimum (i.e. near zero) load, but still connecting all customers. But Wilson contended that MDU used contemporary standard equipment and conventional system construction designed to meet today's actual and anticipated loads in

costing out its estimate of a minimum-size system, resulting in substantial costs that are clearly load related. As an example, Wilson pointed to MDU's response to data request PSC-001, wherein MDU indicated that they had used expensive pad mounted transformer equipment to estimate minimum distribution system costs. Consequently, MDU considered 76 percent of the costs in Account 368-Transformers customer-related. Wilson contended that 57 percent of those costs would be customer-related if less costly line transformers were used. According to Wilson the total cost of a theoretical minimum system designed to serve a near zero load would be no more than 10-25 percent of actual distribution costs.

155. Wilson contended that investments in distribution lines and related equipment contribute to an integrated power delivery network, and, therefore, are not customer-specific investments that are causally attributable to customer counts. To support his view he cited from Bonbright's *Principles of Public Utility Rates*, which reports a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system, likely because such calculations fail to consider the density of customers in an area. Bonbright also cites a regression analysis (Lessels, 1980), in which no statistical association was found between distribution costs and number of customers. Wilson commented that while NCP demand is an appropriate cost allocator for distribution facilities that are installed to meet lower voltages in local areas, a 12-CP method is likely to be a more appropriate choice to allocate primary distribution costs that are driven by more broadly based regional requirements.

156. Wilson summarized his alternative cost of service study in Ex. JWW-10. He classified generation and transmission costs as 50 percent energy-related and 50 percent demand-related, and allocated the energy portion in proportion to class energy loads and the demand-related costs in proportion to average monthly coincident peak demands (12 CP). Similarly, he classified distribution costs 50 percent energy-related and 50 percent demand-related, and allocated the energy-related costs in proportion to class energy loads and the demand-related costs in proportion to non-coincident peak demand. He also made several other changes in his COS study, including 1) reallocating revenue credits (sales for resale and margin sharing) and A&G expenses on the basis of retail revenues and 2) allocated materials and supplies on the basis of total plant rather than on the basis of only production, transmission and distribution.

157. Wilson testified that if a COS study has correctly attributed the proper portion of total costs to each rate class, an appropriate rate structure would result in equal rates of return for each

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class. Wilson contended MDU's COS study has under-allocated costs to high load factor customers, and has over-allocated costs to smaller, lower load factor customers. Wilson stated that if MDU's plant costs are reallocated to more properly reflect energy responsibility for plant investment the calculated rates of return for customer classes change substantially, and the results indicate that residential customer rates produce returns that are well above the system average:

Indicated rates of return (before adjustments)

Rate Class	MDU's COS Study	Wilson's COS Study
Total Company	5.157%	5.157%
Residential	4.127%	8.791%
Small General	4.859%	5.729%
Large General	5.904%	3.148%
Mun. Pumping	-0.328%	-0.995%
Lighting	9.077%	9.667%

158. Wilson questioned the efficiency of MDU's proposed rate design. He noted that small general service (Rate 20) and residential (Rate 10) customers would pay higher rates in the summer months than in the winter months, while large general service (Rate 30) and contract (Rate 35) customers would pay the same energy rates in all months. For example, large general service customers taking service at primary voltage would pay $0.045/kwh in summer months, but small general service subscribers, also taking voltage at primary voltage, would pay $0.067/kwh. Residential customers, who do not have demand charges, would pay $0.096/kwh. Wilson questioned the reasonableness of these widely varying prices.

159. Wilson criticized MDU's proposal to increase monthly charges for all customer classes while reducing the per kwh energy charge for large general service customers in the summer months. He said that increasing customer charges and reducing peak season energy charges is not a sensible rate design change for a utility that is concerned about improving price signals to promote efficient energy consumption because per customer charges play no role in efficiency. He added that MDU's rate design proposals send customers inconsistent price signals for incremental energy consumption. As an example he noted that residential customers would be told that incremental cost of an additional kwh is 9.6¢ in summer months, while large contract service customers would be told the cost of an additional kwh is 3.9¢. Wilson contended that, in fact, at any particular time the incremental cost an additional kwh is exactly the same regardless

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of which customer's load is varying. Wilson believes incremental energy rates are the strongest energy conservation tool available to utilities because they allow customers to directly respond to the price signals they are receiving with regard to the cost of an increase or decrease in kwh consumption. Wilson stated customers cannot respond to per-customer charges and capacity charges that are more or less fixed in the short term.

160. Wilson summarized his recommendations as follows: 1) residential rates should not be raised because MDU is already collecting all costs associated with serving these customers; 2) flat monthly customer charges should not be raised for any customer class, because they do not contribute to efficient energy consumption decisions; 3) any increase in rates for non-residential classes should be imposed through energy charges; and 4) to the extent that seasonal energy rate differentials are appropriate, they should be adopted for all customer classes, and the summer energy charge reductions that MDU proposes for large general service customers should not be approved.

161. Wilson concluded by addressing MDU's proposed tracker (Rate 58) and rider rates (Riders 56 and 57). He stated that trackers and cost adjustment riders offer only one advantage – they provide prompt and more frequent adjustment of electric utility rate levels in response to changes in the costs on which they are focused than is possible in complete rate investigations. In contrast, he identified several disadvantages including: 1) rate adjustments may go in one direction while the utility's total costs are moving in the other direction, since the adjustments are based upon consideration of only some rather than all of the utility's costs; 2) partial cost adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering offsetting factors, such as productivity improvements, that reduce total costs; and 3) trackers may tend to weaken or distort incentives for a utility to supply electricity at a minimum cost because of the opportunity to change rate levels very quickly in response to certain cost changes between rate cases, and pass gains or losses on to ratepayers rather than shareholders.

162. Regarding Rate 58, MDU proposed adding MISO administration charges to fuel and purchased power costs and to change the split of wholesale sales margins by reducing the base value to zero and by allocating 15 percent (rather than 10 percent) to the benefit of MDU shareholders. Wilson believes there is no more reason to include MISO administrative charges than any other administrative costs in the tracker, and believes that doing so would eliminate

MDU's financial incentive to attempt to minimize these costs. He recommended rejecting MDU's proposed changes to Rate 58 and maintaining the balanced 90/10 split for both margin sharing and changes in fuel and purchased power costs.

163. Wilson finds the proposed new riders for transmission and renewable resource cost recovery (Rates 56 and 57) unusual and troubling from a traditional regulatory perspective. The proposed new riders would allow transmission and renewable resource cost increases without traditional general rate case consideration and would allow for immediate rate adjustments. He said such adjustments would not take account for associated cost offsets that may occur because of these investments. Likewise, transmission investment, which is often closely integrated with a substitute for generation costs, would be passed onto consumers in rate adjustments without considering related generation cost offsets. Wilson recommended rejecting these proposed new riders.

MDU Rebuttal Testimony

Tamie Aberle

164. Aberle agreed with Rosenberg that generation-related costs should be classified as demand-related, but disagreed with his proposal to allocate costs based on a 5-month coincident peak demand allocator (January, July, August, September, and December). Aberle asserted that the AED allocation factor is more reasonable because, while a portion of MDU's generating facilities are associated primarily with serving peak demands, the majority of the generating capacity is baseload associated with serving average demands throughout the year. She contended that in MDU's last electric rate case Encore's consultant proposed and endorsed the AED method for allocating generation and transmission costs.

165. She disagreed with Wilson's approach of classifying 50 percent of generation costs as energy-related and 50 percent demand-related, and allocating the energy-related costs on the basis of energy sales. She contended that the AED approach recognizes the energy use of each class without recovering demand-related costs through an energy component.

166. With respect to transmission function costs, Aberle acknowledged that classifying those costs as demand-related using a 12-CP allocator, as Rosenberg recommends, is an acceptable alternative to MDU's AED method. She disagreed with Wilson, who recommended classifying transmission costs 50 percent energy-related and 50 percent demand-related. She asserted that

transmission costs are fixed and it is not appropriate to recover them through a variable component.

167. Similarly, Aberle objected to Wilson's proposal to classify 50 percent of distribution function costs as energy-related and 50 percent demand-related. She maintained that there is no basis for classifying distribution costs as energy-related or allocating those costs on the basis of energy use. In support of her position, she points to NARUC's *Electric Utility Cost Allocation Manual*, which states:

> ...all costs of services can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.[1/]

168. Aberle testified that MDU followed the preferred classification of distribution plant and distribution expenses discussed in the NARUC manual.

169. On page 6 of her rebuttal testimony, Aberle compares the effect of Rosenberg's and Wilson's recommended cost of service approaches to MDU's. The table below summarizes her comparison:

	Revenue @ current rates [1]	Cost of Service		
		MDU [2]	MCC [3]	Encore [4]
Residential Service	12,898,287	15,079,800	12,893,150	17,701,947
Small General Service	7,825,066	8,970,634	8,677,518	9,483,160
Large General Service	20,283,319	22,299,049	24,766,134	19,509,514
Municipal Pumping	381,466	552,608	588,311	543,278
Lighting	791,659	780,287	757,236	489,492
Total Montana Electric	42,179,797	47,682,378	47,682,349	47,727,391

1 Statement H

2 Statement L

3 Wilson cost of service workpapers

4 Rosenberg Exhibit AER-8

170. Aberle observed that Wilson's cost of service approach shifts revenue responsibility away from smaller energy use residential and small general service customers to the large energy

[1/] *Electric Utility Cost Allocation Manual*. National Association of Regulatory Utility Commissioners, January 1992.

use large general service and contract service customers. In contrast, Rosenberg's approach shifts revenue responsibility away from the large general service and contract customers to the residential and small general service customers. She added that Wilson's classification approach shifts about $19 million in cost responsibility from demand and customer components to energy components, compared to MDU's cost of service methods, and results in classifying about 70 percent of MDU's revenue requirement as energy-related. She contended that this result is illogical given the capital intensive nature of the electric system's infrastructure and the obligation to provide safe, reliable service. She also testified that Wilson's cost of service methods shift about $6 million in rate base from the residential and small general service customer classes primarily to large general service classes, resulting in a negative rate base customer component for the Residential, Small General Service and Irrigation service classes. She said that outcome is not credible because those classes represent 98 percent of all MDU's Montana customers. Aberle concludes that the PSC should consider MDU's cost of service study a reasonable approach to determining class revenue responsibilities and establishing pricing components.

171. Aberle acknowledged that MDU's ECOS model contained an error in the calculation of the allocation factor applied to wind generation costs. The error resulted in slightly under-weighting the demand component in the AED allocation method.

172. With respect to rate design, Aberle testified that Rosenberg's recommendation to cap class revenue increases at 22.83 percent should be rejected as too large. She characterized MDU's 14.5-percent cap as a more balanced and gradual move toward cost of service. Aberle also disagreed with Wilson's recommendations that the PSC not increase customer charges. She contended that fixed costs should be recovered from customers in the customer charge or base rate in order to minimize intra-class subsidies. She added that reduced energy use due to conservation should not lead to unrecovered fixed costs.

173. Finally, Aberle renewed her support for the Renewable Resource Cost Recovery and Transmission Recovery riders. She maintained that the purpose of these riders is to allow the Company a way to recover primarily capital costs that are outside the Company's complete control without going through the expensive and lengthy rate case process.

