Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_8-1065_1	Richard	Johnson	johnsonr@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Center90 South Seventh Street Minneapolis, MN 55402	Paper Service	No
OFF_SL_8-1065_1	Richard	Baudino	rbaudino@jkenn.com	J. Kennedy & Associates, Inc.	1347 Frye Road Westfield, NC 27053	Paper Service	No
OFF_SL_8-1065_1	Richard	Savelkoul	rsavelkoul@felhaber.com	Felhaber, Larson, Fenlon & Vogt, P.A.	444 Cedar St Ste 2100 St. Paul, MN 55101-2136	Paper Service	No
OFF_SL_8-1065_1	Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Avenue Minneapolis, MN 554022859	Paper Service	No
OFF_SL_8-1065_1	Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No
OFF_SL_8-1065_1	Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No
OFF_SL_8-1065_1	Ronald M.	Giteck	ron.giteck@state.mn.us	Office Of Attorney General	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No
OFF_SL_8-1065_1	SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No
OFF_SL_8-1065_1	Sharon	Ferguson	sharon.ferguson@state.mn.us	MN Department Of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes
OFF_SL_8-1065_1	Steve	Schneider	steve.schneider@ci.stpaul.mn.us	Board of Water Commissioners	1900 Rice Street St. Paul, MN 55113	Paper Service	No
OFF_SL_8-1065_1	Thomas G.	Koehler	tgk@ibew160.org	Local Union #160, I.B.E.W.	2522 Marshall Street, NE Minneapolis, MN 55418	Paper Service	No

Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_8-1065_1	Thomas L.	Osteraas	tomosteraas@excelsiorenergy.com	Excelsior Energy	Suite 305 11100 Wayzata Boulevard Minnetonka, MN 55305	Paper Service	No
OFF_SL_8-1065_1	Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	417 N 5th St Ste 200 Minneapolis, MN 554013206	Paper Service	No
OFF_SL_8-1065_1	Valerie	Means	valerie.means@state.mn.us	Office of the Attorney General	1400 BRM Tower445 Minnesota Street St. Paul, MN 55101	Electronic Service	No
OFF_SL_8-1065_1	Wade	Worthy	lwworthy@marathonoil.com	Marathon Petroleum Company LLC	PO Box 3128 Houston, TX 77253	Paper Service	No
OFF_SL_8-1065_1	William	Stamets	bill.stamets@state.mn.us	Office of the Attorney General	Suite 900445 Minnesota Street St. Paul, MN 551012127	Electronic Service	No
OFF_SL_8-1065_1	William J.	Hagstrom	william_hagstrom@catapult-llc.com	Catapult Capital Management LLC	32nd Floor 650 Fifth Avenue New York, NY 10019	Paper Service	No

Chris Nelson, Chair
Kristie Fiegen, Vice Chair
Gary Hanson, Commissioner

South Dakota
PUBLIC UTILITIES COMMISSION
500 East Capitol Avenue
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www.puc.sd.gov

Capitol Office
(605) 773-3201
1-866-757-6031 fax

Grain Warehouse
(605) 773-5280
(605) 773-3225 fax

Consumer Hotline
1-800-332-1782

May 8, 2012

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

Re: *In the Matter of the Application of Northern States Power Company dba Xcel Energy for Authority to Increase its Electric Rates*
Docket EL11-019

Ms. Van Gerpen:

Attached for filing please find the following:

- Joint Motion for Approval of Settlement Stipulation;
- Settlement Stipulation;
- Staff Memorandum; and
- Certificate of Service.

By copy of this correspondence, the foregoing is being served upon persons identified in the Commission's service list, this being intended as service by electronic mail. If you have any questions, please do not hesitate to contact me.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	)))))	**JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION** **EL11-019**

Northern States Power Company dba Xcel Energy (Xcel Energy) and the Staff of the South Dakota Public Utilities Commission (Commission Staff), jointly referred to as "Parties," hereby file the above-referenced Joint Motion and Settlement Stipulation with the South Dakota Public Utilities Commission (Commission). The Parties request the Commission adopt the attached Settlement Stipulation as the settlement and resolution of all issues subject to this proceeding except (i) cost recovery for the Nobles wind plant and the adjustments associated with the level of the Nobles wind plant cost recovery allowed, and (ii) rate of return on equity, cost of debt and capital structure. In support of this Motion, the Parties submit as follows:

1. This Joint Motion is made pursuant to ARSD 20:10:01:19.
2. The Settlement Stipulation represents a negotiated settlement and thereby resolves all issues subject to this proceeding except (i) cost recovery for the Nobles wind plant and the adjustments associated with the level of the Nobles wind plant cost recovery allowed, and (ii) rate of return on equity, cost of debt and capital structure.
3. The terms of the Settlement Stipulation agreed upon are just and reasonable, and consistent with South Dakota law.