James Heidell

174. Heidell filed rebuttal testimony addressing Rosenberg's concerns regarding MDU's marginal cost of service study. Heidell also updated MDU's marginal cost study with respect to distribution capacity costs.

175. Heidell agreed with Rosenberg that coincident peak demands are typically used in marginal cost studies to allocate demand-related generation, transmission, and substation costs. He acknowledged that it is appropriate to allocate demand-related generation and transmission costs differently in marginal and embedded cost studies, because their focuses are different. Marginal cost studies focus on the long-run marginal cost of a change in demand and efficient use of generation and transmission resources. Embedded cost studies focus on a number of objectives, including efficiency and equity.

176. In his original marginal cost study, Heidell allocated generation and transmission costs using the AED allocators MDU developed for its embedded cost of service study. In his rebuttal testimony he contended that allocating those costs using coincident peak demands has the effect of changing total marginal demand-related costs and total system marginal costs, and changes the amount of costs allocated to each rate class. However, these changes have no effect on MDU's proposed rates because MDU does not rely on the results of its marginal cost study to design rates in this case. He added that because marginal costs are independent of MDU's revenue requirement, allocating demand-related generation and transmission marginal costs using coincident peak demands does not affect the revenue requirement in this case.

177. Heidell explained that MDU prepared a marginal cost study in this case to satisfy PSC administrative rules and to inform rate design. He stated that if the PSC were to use the marginal cost study to establish rate class revenue responsibilities it would first be necessary to reconcile the marginal costs to the embedded costs, since it is typical for long-run system marginal costs to exceed the revenue requirement. He noted that, commonly, this is done through an equal percentage adjustment.

178. With respect to marginal distribution costs, Heidell explained that the discovery process revealed outdated distribution cost data. Current data reflects higher per-mile costs for underground and overhead circuits and more accurate customer counts. He stated that updating distribution cost data has minor impacts on the overall cost study results, a 0.4 percent increase

in total marginal costs. He stated that this change in his marginal cost study does not affect MDU's revenue requirement or rate design proposals.

179. Heidell provided several tables summarizing his modified marginal cost study on pages 8-10 of his testimony. The tables show that the above described modifications slightly increase the total marginal cost of serving the residential and small business rate classes and slightly reduce the total marginal cost of serving large commercial and industrial rate classes.

180. Heidell disagreed with Rosenberg's recommendation to use five monthly coincident peaks (three summer and two winter months) to allocate demand-related generation and transmission marginal costs. Heidell recommended using 12 monthly coincident peaks (12-CP) for transmission and transmission substation costs and the system coincident peak (1-CP) for generation costs. He testified that 1-CP should be used for generation because that approach is consistent with MDU's expectation that it will remain a summer peaking utility.

181. Heidell acknowledged that MDU's 2009 system peak demand appears to be atypical. However, he rejected the idea of trying to adjust that system peak using a load factor approach, as suggested by Rosenberg, because the data needed to adjust each rate class's peak were not readily available. He asserted approaches to weather-adjusting coincident peak demands should be studied for future cases if the PSC intends to rely on marginal costs for determining class revenue responsibility.

182. Heidell testified that allocating demand-related transmission and substation costs on the basis of 12-CP demand is reasonable given that 2009 was an atypical year and MISO uses a 12-CP allocator.

183. Heidell agreed with Rosenberg that the PSC could practically determine class revenue responsibility for transmission and distribution function costs based on embedded costs and generation function costs based on marginal costs, noting that there are virtually an infinite number of ways to spread the revenue requirement. However, he contended that Rosenberg's revenue allocation proposal does not promote efficiency because when marginal costs are reconciled to the revenue requirement, marginal cost-based prices are diluted. The result is a mix of embedded and marginal cost logic that obscures both short-run and long-run marginal costs.

184. Heidell defended his marginal energy cost estimates and disputed Rosenberg's contention that the definition of long-run marginal cost is incompatible with marginal energy

cost. According to Heidell, in the electric utility industry long-run marginal energy costs are typically calculated over multiple years for various applications, such as avoided cost analyses and general rate cases. These cost estimates are needed to evaluate trade-offs between different types of generation investments and the cost-effectiveness of conservation. His long-run marginal energy costs reflect the change in hourly dispatch costs due to an hourly increment in load over an eight year period. He asserted that it is appropriate to consider multiple years when estimating marginal energy costs if the context is a study of long-run marginal costs. He added that it would be inconsistent to mix short-term marginal energy costs with long-term marginal generation capacity, transmission, and distribution costs. He contended that his approach to estimating marginal energy costs is reflected in NARUC's *Electric Utility Cost Allocation Manual*.

185. Heidell disputed Rosenberg's testimony that designing rates based on long-run marginal energy costs would frustrate energy conservation. While Rosenberg suggested that investment in electric cars would be frustrated by prices reflecting long-run marginal energy cost, Heidell countered that consumers that are deciding whether to make long-term investments in electric cars or other conservation should consider long-term marginal energy costs. He adds that, in theory, designing rates based on long-run marginal costs provides customers with an appropriate price signal for evaluating investments that involve a trade-off of higher initial costs with lower reoccurring costs.

186. Heidell also disagreed with Rosenberg that designing rates to reflect long-run marginal energy costs would cause customers to pay twice due to the fuel and purchased power adjustment clause. Heidell pointed out that incorporating marginal costs into rate design influences how the revenue requirement is recovered but does not change either the total revenue requirement or the share of the revenue requirement allocated to each class. He also noted that the fuel and purchased power adjustment clause only recovers the difference between actual fuel costs and the expected fuel costs reflected in the revenue requirement.

187. Finally, Heidell explained that MDU provided marginal cost studies that include CO2 externality costs for informational purposes and the Company did not recommend using those studies to establish customer class revenue responsibility or rate design. However, Heidell disagreed with Rosenberg that using those marginal cost studies would increase rates. He reiterated that the marginal cost study does not impact the revenue requirement. He said that if

the PSC used those marginal cost studies in designing rates, energy rate components could increase but other rate components would decrease so that the total revenue would remain the same. He noted that adjusting rate components can affect individual customers within a rate class.

Darcy J. Neigum

188. Neigum said the 80-percent energy, 20-percent demand classification factor split that was originally assigned by MDU to its wind projects remains valid. He said that, based on actual operating data, MDU anticipates that both Diamond Willow and Cedar Hills will be assigned at least a 20 percent capacity allocation factor by MISO when it completes its generator-by-generator analysis.

189. Neigum did not agree with Rosenberg's calculation of a 32.8-percent energy, 67.2-percent demand split because, depending on the forecast for future energy and fuel prices and the amount of accumulated depreciation, Rosenberg's methodology could vary significantly over time and is not an accurate means to allocate the demand allocation split for wind investments.

190. According to Neigum, Rosenberg estimated the fuel savings associated with the Diamond Willow expansion and Cedar Hills but did not account for the fuel savings associated with the original Diamond Willow project. Thus, Neigum said the energy savings amount used by Rosenberg does not match up with the total revenue requirement that he used in his calculation.

191. Regarding MDU's proposed transmission cost recovery rider and Renewable Resource Rider, Neigum disagreed with Wilson's argument that the proposed riders do not have any offsets for likely reductions in other investment costs that are displaced by facilities whose costs are tracked. He noted that in the case of the Mandan Junction Substation there is no other substation that will be retired when Mandan Junction is placed into service. Neigum said the Diamond Willow and Cedar Hills wind projects are used to meet customer energy requirements that MDU would otherwise have purchased from the MISO Energy Market or generated from available MDU generation. He said the offsetting benefits of the renewable investments are passed through to the customer under the fuel and purchased power tracking adjustment or directly under the Renewable Resource Rider. Neigum asserted that transmission investments and tariff costs can provide direct benefits to customers in the form of congestion relief which

reduces the amount of fuel and purchased power that MDU would otherwise have to purchase. The corresponding savings flow back through the fuel and purchased power tracking adjustment.

192. Neigum did not agree with Wilson's contention that the cost trackers proposed by MDU in this docket are not optimal because they weaken and distort the incentives for cost minimization and they fail to recognize offsets to the costs being tracked. He contended the proposed riders would aid in avoiding single issue rate cases and they are only used with qualifying projects and costs as a temporary cost recovery mechanism until the next general rate case.

Encore Cross-Intervenor Response Testimony

Alan Rosenberg

193. Rosenberg objected to Wilson's "corrected" allocated cost of service study as having no basis in cost causation principles and as an unsupportable, transparent effort by Wilson to arrive at the conclusion that the residential customer class should not share in any rate increase. Rosenberg disagreed with Wilson's rejection of MDU's AED cost allocation method. He criticized Wilson's rationale for rejecting the AED method because its results are similar to those obtained by the CP demand allocation method. Rosenberg argued that if a widely accepted cost allocation method produces similar results to another reputable method, then it should be viewed as corroboration of the cost allocation method's results, not as a reason for rejection. Rosenberg contended that Wilson used incomplete and faulty information when presenting a comparison of cost allocation factors. Rosenberg countered with his own comparison of various allocators (AED, 5 CP, Wilson's, and pure energy) that showed the results of Wilson's method are very similar to those of the pure energy allocator.

194. Rosenberg pointed out that Wilson identified the "Average and Peak" and the "Equivalent Peaker" methods as methods that could be used to allocate generation plant costs, but Wilson did not use either of those allocation methods in his "corrected" study. Instead, according to Rosenberg, Wilson arbitrarily allocated generation plant by allocating 50 percent of plant on an energy basis and 50 percent on the average of the 12 coincident peaks. Rosenberg said Wilson justified his 50/50 demand/energy split by citing the legitimate capital substitution theory of cost classification and allocation; however, Rosenberg argued that Wilson oversimplified the concept by focusing on one aspect of the theory that says a utility substitutes capital costs in order to save fuel costs. Rosenberg contended that a utility actually seeks to

minimize its total costs – capital and fuel – and, therefore, the justification Wilson cited for his allocation of 50 percent of generation fixed costs on energy could be easily extended to allocate 50 percent of fuel costs on a demand basis. Rosenberg said Wilson's capital substitution argument also ignored the concept of a "break-even point," which is the point at which the fuel savings of a baseload plant just begin to offset the additional capital cost. He added that the capital substitution method assumes that high load factor customers should be allocated a larger portion of the baseload plant than warranted just on the basis of peak demand, but, correspondingly, those customers should be allocated a lower than system average fuel cost per kwh.

195. Rosenberg contended that Wilson's advocacy of his 50/50 methodology for cost allocation among customer classes is inconsistent with his acceptance of the 12-CP method for jurisdictional cost allocation. Regarding Wilson's allocation of demand-related generation fixed costs on a 12-CP basis, Rosenberg argued that his own recommendation to use a 5-CP method is preferable from the cost-causation standpoint.

196. Regarding transmission plants, Rosenberg objected to Wilson's proposal to allocate 50 percent of transmission costs on an energy basis as unreasonable since no portion of transmission costs is influenced by energy usage and because Wilson failed to provide support for his argument that transmission plants must be built to connect to baseload plants.

197. Rosenberg argued that Wilson provided scant justification for his proposal to classify distribution plant as 50 percent energy/50 percent demand-related. According to Rosenberg, distribution plant costs are not energy-related at all, but rather are customer- and demand-related. Rosenberg contended that Wilson is wrong to argue that the customer component should be zero and he disagreed with Wilson's objections to MDU's use of the widely accepted minimum-size method to estimate the portion of distribution plant costs that are customer-related.

198. Rosenberg claimed that Wilson's proposal to allocate A&G expenses based on retail revenues was unsupported and inappropriate because there are more relevant factors than revenues and MDU's approach is more consistent with regulatory guidelines.

199. Rosenberg presented a cost of service study he prepared that he said reflects Wilson's testimony on a customer component for distribution plant and is based on Wilson's Ex. JWW-10 with some modifications to eliminate what Rosenberg alleged to be errors by Wilson. (See Ex. AER-13.) According to Rosenberg, a comparison of this study's results to MDU's cost study in

this docket implies that rates for the Large General Service class are too high in both studies. Rosenberg ran the same study model again, but with generation plant allocated 100 percent to demand, which Rosenberg said is more conventional than Wilson's 50/50 method. (See Ex. AER-14.) Rosenberg argued that this cost of service study is reasonable and produces the most favorable results for residential and small general service customers, while showing that large customers should receive a smaller than average increase and should receive decreases if the result of this proceeding is a small enough overall rate increase. Rosenberg presented yet one more variation on Wilson's cost study model, which he termed a proxy cap-sub study (Ex. AER-15), that allocated 15 percent of generation fixed costs on the basis of total energy consumption as a proxy for allocating 50 percent on the basis of energy up to the break-even point. He said this study produced results similar to those in Ex. AER-14.

200. Regarding revenue distribution and Wilson's opinion that equal rates of return for each class should result from a cost of service study that correctly apportions total costs to each rate class, Rosenberg agreed, but noted that deference should be given to cost studies that are based on widely accepted methods and that the recommendations he made in his direct testimony for moderating rate increases are reasonable.

201. Rosenberg disagreed with Wilson's rate design proposals. First, regarding Wilson's recommendation that customer charges not be increased, he argued the result would be to unfairly overcharge large customers via demand and/or energy charges for any under-recovery of customer-related costs. He added that, even if one accepts Wilson's argument that under-recovery of the customer charge is needed to raise energy charges up to a sufficient level, the evidence in this docket implies that energy charges for the Large General Service class should be significantly reduced, not increased. For the same reason, Rosenberg disagreed with Wilson's recommendation that non-residential energy charges be increased if rate increases are in order for those customer classes. Finally, Rosenberg opposed Wilson's recommendation that the Commission not approve MDU's proposal to reduce summer energy charges for Large General Service customers. In response to Wilson's argument that the MDU proposal is unfair because the marginal cost at any specific time does not differ among customer classes, Rosenberg argued that classes with more concentrated usage in the higher cost periods have higher average marginal costs and, because the residential class does not pay demand charges, its energy charge must be set at a level to recover both demand- and energy-related costs. Rosenberg reiterated his

position that the current summer rates, and to a lesser degree the winter rates, for the large customers in the Rate 30 and Rate 35 classes are too high in relation to marginal cost and should be reduced.

Summary of Stipulation

202. MDU, MCC and Encore submitted a Stipulation that all parties agreed to as a fair and equitable resolution of the issues in this docket and several pending Fuel and Purchased Power Tracking dockets. A copy of the Stipulation without its appendices is attached to this Order as Attachment A. The terms of the proposed Stipulation are summarized as follows:

a. MDU will be granted an overall rate increase of $2,627,771 (a decrease of approximately $13,000 from current interim rates under Interim Order No. 7115b).

b. The parties present their agreed-upon revenue requirement to the Commission without attribution of any kind, and without a specified cost of equity capital, capital structure, or weighted cost of capital.

c. The annual rate increase will be allocated between customer classes and rate schedules as follows:

Customer Classes	Current Revenues	Proposed Revenue Change	Percent Change
Residential- Rate 10	$12,898,287	$644,914	5.00%
Total Small General	7,825,066	461,679	5.90%
Total Large General Rate 30	10,459,270	899,497	8.60%
TOD Large General Rate 31	655,025	58,952	9.00%
Rate 35	9,169,024	485,958	5.30%
Lighting – Rate 41	471,532	42,438	9.00%
Municipal Pumping – Rate 48	381,466	34,332	9.00%
Outdoor Lighting – Rate 52	320,127		0.00%
Total Montana Electric	$42,179,797	$2,627,770	6.23%

The reasonableness of the proposed revenue increase is dependent upon the above allocation of that revenue requirement being adopted by the Commission in its final order in this docket.

d. MDU will withdraw its proposal to modify the provisions of its Fuel and Purchased Power Cost Tracking Adjustment (Rate 58), other than to change the unit rate and base fuel cost in accordance with the existing adjustment mechanism. The resale margin level to be used in the adjustment mechanism shall be $101,000, the actual 2010 level.

e. MDU will withdraw its proposals for a Renewable Resource Cost Recovery Rider (proposed Rate 56) and a Transmission Cost Recovery Rider (proposed Rate 57).

f. MDU will be allowed to amortize over a period of 15 years, beginning with calendar year 2011, the Montana allocated share ($3,788,267) of the deferred generation costs associated with the development and subsequent abandonment of three proposed generation resources: Big Stone II, the Gascoyne Project, and Milton R. Young III. However, the unamortized portion of these deferred generation costs will not be included in rate base.

g. The Commission should issue final rate orders in the pending Fuel and Purchased Power Cost Tracking Adjustments under both Rate 35 and 58.

Commission Discussion and Findings of Fact

203. At the hearing on June 29, 2011, the parties made available several witnesses to support the Stipulation and for questioning by Commissioners and staff. The witnesses who testified were David Goodin, Darcy Neigum, Tammy Aberle, and Rita Mulkern for MDU; Alan Rosenberg for Encore; and John Wilson for MCC.

204. The majority of the hearing testimony was provided by Goodin who reiterated the major reasons for the rate increase application by MDU and why, in his opinion, it was a fair request (Tr. 22-24). He also noted that the Stipulation is "just and reasonable, reflecting the true cost of service to provide to our customers today." (Tr. 26)

205. Goodin also responded to several questions from Commission staff concerning the deferred generation costs to be allocated to Montana customers. Goodin testified that the Big Stone II project was, in the company's opinion, a "worthwhile project" and that MDU should be allowed to recover all its costs for the failed projects because the costs were "reasonable and prudently incurred" by MDU. (Tr. 29 and 31)

206. After review of the evidence in this matter, the Commission finds the Stipulation provides a reasonable settlement of the issues in this case. The Stipulation recognizes MDU's current revenues are insufficient but it provides for a considerably smaller revenue increase than the utility requested. MDU's Application (as revised in December 2010) requested an annual revenue increase of $4,939,830 for its electric utility. The Stipulation provides instead an increase of $2,627,771, which is a reduction of $2,312,059 from MDU's requested increase and will result in rates that are slightly less than the interim rates currently in effect. The

Stipulation's proposed allocation of the revenue requirement among the various customer classes is also reasonable.

207. As part of the Stipulation, MDU withdrew its proposals for two new cost recovery riders (proposed Rate 56 and Rate 57), which were opposed by both MCC and Encore.

208. The Stipulation allows MDU to amortize over 15 years (but not rate-base) the Montana-allocated share of its deferred generation costs. MDU had requested a 10-year amortization and rate-base inclusion of the deferred generation costs. The MCC disagreed with the rate-base inclusion but agreed with the 10-year amortization of the deferred generation costs. It is important to note that extension of the amortization period from 10 to 15 years will lessen the yearly customer rate impact of the cost recovery. In addition, by allowing MDU to recover its generation resource planning costs but not allowing for a return on those costs through rate-basing them, the Stipulation provides for appropriate risk sharing between MDU and its customers for generation resource planning activities and does not discourage MDU from undertaking those activities.

209. The Commission agrees with the parties' proposal in the Stipulation to approve on a final basis the Fuel and Purchased Power Cost tracking adjustments that have already been implemented on an interim basis in Dockets D2008.5.53, D2009.6.87, D2009.12.153, D2010.6.66, and D2010.11.109.

210. MDU unintentionally omitted from Appendix 1 of the Stipulation two proposed tariff schedules, Rate 13 (Optional Residential Electric Thermal Energy Storage) and Rate 100 (General Provisions). At hearing, neither Encore nor MCC objected to including Rates 13 and 100 in Appendix 1. The Commission approves including Rates 13 and 100 as proposed by MDU in Appendix 1.

211. The revenue requirement in the Stipulation is approximately $13,000 less annually than the revenue requirement contained in Interim Order No. 7115b. Normally, the difference would be rebated to customers with interest. In this case, however, the Commission finds that the amount that would be rebated -- estimated to be about $5,000 for the partial year the interim rates have been in effect – is immaterial and no rebate is required. In lieu of a rebate, the Commission directs MDU to remit $5,000 to the state Department of Revenue for deposit in the low-income energy assistance fund administered by the state Department of Health and Human Services to be used for the benefit of customers in MDU's electric service territory.

212. Any findings of fact that are properly conclusions of law are hereby adopted as such.

Conclusions of Law

1. MDU furnishes electric service for consumers in the State of Montana, and as such is a "public utility" under regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Montana Public Service Commission properly exercises jurisdiction over MDU's rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. Section 69-3-303, MCA, and Title 2, Chapter 4, MCA.

4. The rate levels, revenue allocations, and rate design proposed in the all-party Stipulation is in the public interest, and will result in just and reasonable rates as required by Section 69-3-201, MCA.

5. Any conclusions of law that are properly findings of fact are hereby adopted as such.

Order

1. The Commission approves the Stipulation submitted by MDU, MCC and Encore in its entirety as a reasonable settlement of the contested issues in this case.

2. The Commission authorizes as final the rates set forth in the tariffs appended to the Stipulation as Appendix 1, including Rates 13 and 100, effective for service rendered on and after XX, 2011.

3. MDU must file tariffs in compliance with this Order within 30 days of the service date of this Order.

4. As noted in Finding of Fact No. 211, MDU is not ordered to rebate the difference between the rates approved in the Interim Order and this Final Order. Rather, MDU must remit $5,000 to the state Department of Revenue for deposit in the low-income energy assistance fund administered by the state Department of Health and Human Services to be used for the benefit of customers in MDU's electric service territory.

DONE IN OPEN SESSION at Helena, Montana, on this 26th day of July, 2011 by a vote of 3 to 2.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

GAIL GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner
(Dissenting)

BRAD MOLNAR, Commissioner
(Dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.

ATTACHMENT A

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, CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service	REGULATORY DIVISION DOCKET NO. D2010.8.82
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2008.5.53
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2009.6.87
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment	DOCKET NO. D2010.6.66
IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	DOCKET NO. D2009.12.153
IN THE MATTER OF the Application of MONTANA-DAKOTA UTILITIES CO. for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment Rate 35	DOCKET NO. D2010.11.109

STIPULATION

COME NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota), the Montana Consumer Counsel (MCC), and, collectively, Encore Operating LP, ConocoPhillips, and Burlington Resources ("Encore and ConocoPhillips"), and agree and stipulate as follows:

1. On August 12, 2010, Montana-Dakota filed with the Commission an Application for authority to implement a general rate increase in the rates it is authorized to charge for electric service in Montana. The requested general rate increase was docketed as PSC Docket D2010.8.82.