WHEREFORE, for the foregoing reasons, the undersigned parties jointly request the Commission to: 1) adopt the attached Settlement Stipulation without modification for the purpose of resolving all issues subject to this proceeding except (i) cost recovery for the Nobles wind plant and the adjustments associated with the level of the Nobles wind plant cost recovery allowed, and (ii) rate of return on equity, cost of debt and capital structure, and 2) enter an Order finding that the attached Settlement Stipulation results in just and reasonable rates for Xcel Energy's customers in its South Dakota service territory.

Northern States Power Company
dba Xcel Energy

BY: Laura McCarten

Laura McCarten
Regional Vice President
Northern States Power Company
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

DATED: May 7, 2012

South Dakota Public Utilities
Commission

BY: Karen E. Cremer

Karen E. Cremer
Staff Attorney
State Capitol Building
500 E. Capitol
Pierre, SD 57501

DATED: 5/8/12

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**SETTLEMENT STIPULATION** **EL11-019**

I. SETTLEMENT STIPULATION

On June 30, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel Energy or Company) filed with the Public Utilities Commission (Commission) an application for approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.28% based on the Company's 2010 test year. In addition, Xcel Energy proposed to recover approximately $1 million of ongoing investments in its Monticello nuclear generating plant through a Nuclear Cost Recovery Rider intended to go into effect with final rates. Under the requested increase, a residential electric customer using 750 kWh per month would have seen an increase of 9.48%, or $6.93 per month. The proposed rates would potentially affect approximately 84,000 customers in Xcel Energy's South Dakota service territory. On January 2, 2012, Xcel Energy implemented an interim rate increase of approximately $12.7 million, subject to refund.

Commission Staff and Xcel Energy (jointly the Parties) held several negotiating sessions in an effort to arrive at a jointly acceptable resolution of this matter. As a result of those negotiations, the Parties have resolved all issues subject to this proceeding except (i) cost recovery for the Nobles wind plant and the adjustments associated with the level of the Nobles wind plant cost recovery allowed, and (ii) rate of return on equity, cost of debt, and capital structure. Although the Parties are unable to reach a resolution regarding these issues, and will notice these items for

Commission consideration, this Settlement Stipulation (Stipulation) addresses all issues other than those items in dispute related to the proposed rate increase. Because the revenue requirement will vary based on the Commission's resolution of these items in dispute, this Stipulation will set forth the range of the revenue requirement that will be established dependent on the Commission's final determination. The Commission's resolution of these contested issues, in combination with the items agreed to in this Stipulation, will determine the rates that result from this proceeding.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of settlement of those issues in Docket No. EL11-019 other than cost recovery for the Nobles wind plant and the adjustments associated with the level of Nobles wind plant cost recovery allowed, rate of return on equity, cost of debt, and capital structure. The Parties acknowledge that they may have differing views that justify the end result of the Stipulation, but each Party deems the end result to be just and reasonable. In light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Stipulation, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1. Upon execution of this Stipulation, the Parties shall immediately file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2. This Stipulation includes all terms of settlement other than cost recovery for the Nobles wind plant and the adjustments associated with the level of Nobles wind plant cost recovery allowed, rate of return on equity, cost

of debt, and capital structure. The Stipulation is filed conditioned on the understanding that, in the event the Commission imposes any changes in or conditions to this Stipulation, this Stipulation may, at the option of either Party, be withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose in this case or in any other proceeding before the Commission.

3. This Stipulation shall become binding upon execution by the Parties; provided however, if this Stipulation is withdrawn in accordance with Paragraph 2 above, it shall be null, void, and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; neither Party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; neither Party shall be deemed to have approved, accepted, agreed or consented to any ratemaking principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or either be advantaged or prejudiced or bound thereby in any other current or future proceeding before the Commission. Neither Party nor representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission accepting this Stipulation as precedent in any other current or future rate proceeding or any other proceeding before the Commission.

4. The Parties to this proceeding stipulate that all pre-filed testimony, exhibits, and workpapers on the settled issues be made a part of the record in this proceeding. The Parties understand that if the issues settled in this matter had not been settled, Commission Staff would have filed direct testimony on those issues, Xcel Energy would have filed rebuttal testimony

responding to certain of the positions contained in the testimony of Commission Staff, and an evidentiary hearing would have been conducted where the witnesses providing testimony on the settled issues would have been subject to examination.

5. It is understood that Commission Staff enters into this Stipulation for the benefit of Xcel Energy's South Dakota customers affected by this docket.

III. ELEMENTS OF THE STIPULATION

1. Revenue Requirement

The Parties agree that the final revenue requirement in this case will be dependent upon the Commission's decision resolving the contested issues.

a. The Parties agree on the rate treatment of a significant number of issues and that the treatment of settled issues is not dependent on the Commission's decision on the contested issues described above. However, the precise revenue requirement value of certain of the settled issues would be impacted by the Commission's decisions on the disputed issues of the Nobles Wind plant, rate of return on equity, cost of debt, and capital structure.