2. The requested general rate increase, if granted in its entirety, would raise an additional $5,502,341 in annual revenues. Montana-Dakota also requested authority to modify its existing rate design. Included in the Application were requests for additional affirmative relief. Montana-Dakota proposed a Renewable Resource Cost Recovery Rider (proposed Rate 56), a Transmission Cost Recovery Rider (proposed Rate 57), and a modification of the Fuel and Purchased Power Tracking Adjustment (Rate 58). It also proposed the establishment of three new rate schedules (proposed Rates 13, 32, and 100), and the abolition of seven existing rate schedules (Rates 101, 102, 109, 114, 117, 122 and 130). All of the proposed changes in rate forms were set forth in proposed tariff sheets using legislative annotation and submitted as part of Appendix B to the Application.

3. The MCC intervened in the docket, opposing a rate increase of the magnitude requested by Montana-Dakota, the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, the proposed new rate riders, and some of the proposed changes in rate design.

4. Encore and ConocoPhillips intervened in the docket, opposing a rate increase of the magnitude requested by Montana-Dakota, the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, the proposed new rate riders, and some of the proposed changes in rate design.

5. The pre-filed testimony of the MCC expert witnesses was filed in this docket on December 17 and December 23, 2010. In that pre-filed testimony, the MCC concedes that Montana-Dakota has a revenue deficiency in the rates it is currently authorized to charge its Montana customers for electric service, but recommends an authorized rate increase of $583,696. The MCC also recommended rejection of the proposed new rate riders, and proposed an alternative allocation of the revenue deficiency between customer classes.

6. The pre-filed testimony of the Encore and ConocoPhillip's expert witnesses was filed in this docket on December 17, 2010. In that pre-filed testimony, Encore and ConocoPhillips concede that Montana-Dakota has a revenue deficiency in the rates it is currently authorized to charge its Montana customers for electric service, but recommends an authorized rate increase of $483,958. Encore also recommended rejection of the proposed new rate riders, and proposed an alternative allocation of the revenue deficiency between customer classes.

7. The revenue requirement presented by Montana-Dakota in this case included a weighted cost of capital of 8.778%, using the Company's actual capital structure and a cost of equity of 11.00%. The revenue requirements presented by the MCC, Encore and ConocoPhillips in this case included weighted costs of capital of between 72 and 78 Basis Points less than that developed by the Company. The MCC advocated that the cost of equity be set at 9.5%, while Encore and ConocoPhillips advocated that it be set at 9.6%.

8. On January 28, 2011, Montana-Dakota filed extensive rebuttal testimony in which it challenged the positions taken by the MCC, Encore and ConocoPhillips in this docket, including some of the mathematical calculations which were part of that advocacy.

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9. The Commission, on February 8, 2011 issued in this docket its Interim Rate Order 7155b. The Interim Rate Order authorized, during the pendency of this proceeding, an interim rate increase in the annual amount of $2,640,725. The interim rate increase is being collected through a separate line item on the bill reflecting a 6.28% increase in the amount billed for each rate component under each rate schedule, with the exception of the Fuel and Purchased Power Cost Tracking Adjustment.

10. For settlement purposes, a fair and equitable resolution of the issues in PSC Docket D2010.8.82 between Montana-Dakota, the MCC, Encore and ConocoPhillips, one which would result in the establishment of just and reasonable rates, would be as follows, and as further described in paragraphs 11 through 12 below:

A. Montana-Dakota should be authorized, in a final rate order entered in PSC Docket D2010.8.82, to a overall annual increase in the rates it is authorized to charge for electric service in Montana in the amount of $2,627,771 (a decrease of approximately $13,000 from current interim rates under Interim Rate Order 7155b), provided, the rate increase is spread between rate classes in conformity with Paragraph 10.C below.

B. Because of the substantial divergence between the respective parties, as set forth in their pre-filed testimony, in both their rate making methodologies, and the end results of those rate making methodologies, the parties present their agreed upon revenue requirement to the Commission without attribution of any kind, except as set forth in Paragraph 11, and without a specified cost of equity capital, capital structure, or weighted cost of capital.

C. The annual rate increase specified in Paragraph 10.A above should be allocated between customer classes and rate schedules as set forth in this subparagraph:

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Customer Classes	Current Revenues	Proposed Revenue Change	Percent Change
Residential - Rate 10	$12,898,287	$644,914	5.00%
Total Small General	7,825,066	461,679	5.90%
Total Large General Rate 30	10,459.270	899,497	8.60%
TOD Large General Rate 31	655,025	58,952	9.00%
Rate 35	9,169,024	485,958	5.30%
Lighting - Rate 41	471,532	42,438	9.00%
Municipal Pumping - Rate 48	381,466	34,332	9.00%
Outdoor Lighting - Rate 52	320,127	--	0.00%
Total Montana Electric	$42,179,797	$2,627.770	6.23%

The reasonableness of the proposed additional revenues set forth in Paragraph 10.A is dependent upon the interclass allocation of that revenue requirement, as set forth in this subparagraph, being adopted by the Commission in its final order in this docket.

D. In order to achieve the settlement of issues set forth in this Stipulation, Montana-Dakota will withdraw its proposal to modify the provisions of its Fuel and Purchased Power Cost Tracking Adjustment (Rate 58), other than to change the unit rate and base fuel cost in accordance with the existing adjustment mechanism. The resale margin level to be used in the adjustment mechanism shall be $101,000, the actual 2010 level.

E. In order to achieve the settlement of issues set forth in this Stipulation, Montana-Dakota will withdraw its proposal for a Renewable Resource Cost Recovery Rider (proposed Rate 56) and a Transmission Cost Recovery Rider (proposed Rate 57).

11. Montana-Dakota shall be allowed to amortize over a period of fifteen years, beginning with calendar year 2011, the Montana allocated share ($3,788,267) of the deferred generation costs associated with the development and subsequent abandonment of three proposed generation resources: Big Stone II, the Gascoyne Project, and Milton R. Young III.

However, the unamortized portion of these deferred generation costs will not be included in rate base.

12. Attached to this Stipulation as Appendix 1 are proposed tariffs implementing the various provisions of this Stipulation. If there is any conflict been the terms of this Stipulation and the proposed tariffs, the proposed tariffs control.

13. On November 30, 2009, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 35. The Application adjusted rates prospectively for the period January 1, 2010, through December 31, 2010, to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7055 to implement the rate change for the scheduled adjustment period.

14. On November 24, 2010, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 35. The Application adjusts rates prospectively for the period January 1, 2011, through December 31, 2011, to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7125 to implement the rate change for the scheduled adjustment period. Order 7125 effectively supercedes Order 7055 under the Rate 35 tracking adjustment mechanism.

15. On June 22, 2009, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 58. The Application adjusted rates prospectively for the period July 1, 2009 through June 30, 2010 to

capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Orders 7010 and 7011 to implement the rate change for the scheduled adjustment periods.

16. On June 22, 2010, Montana-Dakota filed an Application for Authority to Implement a Fuel and Purchased Power Cost Tracking Adjustment under Rate 58. The Application adjusted rates prospectively for the period July 1, 2010 through June 30, 2011 to capture both the estimated increase in fuel and purchased power expense, and to true up the balancing account for the previous adjustment period. The Commission issued Interim Rate Order 7094 to implement the rate change for the scheduled adjustment period. Order 7094 effectively supercedes Orders 7010 and 7011 under the Rate 58 tracking adjustment mechanism.

17. The parties agree that the Commission should issue final rate orders in the pending Fuel and Purchased Power Cost Tracking Adjustments under both Rate 35 and 58.

18. The Commission, after the completion of contested case proceedings in these dockets, should be moved in its discretion to issue a final order approving, adopting, and implementing the terms of this Stipulation and authorizing as final rates the tariffs set forth in Appendix 1, and finalizing the interim Fuel and Purchased Power Cost Tracking Adjustments pending in PSC Dockets D2008.8.53, D2009.6.87, D2010.6.66, D2009.12.153 and D2010.11.109.

19. The parties to this Stipulation present it to the Commission as a reasonable settlement of the issues raised in these dockets. No party's position in PSC Docket D2010.8.82 is accepted by the other parties by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession to any rate making principle, cost

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of service determination, or legal principle embodied, or arguably embodied, in this Stipulation.

20. The various provisions of this Stipulation are inseparable from the whole of the agreement between the parties to the Stipulation. The reasonableness of the proposed settlement set forth in this Stipulation is dependent upon its adoption, in its entirety, by the Commission. If the Commission decides not to adopt, in its entirety, the proposed settlement set forth in this Stipulation, then the entire Stipulation is null and void, no party to the Stipulation is bound by any provision of it, and it shall have no force or effect whatsoever.

21. The provisions of Paragraph 20 do not apply to the provisions of Paragraphs 13 through 19, as they relate to the Applications for Fuel and Purchased Power Cost Adjustment Cost Tracking Adjustments. Those provisions are separable from the other provisions of this Stipulation, and can be independently implemented by the Commission.

Dated this 4th day of May, 2011.

HUGHES, KELLNER, SULLIVAN & ALKE, PLLP

John Alke

John Alke
40 W. Lawrence, Suite A
P.O. Box 1166
Helena, MT 59624-1166

ATTORNEYS FOR MONTANA-DAKOTA UTILITIES

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Dated this 9th day of May, 2011.

MONTANA CONSUMER COUNSEL

Mary Wright

Mary Wright
111 N. Last Chance Gulch, Suite 1B
P.O. Box 201703
Helena, MT 5962-1703

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Dated this 9 day of May, 2011.

HOLLAND & HART, LLP

Thorvald A. Nelson
8390 E. Crescent Parkway, Suite 400
Greenwood Village, CO 80111

ATTORNEYS FOR ENCORE OPERATING LP; CONOCOPHILLIPS; AND BURLINGTON RESOURCES

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CERTIFICATE OF SERVICE

I hereby certify that a copy of FINAL ORDER issued in Docket Nos. D2010.8.82, D2008.5.53, D2009.6.87, D2009.12.153, D2010.6.66, and D2010.11.109 in the matter of Montana-Dakota Utilities Co. has today been served on all parties listed on the Commission's most recent service list, created 8/18/10, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: August 2, 2011

Donna Turkowski
For The Commission

Intervenors:

Burlington Resources

ConocoPhillips

Encore Operating LP

Montana Consumer Counsel

08/02/2011

Utility - Docket Service List

D2010.8.82

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ALBERT E CLARK	4868 EAST MICHIGAN ST UNIT 8 ORLANDO	FL	32812
DAVID E PETERSON CHESAPEAKE REGULATORY CONSULTANTS INC	10351 SOUTHERN MARYLAND BLVD SUITE 202 DUNKIRK	MD	20754-9500
JACK POUS DIVERSIFIED UTILITY CONSULTANTS	1912 W ANDERSON LN 202 AUSTIN	TX	78757-1266
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JOHN ALKE HUGHES KELLNER SULLIVAN & ALKE	40 W LAWRENCE SUITE A PO BOX 1166 HELENA	MT	59624-1166
JOHN W WILSON J W WILSON & ASSOCIATES	1601 N KENT STE 1104 ARLINGTON	VA	22209
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Utility - Docket Service List

D2010.8.82

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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **Case No. PU-10-124**
Electric Rate Increase
Application

ORDER ON SETTLEMENT

June 8, 2011

Appearances

Commissioners Tony Clark, Brian P. Kalk, and Kevin Cramer.

Daniel S. Kuntz, Associate General Counsel, MDU Resources Group, Inc., 918 East Divide Avenue, Bismarck, North Dakota, Attorneys for the Applicant MDU Resources Group.

Annette Bendish, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advocacy Staff through July 31, 2010.

Richard J. Savelkoul, Attorney, Felhaber Larson Fenlon & Vogt, 444 Cedar Street, Suite 2100, St. Paul, Minnesota, Public Service Commission Advocacy Staff from October 12, 2010.

Illona A. Jeffcoat-Sacco, General Counsel and Mark E. Gruman, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advisors.

Scott Skokos, Missouri Valley Resource Council, Suite 8, 103 - 1/2 South Third Street, Bismarck, North Dakota, for Intervenor Missouri Valley Resource Council.

James D. Roaché, 707 First Street Southwest, Crosby, North Dakota, Intervenor, appearing *pro se*.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882, as hearing officer.

Preliminary Statement

On April 19, 2010, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU) filed an application with the North Dakota Public Service Commission (Commission) seeking an annual revenue increase of $15,396,303 or 14 percent of total revenues.

On May 12, 2010, the Commission suspended the tariff revisions filed in MDU's Application.

On June 16, 2010 Advocacy Staff filed a Partial Settlement Agreement between MDU and Advocacy Staff relating to overall rate of return on MDU's rate base, including the return on equity component, for use in this proceeding. This Settlement Agreement was also received as MDU Exhibit 2.

Also on June 16, 2010, the Commission issued an Order on Interim Rates approving MDU's proposed interim rate increase.

Also on June 16, 2010, the Commission issued a Notice of Hearing and Notice of Public Input Sessions, scheduling public input sessions for July 12 and 13, 2010, and a formal hearing to begin November 8, 2010. The Notice specified the following issues to be considered:

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 July 6, 2010, MDU filed an amendment to its application eliminating from the application the Big Stone II generation development costs that were addressed in Case No. PU-09-733.

On July 12, 2010, and July 13, 2010, public input sessions were held via interactive television in Bismarck, Dickinson, and Williston, North Dakota.

On August 24, 2010, the Commission issued an Order granting the Petition to Intervene of James D. Roaché.

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On October 4, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Harvey A. Christian as a customer of MDU.

On October 25, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Missouri Valley Resource Council (MVRC).

On November 1, 2010, Scott Skokos filed a Petition to Practice Law Before the North Dakota Public Service Commission in Case No. PU-10-124 for permission to represent MVRC. On November 2, 2010, Scott Skokos filed an amended Petition to Practice Law Before the North Dakota Public Service Commission, and on November 5, 2010, Mr. Skokos filed a Second Amended Petition to Practice Before the North Dakota Public Service Commission.

On November 5, 2010, Harvey A. Christian advised the Administrative Law Judge that he was abandoning his intervention.

On November 8, 2010, in response to the petitions of Mr. Skokos, the Administrative Law Judge issued an Order Granting Petition to Practice before Commission.

On November 8, 2010, during the hearing, a second Partial Settlement Agreement between MDU and Advocacy Staff was received as MDU Exhibit No. 3.

The Commission held a hearing on the application on November 8, 9, 10, and 12, 2010, in the Commission Hearing Room.

On March 14, 2011, MDU filed a third partially executed settlement agreement executed by MDU and Advisory Staff. Attached to the March 14, 2011 settlement agreement was an Additional Wind Investment Analysis prepared by MDU.

On March 15, 2011, MVRC filed a copy of the Settlement Agreement executed by MVRC.

On March 24, 2011, the Commission issued a Notice of Hearing and Notice of Intent to Consider Information Not Presented at a Hearing. The Notice indicated that the Commission could consider the Investment Analysis submitted by MDU as an attachment to the Settlement Agreement filed the same day. The Notice set a hearing on May 5, 2011, and specified the following issue to be considered:

> Whether the Settlement Agreement should be approved and adopted by the Commission for the determination of MDU's application to increase it's rates for electric utility service?

On May 5, 2011, the Commission held a formal hearing to consider the third Settlement Agreement.

Also on May 5, 2011, a fully executed copy of the third settlement agreement was received as MDU Exhibit 29.

Discussion

MDU originally proposed to increase its rates for electric utility service to provide $15,396,303 additional annual revenue, or a 14 percent increase over current rates. The proposed increase was based on a 2010 test year, a 9.09 percent return on MDU's rate base, including a 12 percent return on the equity component. MDU identified the primary drivers of the need for a rate increase as increased investment in facilities, including Cedar Hills and Diamond Willow wind generation projects, and a significant loss of wholesale margins.

The interim rate increase implemented by MDU provides $7,617,000 additional annual revenue until final rates are approved by the Commission. The interim rate increased revenue from each customer class by approximately 7 percent and collected the increased revenue using an increased per KWh use charge.

MDU's July 2010 application amended its rate increase application, eliminating from the application the Big Stone II generation development costs that were settled in another case, Case No. PU-09-731. The July 2010 application amendment reduces MDU's proposed rate increase from $15,396,303 to $13,300,000.

In the June 2010 settlement agreement, MDU and Advocacy Staff recommend a 10.75 percent return on the equity component of cost of capital. They also recommend an earnings sharing mechanism by which MDU would refund to customers revenues corresponding to 50 percent of earnings above a 10.75 percent return on equity. The settlement of these matters would reduce MDU's proposed rate increase from $13,300,000 to $11,519,000.

The November 2010 settlement agreement between MDU and Advocacy Staff proposed an 8.736 percent overall rate of return on MDU's rate base and also proposed resolutions for issues regarding:

- Margin sales and sales for resale,
- Aircraft,
- Customer deposits,
- Maintenance costs for the Big Stone and Coyote generating facilities,
- Transmission WAPA costs,
- Storm damages,
- Deferred generation costs, treatment of costs associated with refinancing certain debt at lower interest rate,

- Labor costs,
- Accounting system and jurisdictional allocation process,
- Minimum standard rate case filing requirements, and
- Corporate allocation and affiliate transactions.

The November 2010 settlement would further reduce MDU's proposed rate increase from $11,519,000 to $10,299,000. Intervenor MVRC and Intervenor Jim Roaché did not sign this settlement.

MDU testimony at the November 8, 2010 hearing reflected additional adjustments of investment and expenses related to the wind generation projects. These adjustments would reduce MDU's proposed rate increase from $10,299,000 to $8,825,000.

The March 2011 settlement agreement between MDU, MVRC, and Advocacy Staff, along with the June 15, 2010 and November 8, 2010 settlement agreements, proposes the resolution of all contested issues in the rate proceeding. Intervenor Jim Roaché did not sign this settlement. The settlement recommends that MDU be allowed to file rates for electric utility service to provide an annual test year revenue increase of $7,614,000 or 6.9 percent. The settlement agreement proposes the resolution of additional issues regarding:

- Cedar Hills and Diamond Willow wind projects,
- Employee compensation,
- Board of Director's fees and expenses,
- Renewable energy credits,
- Rate design,
- Time-of-day rates, and
- Customer bill form.

The rate increase would be an approximately equal percent increase to each customer rate class. The rate impact for an individual customer in the residential rate class would vary dependent upon the customer's electric usage.

Having considered this matter, the Commission finds the June 2010, November 2010, and the March 2011 Settlement Agreements are reasonable and should be approved. The Commission finds the return on rate base and the return on equity component proposed by the March 2011 Settlement Agreement is reasonable, however, the environment in which utilities operate continues to change and the Commission intends to investigate the factors affecting return levels for North Dakota utilities and investigate market and regulatory changes that affect those factors.

MDU testified that it has an unfunded pension liability that may need to be addressed in a future rate proceeding. Given that possibility, the Commission provides the following thoughts so that the company can make decisions that align its interests with its customer service obligations.

1. A utility's rates must be just and reasonable. N.D.C.C. § 49-05-06. Just and reasonable rates must reflect only prudent costs. Prudent costs are those necessary and sufficient for efficient utility service. Those costs include the cost to attract and maintain a skilled workforce and costs associated with compliance with federal pension law.
2. Pension costs are affected by many factors. Some of these factors are within the utility's influence, including how it compensates its employees (e.g. salary levels; and the mix of salary, pension contributions and other benefits, including when and why it chose to move from defined benefit to defined contribution).
3. Other factors affecting pension costs are not within the utility's influence. These factors include the nation's economy, labor markets, stock market values and federal pension law.
4. The dividing line between factors within and outside the company's influence is not always clear. That lack of clarity complicates, but in no way eliminates, the Commission's obligation to ensure that the ratepayers bear only reasonable pension costs.
5. While just and reasonable rates may include only prudent costs, prudence does not guarantee cost recovery. There is no constitutional guarantee that a commission will include all prudent costs in rates. See Duquesne Light Co. v. Barasch, 488 U.S. 299, 307-16 (1989). It is lawful for a utility to bear some business uncertainties associated with prudent actions, because the utility's superior knowledge means it is in the best position to expose itself to these risks and manage them.
6. The Commission will apply these principles in reviewing any future utility request to reflect pension costs in rates. On making any such request, a utility should be prepared to:
    a. explain all causes of the unfunded liability;
    b. distinguish those factors over which it has influence, from those factors which are outside its influence;
    c. explain how it managed those factors over which it had influence;
    d. for those factors over which it did not have influence, explain how it anticipated those factors, what actions it took, both in advance and after the fact, to mitigate their effect; and
    e. explain to the commission its understanding of best practices in managing pension costs and how its actions compared to those best practices.

Having considered this matter, the Commission issues the following:

Order

1. The Settlement Agreements filed June 16, 2010, November 8, 2010 and March 15, 2011, a copy of each of which is attached to this Order, excluding the Additional Wind Investment Analysis that was attached to the March 15, 2011 Settlement Agreement, are made a part of this Order and are APPROVED.

2. MDU is authorized to implement an increase in its electric rates sufficient to produce a total annual revenue increase of not more than $7,614,000 in accordance with the rate design provided in the March 11, 2011 Settlement Agreement.

3. MDU shall file compliance tariffs consistent with this Order and the Settlement Agreements at least 30 days prior to the effective date of the rates.

PUBLIC SERVICE COMMISSION

Voting - Nay		
Kevin Cramer	**Tony Clark**	**Brian P. Kalk**
Commissioner	**Chairman**	**Commissioner**

MDU EXHIBIT 2

Public Service Commission
State of North Dakota

COMMISSIONERS

Kevin Cramer
Tony Clark
Brian P. Kalk

Executive Secretary
Darrell Nitschke

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June 16, 2010

Darrell Nitschke
Executive Secretary
600 East Boulevard, Dept 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed is a Partial Settlement Agreement reached between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. and the North Dakota Public Service Commission Advocacy Staff in the above proceedings.

The Parties ask the Commission to approve the Settlement Agreement and are available to provide any additional information the Commission may require.

Please contact us with any questions.

Sincerely,

Annette Bendish

Annette Bendish
Counsel for Advocacy Staff

Enclosure

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a
Division of MDU Resources Group, Inc.
Electric Rate Increase Application

Case No. PU-10-124

PARTIAL SETTLEMENT

This Partial Settlement is entered into this 15th day of June, 2010, by and between the North Dakota Public Service Commission advocacy staff ("Staff") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota"), (collectively, the "Parties"). This Partial Settlement sets forth the positions and recommendations of the Parties relating to the overall rate of return on the Company's rate base ("ROR"), including the return on equity ("ROE") component, for ratemaking purposes for the Company in the above-captioned proceeding. The Parties' recommendations are consistent with the public interest and will result in just and reasonable rates for the Company's retail electric operations in North Dakota.

TERMS OF SETTLEMENT

Reduced Return on Equity

The Parties agree that a 8.699 percent ROR is appropriate for determining the Company's revenue requirements in this proceeding. The Parties also agree to, and recommend the North Dakota Public Service Commission (the "Commission") approve in its final order, a ROE of 10.75 percent. The components of the recommended ROR are shown on Attachment 1 hereto.

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The reasonableness of an 8.699 percent ROR and 10.75 percent ROE are supported by various considerations, including but not limited to the following:

- The 8.699 percent ROR is less than the 8.8 percent ROR approved in the December 31, 2008 final order for Xcel Energy in its most recent electric rate case, Case No. PU-07-776, and is based on the same 10.75 percent ROE as approved in that case.
- The 8.699 percent ROR is only slightly greater than the 8.62 percent ROR, and is the same 10.75 percent ROE, as approved by the Commission in Otter Tail Power Company's recent electric rate case, Case No. PU-08-862.

Customer Refunds for Earnings Above Threshold

The Parties agree to, and recommend that the Commission approve, an earnings sharing mechanism that will result in customer refunds if the Company's net income from electric utility service in North Dakota exceeds a 10.75 percent ROE.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

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OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Partial Settlement is a negotiated Settlement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case and as required in tracking adjustment mechanisms that may be approved by the Commission, this Partial Settlement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Partial Settlement

It is understood and agreed that all offers of settlement and discussions related to this Partial Settlement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. This Partial Settlement shall not be deemed to prevent either the Staff or the Company from responding to positions taken by other intervenors in this proceeding; provided, however, that the Parties agree that such response shall not alter the positions and recommendations set forth in this Partial Settlement.

Effective Date

This Partial Settlement of Facts shall be effective as of the date hereof. It may be executed in counterparts.

Dated this 15th day of June, 2010.

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

By: ______________________
Dennis L. Haider
Executive Vice President – Regulatory,
Gas Supply and Business Development

Dated this 15th day of June, 2010.

North Dakota Public Service Commission Staff

By: ______________________
Annette M. Bendish
Counsel to Advocacy Staff

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ATTACHMENT 1

STIPULATED CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

	Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$280,502,591	42.232%	6.845%	2.891%
Short-Term Debt	20,829,409	3.136%	2.535%	0.079%
Preferred Stock	15,500,000	2.333%	4.590%	0.107%
Common Equity	347,368,141	52.299%	10.75%	5.622%
Total Capitalization	$664,200,141	100.000%		8.699%

MDU RESOURCES
GROUP, INC.
1200 West Century Avenue
Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000

Direct Dial No.
(701) 530-1016
(701) 530-1731 (fax)

March 11, 2011

Darrel Nitschke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed for filing are the original and seven copies of a Settlement Agreement between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., and the North Dakota Public Service Commission Advocacy Staff regarding the issues in the above-referenced proceeding. Montana-Dakota understands the Missouri River Resource Council is considering whether it will join the Settlement Agreement and will advise the Commission and parties upon reaching a decision. Mr. Roache' has previously indicated his opposition to the Settlement Agreement.

Attachment 1 to the Settlement Agreement consists of generation resource modeling information presented by Montana-Dakota Utilities Co. and considered by the parties during their settlement discussions. Attachment 1 is offered pursuant to N.D.C.C. § 28-32-25 solely for the purpose of the Commission's consideration of the Settlement Agreement. If the Commission determines to avail itself of the information presented in

167 PU-10-124 Filed 03/14/2011 Pages: 26
Settlement Agreement
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Daniel S. Kuntz

Attachment 1 in its consideration of the Settlement Agreement, Montana-Dakota will provide witnesses for examination and cross-examination regarding the information.

Sincerely,

Daniel S. Kuntz
Associate General Counsel

DSK/djv
Enclosure
cc: Ilona Jeffcoat-Sacco
Mike Diller
Jim Roche'
Scott Skokos

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
a Division of MDU Resources Group, Inc.
Electric Rate Increase Application

Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 11th day of March, 2011, by and among the North Dakota Public Service Commission Advocacy ("Staff"), Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Company") and Missouri Valley Resource Council (collectively the "Settlement Parties"). The Settlement Parties agree this Settlement Agreement, if approved by the Public Service Commission ("Commission"), in conjunction with the prior settlement agreements between Staff and Montana-Dakota, resolve the issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates in North Dakota to allow it to earn a reasonable return on equity.

Montana-Dakota's initial rate increase request was revised to $11,519,000 or approximately 10 percent, following a partial Settlement Agreement between the Company and Staff dated June 15, 2010. An interim rate increase of $7,617,000 or 7.04 percent was subsequently approved effective June 18, 2010.

Montana-Dakota identified the primary drivers for the need for its requested rate increase as increased investment in facilities, including the Cedar Hills and Diamond Willow wind generation projects, and the significant loss of wholesale sales margins.

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By Settlement Agreement dated June 15, 2010, Montana-Dakota and Staff agreed on the values for Cost of Debt, Return on Equity, and overall Rate of Return for purposes of determining a test year revenue requirement in this proceeding. The June 15, 2010 settlement agreement was modified by a settlement agreement dated November 8, 2010, which also resolved issues regarding: (1) margin sales and sales for resale; (2) aircraft; (3) customer deposits; (4) maintenance costs for the Big Stone and Coyote generating facilities; (5) transmission WAPA costs; (6) storm damages; (7) deferred generation costs; (8) treatment of costs associated with refinancing certain debt at lower interest rate; and (9) labor costs. The November 8 agreement also included provisions regarding issues to be addressed by Montana-Dakota prior to its next general rate case including a potential study to be completed by a mutually agreed upon independent consultant regarding Montana-Dakota's accounting system and jurisdictional allocation process, minimum standard rate case filing requirements, and corporate allocations and affiliate transactions. The settlement of these matters reduced the Company's request by $1,220,000. Montana-Dakota's resulting rate request after adjustment for the June 16, 2010 and November 8, 2010 partial settlements was $10,299,000.

Montana-Dakota's rebuttal testimony presented at hearing reflected additional adjustments of investment and expenses related to the wind generation projects as a result of the enactment of the Small Business Jobs Act on September 27, 2010; a reduction in the depreciation rate for the 2010 wind projects from 5.17 percent to 5.0 percent; and the correction of an error in the original filing related to accumulated deferred income taxes. These adjustments lowered the revenue requirement associated with the wind generation projects from $8,582,000 to $7,108,000. The total rate increase request, as effectively reduced by the settlements and adjustments for the wind projects, was $8,825,000 or 7.7 percent.

The Commission held a hearing on the Company's application on November 8-12, 2010, in the Commission Hearing Room. An Administrative Law Judge presided at the hearing. The Commission heard testimony regarding the proposed settlements as well as the remaining contested recommendations of the Staff to exclude from the Company's test year revenue requirement: (1) the investment and expenses associated with the Company's wind generation projects, (2) sixty percent of the Company's employee incentive compensation expenses, and (3) fifty percent of the Company's Board of Director's fees and expenses.

Following the filing of post-hearing briefs, the parties, as well as the Commission Advisory Staff, met for further settlement discussions. During those meetings the Company presented the results of generation resource modeling using the model and inputs that were used for development of the Company's 2009 Integrated Resource Plan ("IRP"). The modeling results presented by the Company provided a net present value comparison over 20 years of the difference between least cost generation resource scenarios, with and without the availability of the Big Stone II coal generation project, and scenarios in which the Diamond Willow and Cedar Hills wind generation projects were considered committed resources, also with and without the availability of the Big Stone II coal generation project. Upon request of the Staff, the Company provided additional modeling results after changing input values for market prices to test the sensitivity of the net present value differences to changes in market prices. The

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results of the modeling are attached hereto as Attachment 1. In each instance, the delta between the 20 year net present value of the least cost generation resource scenarios without the Big Stone II project (which has been cancelled) and generation resource scenarios with the Diamond Willow and Cedar Hills wind projects as committed resources was less than two percent (less than 3.5 percent with the Big Stone II generation project).

In consideration of the record evidence of this proceeding, the post-hearing arguments and briefs of the parties, the modeling results provided by the Company, and further discussions by the parties, the parties agree to the following subject to approval of this Settlement Agreement by the Commission:

1. Revenue Requirement Increase. The parties agree to final rates in this proceeding providing for an annual test year revenue requirement increase for the Company of $7,614,000 which equals that of the annual interim revenue requirement increase previously approved in this proceeding.

2. Rate Design. The Company shall file revised rates implementing the test year revenue requirement increase based upon the rate design principles and changes proposed by the Company, including the changes to the Thermal Energy Storage Rate 13 presented at the technical hearing and introduced as Exhibit MDU-26. The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement within 10 days after the issuance of a final order by the Commission.

3. Bill Form. Montana-Dakota will implement a new customer bill form with a target implementation date of December 31, 2012. This target date is subject to the

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Company's conversion to a new customer information and billing system, currently underway, that meets all necessary metrics for implementation. Updates will be provided to the Commission and Staff as implementation progresses with any known delays reported to the Commission in a timely manner.

4. Time of Day Rate Study. Montana-Dakota will confer with Staff and, following review and approval by Staff, issue a request for proposals ("RFP") for a study on the cost effectiveness of implementing mandatory time of day rates applicable to its North Dakota electric system customers. Montana-Dakota will review the RFP results with the Commission Staff along with the Company's recommendations. Upon approval by the Staff of the scope and cost of a study, Montana-Dakota will commission the time of day rate study. Montana-Dakota will be allowed to recover the cost of the study, as well as the cost of the study provided in the settlement agreement of November 8, 2010, to the extent the Company's 2011 ROE, after considering the cost of the studies, is less than 10.75 percent. The costs shall be recovered as a separate charge included in the Fuel Clause Adjustment Rate 58 over a one-year period. The costs shall be recovered on a per kwh basis and shall be calculated by dividing the appropriate costs by the projected kwh sales volumes for the period the charge shall be in effect.

5. Renewable Energy Credits. Montana-Dakota will allocate the December 31, 2010 renewable energy credit balance and all future generated renewable energy credits (RECs) to each jurisdiction based on the kwh jurisdictional allocation factor. Renewable energy credits allocated to North Dakota will be sold at the

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market price for the RECs with any proceeds flowed to customers through the Fuel Cost Adjustment Rate 58.

6. Basis of Settlement Agreement. It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

7. Effect of the Settlement Negotiations. It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

8. Applicability and Scope. This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in the Rate Design section of this Settlement Agreement.

9. Prior Settlements. The prior Settlement Agreements filed in this proceeding between the Company and Staff shall remain in effect and subject to approval by the Commission except to the extent modified by this Settlement Agreement.

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10. Modification. If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either the Company or the Staff files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

CONCLUSION

The Settlement Parties have agreed to the foregoing terms to resolve the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Settlement Parties, are in the public interest and will result in reasonable electric issues. For these reasons, the Settlement Parties urge the Commission to approve the Settlement Agreement.

Dated this 11th day of March 2011.

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

By: David L. Goodin
DAVID L. GOODIN
Title: PRESIDENT & CEO

Dated this 11th day of March 2011.

North Dakota Public Service Commission Staff

By: Mike Diller
Mike Diller
Dir. of Econ. Reg.

Missouri River Resource Council

By: ______________________

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Montana-Dakota Utilities Co.

Additional Wind Investment Analysis

North Dakota Rate Case No. PU-10-124

Overview

This additional analysis will look at the investments Montana-Dakota Utilities Co. (Montana-Dakota) made in Diamond Willow I, Diamond Willow II, and Cedar Hills to quantify the cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources, using the 2009 North Dakota Integrated Resource Plan (2009 IRP).

Study Methodology

This analysis utilizes the same computer modeling tool that Montana-Dakota used in the 2009 IRP. This modeling tool was developed by Electric Power Research Institute (EPRI) and is named Electric Generation Expansion Analysis System (EGEAS). EGEAS is a resource planning software package which optimizes future supply-side resource selections based on needs, available resources, and economic criteria.

The 2009 IRP model provides an evaluation of the Company's need and the economic conditions and alternatives that were available to Montana-Dakota at the time of the decision to invest in the Diamond Willow II and Cedar Hills Projects. In the 2009 IRP, Diamond Willow I was already in-service and Diamond Willow II and Cedar Hills were considered as committed resources in Montana-Dakota's least cost plan.

To perform the analysis, the 2009 IRP model was adjusted to remove the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects as in-service or committed resources. New site specific wind alternatives were created for the EGEAS model that reflected the actual installed costs of Diamond Willow I, Diamond Willow II, and Cedar Hills. Additional generic wind generation projects in 30 MW blocks were available for selection in the model based on original modeling assumptions. The site specific wind alternatives included in the model are contained in the following table.

Site Specific Wind Alternatives	**Size (MW)**	**Capital**	**Capital per kW**	**In-service Available**
Diamond Willow I	19.5	$39.4 Mill	$2,020	Jan. 2009
Diamond Willow II	10.5	$25.4 Mill	$2,419	June 2010
Cedar Hills	19.5	$47.4 Mill	$2,431	June 2010

All other model inputs from the 2009 IRP for existing, committed, and alternative resources remain unchanged and are contained in Attachment A. Midwest ISO energy prices in the EGEAS model used for the 2009 IRP were $60 per MWh on-peak and $40 per MWh off-peak escalated at three percent (3%) per year in 2008 Dollars.

Scenarios

Two different scenarios were modeled as part of this analysis. In the first scenario the EGEAS model developed the least cost plan based on available resources assuming all site specific wind alternatives were available resources to the model and not committed or in-service projects. The second scenario committed any site specific wind alternative projects not selected in the least cost plan to determine the cost differential over the least cost plan associated with the site specific wind alternative projects.

The 2009 IRP included the Big Stone II project as a committed least cost resource based on prior expansion analyses. Each of the two scenarios developed for this analysis were run with and without Big Stone II in the model to recognize that the Big Stone II resource is no longer available to Montana-Dakota's customers.

The EGEAS model optimizes investment and production costs over the study period and determines a net present value (NPV) for the model solution. For the 2009 IRP, a fifty (50) year study period was used to develop the least cost scenario. For this analysis the timeframe was reduced to a twenty (20) year period to reflect the life expectancy of the wind generation investments.

Results

- First Scenario
  - With Big Stone II - no wind projects selected
  - Without Big Stone II - Diamond Willow I selected

Case	Net Present Value*
With Big Stone II	$1,439.82 Mill
Without Big Stone II	$1,370.48 Mill

- Second Scenario
  - With Big Stone II – Diamond Willow I, Diamond Willow II, and Cedar Hills were committed resources to the least cost plan
  - Without Big Stone II – Diamond Willow II and Cedar Hills were committed to the least cost plan

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,481.72 Mill	2.9 %
Without Big Stone II	$1,386.85 Mill	1.2 %

*Net Present Value calculated over 20 years in 2008 Dollars.

A summary table of selected resources for both the First Scenario and Second Scenario is contained in Attachment B.

Analysis

The NPV numbers referenced in the results correspond to the entire Montana-Dakota integrated system and are not state specific. The NPV of production costs includes future operations and maintenance charges for all resources, fuel costs, market purchases, and recovery of future capital investments associated with the supply side resources.

As discussed in more detail in the Company's current North Dakota rate case; the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are currently in-service and are used and useful in providing electric service to Montana-Dakota's North Dakota customers. The purpose of this analysis is to show if there is a cost adder for renewable wind generation above Montana-Dakota's least cost resource plan.

With the Big Stone II project, none of the three site specific wind alternatives were picked in the least cost plan. It should be noted that under the normal fifty (50) year modeling period the NPV of the With Big Stone II case is less than the NPV of the Without Big Stone II case. The reason for this is that the investment benefit of a baseload coal-fired plant is received over the entire forty (40) plus year life of the asset which is not adequately reflected in a twenty (20) year study timeframe.

Montana-Dakota was ultimately unsuccessful in its attempts to develop the Big Stone II project and the Without Big Stone II scenario is the appropriate case to focus on for the additional cost of wind generation.

Under the Without Big Stone II modeling runs, the resource expansion model selects the Diamond Willow I project in the least cost plan. The incremental NPV cost to all state jurisdictions with the inclusion of Cedar Hills and Diamond Willow II in the Without Big Stone II runs is $16.37 million over the twenty (20) year life of the projects. This represents an increase of 1.2 percent over the least cost plan.

North Dakota's state jurisdictional share of the Cedar Hills and Diamond Willow II investments is approximately sixty-five percent (65%) which allocates $10.64 million of the NPV increase to North Dakota customers. The Cedar Hills project received a Certificate of Public Convenience and Necessity (CPCN) from the North Dakota Public Service Commission based upon estimated completion costs presented in the Company's application. The Cedar Hills project came in on budget and on schedule. The Cedar Hills wind project is rated at 19.5 MW and the Diamond Willow II project is rated at 10.5 MW for a total of 30 MW. Cedar Hills represents sixty-five percent (65%) of the total wind investment in the Cedar Hills and the Diamond Willow II projects. Therefore only thirty-five percent (35%) of North Dakota's share of the incremental NPV for wind generation should be considered a cost adder above the Without Big Stone II least cost plan which represents a NPV of $3.72 million. Using an eight percent (8%) discount rate and a twenty (20) year term, the annual levelized cost impact to North Dakota customers for Diamond Willow II is $379,000 per year.

This analysis does not include any benefit to North Dakota customers for the North Dakota earned investment tax credit for Cedar Hills or the additional bonus tax depreciation that was available in 2010 for Diamond Willow II or Cedar Hills.

Conclusion

The Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are used and useful in providing electric service to Montana-Dakota's customers and provide numerous benefits including: reduced dependency on market purchases, reduced exposure to market price fluctuations, zero marginal cost generation resources, and a fuel diversified generation fleet. The cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources is 1.2 percent.

Additional Modeling Runs

Additional modeling sensitivity runs requested by the North Dakota Public Service Commission Advocacy Staff are included in Attachment C. Additional sensitive runs looked at lower forecasted Midwest ISO energy market prices of $40 per MWh on-peak and $20 per MWh off-peak; and $50 per MWh on-peak and $30 per MWh off-peak. Also included in Attachment C are summaries of modeling runs to show the affects of using a 25 year depreciation life for the wind turbine investments versus the Company proposed 20 year depreciation life.

Attachment 1

Attachment A

Following tables are referenced from the 2009 IRP

Table A-1

Montana-Dakota's Existing Coal-Fired Units

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.75	20.20	2.25	1.14
Big Stone Unit I[3]	107.50	19.89	1.50	1.57
Heskett 1	27.96	50.57	5.98	1.59
Heskett 2	74.17	44.71	7.07	1.59
Lewis & Clark	52.30	43.55	2.47	1.13

1. Based on July URGE rating (1/1/08-10/31/09)
2. Montana-Dakota's 22.7% ownership share
3. Montana-Dakota's 25% ownership share

Table A-2

Montana-Dakota's Existing Natural Gas Combustion Turbines

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Glendive 1	36.0	9.48	2.35	6.90
Glendive 2	41.6	5.58	2.35	6.90
Miles City	24.5	9.06	2.35	6.90
Williston	9.6	3.08	2.35	6.90

1 – Based on July URGE rating (11/1/08-10/31/09)

Table A-3

Montana-Dakota's Existing Contracts, Variable Generation, and Diesel Unit

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	4.37	10.16	-27.23	-
Glendive Diesel	2.01	4.00	2.35	16.57
Glen Ullin Station 6	4.50	31.33	6.5	-
NSP contract[2]	95.00	17.70	84.30	-
NSP contract[3]	10.00	17.70	184.30	-
WAPA contract[4]	2.80	-	16.84	-

1. Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2. Increase to 100 MW in 2010 with option years in 2011-12.
3. Expires in 2010
4. Expires in 2020

Table A-4

Montana-Dakota's Committed Resources

Unit	In-Service Date	Summer Accredited Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU
Big Stone Unit II	2015	131.00	2938.59	29.84	1.80	1.66
WE Energies Contract	2012-2014	110-120	-	34.80	111.50	-
NSP Contract Extension	2011	105.00	-	21.00	77.50	-
Diamond Willow Addition[1]	2010	2.24	2400.00	10.16	-27.23	-
Cedar Hills Wind[1]	2010	4.37	2400.00	10.16	-28.77	-

1 - Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.

Table A-5

Resources Alternatives Available to Montana-Dakota

Unit	Size (MW)	Available Date	Capital Cost ($/kW)[2]	Fixed O&M ($/kW-year)[3]	Variable O&M ($/MWh)[3]	Fuel Cost ($/MBTU)
Combustion Turbine	43	2010	850	$11.63	$2.00	$6.90
Combustion Turbine	75	2010	750	$8.67	$2.00	$6.90
Combined Cycle	140	2010	1150	$12.50	$6.00	$6.90
Coal	blocks of 30	2013	3900	$48.00	$2.50	$1.50
Wind	blocks of 30	2009	2400	$23.33	$2.00	-
Wind before 2014[1]	blocks of 30	2013	2400	$23.33	-$27.23	-
Purchased Capacity	blocks of 10	2012	-	$34.80	$111.50	-

1 - Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2 - In 2008 dollars escalated at 7%
3- In 2008 dollars escalated at 4%

Attachment B

Summary Results for Additional Wind Analysis

Year	Scenario 1		Scenario 2	
	With Big Stone II	Without Big Stone II	With Big Stone II	Without Big Stone II
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT75	2-CT75 & CT43	CT75	2-CT75 & CT43
2016				
2017				
2018				
2019	CT43	CT43		CT43
2020				
2021			CT43	
2022				
2023		CT43		
2024	CT43			CT43
2025			CT43	
2026				
2027		CT43		
2028	CT43			CT43
NPV*	1,439.82	1,370.48	1,481.72	1,386.85

*Net Present Value (NPV) in millions of Dollars over 20 year study period
CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DWI – Diamond Willow I
DWII – Diamond Willow II
CH – Cedar Hills
Purchase – Purchased Capacity

Attachment C

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - No wind selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,410.12 Mill
Without Big Stone II	$1,314.64 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,458.68 Mill	3.4 %
Without Big Stone II	$1,337.89 Mill	1.8 %

*Net Present Value based over 20 years

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,427.35 Mill
Without Big Stone II	$1,345.79 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,472.34 Mill	3.2 %
Without Big Stone II	$1,364.87 Mill	1.4 %

*Net Present Value based over 20 years

25 Year Book Life

$40 & $60/MWh Market Prices

Results

On-Peak: $60/MWh in 2008 dollars escalated at 3%
Off-peak: $40/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,648.70 Mill
Without Big Stone II	$1,593.51 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,675.67 Mill	1.6 %
Without Big Stone II	$1,599.57 Mill	0.4 %

*Net Present Value based over 25 years

25 Year Book Life

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,614.40 Mill
Without Big Stone II	$1,529.05 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,648.99 Mill	2.1 %
Without Big Stone II	$1,541.03 Mill	0.8 %

*Net Present Value based over 25 years

25 Year Book Life

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,634.17 Mill
Without Big Stone II	$1,563.93 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,664.70 Mill	1.9 %
Without Big Stone II	$1,572.99 Mill	0.6 %

*Net Present Value based over 25 years

Summary Results for 25 year book life

Year	Scenario 1		Scenario 2	
	Big Stone II	No Big Stone II	Big Stone II	No Big Stone II
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT43	2-CT75 & CT43	BSP II & CT75	2-CT43 & CT75
2016	CT43			
2017				
2018				
2019		CT43		
2020				CT43
2021	CT43		CT43	
2022				
2023		CT75		
2024				
2025	CT43		CT43	CT43
2026				
2027				
2028				

CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DW I – Diamond Willow
DW II – Diamond Willow
CH – Cedar Hills
Purchase – Purchased Capacity

MDU EXHIBIT 3

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.,
Electric Rate Increase Application

Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 8th day of November, 2010, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff"), Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Montana-Dakota"). Montana-Dakota and Staff were not able to complete this Settlement Agreement timely, such that other parties were able to consider it. This Settlement Agreement resolves certain outstanding issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates to allow it to earn a reasonable return on equity.

Montana-Dakota sought to increase retail rates by $11,519,000, reflecting the Settlement Agreement dated June 16, 2010 or 10 percent. An interim rate increase of $7.6 million or 7 percent was approved effective June 18, 2010.

Montana-Dakota's electric operations in North Dakota were revenue deficient and earnings were below a reasonable return on equity ("ROE"). Montana-Dakota's last North Dakota general electric rate case was in 2003 with final rates effective January 2004.

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MDU Exhibit 3

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

In this current rate case, Montana-Dakota identified primary drivers for the need to request a rate increase as increased investment in facilities, including the expansion of wind generation in the Cedar Hills and Diamond Willow projects and the associated expenses and the significant loss of wholesale sales margin.

Montana-Dakota and Advocacy staff previously settled Cost of Debt, Return on Equity and overall Rate of Return, which are modified in this Settlement Agreement. Issues that remain disputed include handling of investments in wind generation and handling of incentive compensation and Board of Directors expenses.

Terms

The Parties agree to the provisions as defined below.

I. Rate Base and Revenue Requirements in the Rate Case.

The Parties agree with respect to the items discussed below. The agreement is made relative to the revised request amount of $11,519,000 and is net of Rate Base, ROR and Expense adjustments proposed by Staff. With respect to the settled items below, Staff proposed adjustment of $2,354,000, the Parties agree that Staff's proposed adjustment should be reduced to $1,220,000. This $1,220,000 will reduce the total request amount of $11,519,000. The parties do not agree how much of a reduction is necessary for Wind or Incentive Compensation and Board of Directors costs.

A) <u>Rate of Return.</u>

The Parties agree to a return on equity of 10.75 percent, with the capital structure and cost set forth in the table below:

Long Term Debt	41.084%	6.845%	2.812%
Short Term Debt	3.199%	2.535%	0.081%
Preferred Stock	2.380%	4.590%	0.109%
Common Equity	53.337%	10.750%	5.734%
Total	100.000%		8.736%

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Montana-Dakota agrees to share any earnings above 10.75 percent with customers (see Other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that an overall rate of return of 8.736 percent will be used for purposes of determining interim rates in Montana-Dakota's next electric rate case.

B) Resolved Issues.

Advocacy Staff's responsive testimony raised several issues of concern. As set forth below, the parties resolve all of the issues, with the exception of bonus and incentive compensation, Board of Directors expense and recovery of wind generation investment and related expenses. As stated above, the total agreed upon adjustment on agreed upon issues, net of Rate Base, ROR and expense items is $1,220,000. The parties have not agreed to an exact allocation of which issues are assigned specific adjustments, rather the parties agree to the reasonableness of the overall adjustment without allocation to specific items.

The non-monetary adjustments which have been agreed upon are covered herein, below.

Advocacy Staff's adjustment proposals included concerns and the Advocacy Staff requested adjustments on the following issues:

(1) Margin Sales and Sales for Resale. Advocacy Staff believed these were separate issues and requested a fixed amount be placed into the cost of service, based on 2009 actual wholesale sales margin. Montana-Dakota proposed to remove all wholesale sales margins from base rates and pass

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through 85% of the margins to customers via the Fuel and Purchased Power Adjustment Clause (FCA).

(2) *Aircraft.* Montana-Dakota sought recovery for its ownership in certain aircraft used for travel to service territory locations that are not provided with adequate commercial travel. Advocacy Staff challenged inclusion of the aircraft in rate base, as well as applicable expense items in Montana-Dakota's income statement. Montana-Dakota believes its investment is prudent and a legitimate cost of doing business.

(3) *Customer Deposits.* Advocacy Staff had concerns regarding MDU not using Customer Deposits as a reduction to rate base. Staff requested the jurisdictional amount, instead MDU provided both electric and gas combined balance. Montana-Dakota argues that customer deposits were not included as a reduction to rate base because interest is paid on customer deposits. Staff and Montana-Dakota agreed to include the Customer Deposits applicable to Electric service in the rate base and related interest expense in the cost of service.

(4) *Maintenance Costs for Big Stone and Coyote Generating Facilities.* Advocacy Staff had concerns about the unusually high maintenance costs included in the test year for the Big Stone and Coyote generating facilities. Montana-Dakota believes that if maintenance expenses are adjusted, the corresponding operation expenses should be treated the same way.

(5) *Transmission – WAPA Costs.* Advocacy Staff believed there was too high of a charge included for transmission and WAPA charges. Montana-Dakota did not object to the adjustment.

(6) *Storm Damages.* Advocacy Staff proposed Montana-Dakota be entitled to recovery for storm damages. Advocacy Staff requested that Major Storm Damages be tracked and accounted by the Company, so that from rate case to rate case it can be tracked and properly recovered. Advocacy Staff believes Montana-Dakota should be entitled to a normalized amount to cover costs of major storm damages. Montana-Dakota did not object to the adjustment.

(7) *Deferred Generation Costs.* Advocacy Staff believed Montana-Dakota should not be entitled to recover deferred generation costs that fall outside of the rate case. Montana-Dakota believes the deferred generation costs were prudently incurred and should be recovered. The Company applied for a deferred accounting order for these generation development costs.

(8) *Treatment of Costs Associated with Refinancing Certain Debt at Lower Interest Rates.* Advocacy Staff was supportive of recovery, but proposed modification as to how the Company recovered costs associated with refinancing debt. Montana-Dakota believes its treatment of the unamortized loss on debt and associated debt costs is in compliance with FERC accounting.

(9) *Labor Costs.* Advocacy Staff had concerns regarding the level of labor costs and compensation being included in the rate case, along with the

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methodology being used to calculate those costs for the test year. Montana-Dakota does not believe that Staff reflected current (2010) wage and salary levels in its adjustment.

C) <u>Wholesale Sales margins</u>

For purposes of determining the overall revenue requirement, the Parties agree to credit to customers through the FCA 100 percent of North Dakota's portion of asset-based margins received by Montana-Dakota. Passing these credits directly through the FCA as they are realized ensures that neither customers nor Montana-Dakota will be disadvantaged by a non-representative margin forecast in the test year. Montana-Dakota will, starting with the month final rates go in place, include in its fuel clause adjustment calculation, the actual amount of wholesale sales margins for the applicable month. Any balance of unrecovered Margin Sharing Adjustment (MSA) amount remaining at time final rates become effective will be recovered over a twelve month period based on forecasted kWh sales volumes and included in the FCA until fully recovered.

II. Issues to be Addressed before Montana-Dakota's Next Rate Case.

Montana-Dakota will meet with the Staff to discuss a potential study to be completed by the filing of the Company's next general rate case and to be conducted by a mutually agreeable independent consultant. The Company agrees to fund up to $125,000, or such other mutually agreeable amount, for such study. The scope of the study shall be agreed to by the parties but may include all or any of the following three major issues raised by the Staff in this proceeding:

1. Review Montana Dakota's Accounting System and the jurisdictional allocation process. One of the goals is, to determine if a better process can be developed to create an easier audit trail and a more transparent reporting process.
2. Develop an appropriate Minimum Standard Filing Requirements to facilitate a better review of Rate Case components in future cases. Staff will take the lead in identifying the standard information to be filed when requesting for a rate increase.
3. Review the corporate allocation process and the affiliate transactions used to allocate costs associated with MDU Resources and other affiliates to Montana-Dakota's gas and electric operations.

III. Allocations and Rate Design for the Rate Case.

The rate design shall be as Montana-Dakota proposed in its request, modified to reflect adjustments to the revenue requirement and class allocations described in this Agreement.

Montana-Dakota shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

IV. Other Terms and Conditions

A) <u>Customer Refunds for Earnings Above Authorized ROE.</u>

Per the settlement in Attachment A, the Parties agree to an earnings-sharing mechanism that will result in customer refunds if the Company's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

B) Deferred Generation Costs.

The Company shall be entitled to recover, outside of rate base, a $172,000 expense, for ten years. The parties agree that this amount will be included in expenses of future rate cases for ten years from the filing of this rate case. This amount is included in and not in addition to the settled amount discussed above.

C) Basis of Settlement Agreement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case, as required in tracking adjustment mechanisms that may be approved by the Commission, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

D) Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

E) Applicability and Scope.

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

F) Effective Date.

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve some of the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates.

For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

Dated this 8th day of November, 2010.

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

By: [signature]
Name and title
DAVID L. GOODIN
PRESIDENT + CEO

Dated this 8th day of November, 2010.

North Dakota Public Service Commission Staff

By: [signature]
Name and title
Attorney for
Commission Staff

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