All recalculation necessary and resulting from Commission decisions on the disputed issues will be reflected in compliance with the Commission's Order after hearing. Additionally, parties agree there are five financial elements that cannot be determined until the final revenue requirement is known and those are the impact of Net Operating Loss, Cash Working Capital, Tax Collections Available, Weather Normalized Allocators, and Interest Synchronization. These recalculations will also be completed and presented for review in compliance with the Commission's Order after hearing.

b. The Parties agree that if the Commission adopts the position of Xcel Energy on all the contested issues, which assumes an overall rate of return of 8.52% and full cost recovery for the Nobles wind plant, the final revenue deficiency will be $11.886 million. The Company's rate of return is determined as shown in the rebuttal testimony of Company witness Mr. James M. Coyne and included here as Exhibit A.

c. The Parties agree that if the Commission adopts the position of Commission Staff on all the contested issues, which assumes an overall rate of return of 7.60% and 30% disallowance of the costs of the Nobles wind plant allocable to South Dakota, the final revenue deficiency will be $6.315 million. Staff's rate of return is determined as shown in the direct testimony of staff witness Mr. Basil L. Copeland Jr. and included here as Exhibit B.

2. <u>Tariffs</u>

Xcel Energy will submit tariffs through a compliance filing after the Commission renders a final decision on all matters in this case. The Parties agree that the final revenue requirement will be allocated to the affected rate classes as shown on attached Exhibit C.

3. Nobles Wind Plant

The level of cost recovery for the Nobles wind plant is disputed and presented in testimony to the Commission. As such, issues related to cost recovery and the associated impacts for energy, sales of emission allowances, federal production tax credits ("PTCs") and Renewable energy Credits will be determined by the Commission.

4. Asset and Non-Asset based Margins

South Dakota customers will be credited 100 percent of the jurisdictional portion of actual asset-based margins and 30 percent of the jurisdictional share of non-asset based margins from intersystem sales as described in the Company's South Dakota Fuel Clause Rider. For asset-based margins sharing, the Company agrees to continue to include a tracker in the monthly Fuel Clause Adjustment Reports showing the monthly amount credited to South Dakota customers. The Company will maintain a similar tracker for the non-asset based margins sharing credit. The retail share of the non-asset based margins will be computed annually after the close of the calendar year. The Company will provide both a fully allocated cost study and an incremental cost study showing the costs incurred to realize non-asset based margins in its next general rate filing.

5. Fuel Clause Rider Adjustments

a. The Company will credit to the Fuel Clause Rider any emission allowances allocable to the South Dakota jurisdiction that are sold on and after January 2, 2012.

b. The Company will credit PTCs related to wind production allocated to Xcel Energy South Dakota jurisdiction customers through the Fuel Clause Rider for PTCs earned on and after January 2, 2012.

c. Parties agree the Fuel Clause Rider Tariff will be modified to include the following language needed to allow emissions allowances and PTCs to flow through the fuel clause:

> "EMISSION ALLOWANCES AND FEDERAL PRODUCTION TAX CREDITS
> The South Dakota state jurisdictional share of revenue generated by the sale of emission allowances and the revenue requirements from federal production tax credits (PTC) associated with wind generation allocated to South Dakota shall be credited to customers."

7. MISO Schedule 26 Costs

The Parties agree that MISO Schedule 26 costs and revenues will be removed from base rates. The Parties agree the Commission will review the South Dakota jurisdictional portion of MISO Schedule 26 costs and revenues in the Transmission Cost Recovery Rider docket.

8. Amortization

The Parties agree that amortizations being recovered in rates under the terms of the Stipulation include the following where the cost will be deferred and amortized over the periods shown:

Item	Amount Amortized	Amortization Period	Annual Amount
	($)	(Years)	($)
Rate Case Expenses	340,000	3	113,333
Private Fuel Storage	1,010,000	6	168,000
Emission Sales Credit	(219,000)	5	(44,000)

a. Rate Case Expenses

The Parties agree that the unamortized actual rate case expense from Docket EL09-009 will be combined with the current Rate Case expenses and will be deferred and amortized over three (3) years. Further, the Parties agree that the average unamortized balance of $170,000 will be included as a component of other rate base. Section

III.7.b. of the Settlement Stipulation in Docket EL09-009 shall be null and void upon the approval of this Stipulation.

The Parties agree that the actual rate case costs incurred (excluding accruals) through March 31, 2012, is $178,000 and is included in the Rate Case Expense identified above. The Parties also agree that rate case expenses incurred after March 31, 2012, through the conclusion of this proceeding, will be deferred on the Company's balance sheet and reviewed for recovery in the Company's next general rate filing in South Dakota.

b. Private Fuel Storage ("PFS")

The Parties agree that the PFS deferred balance approved in EL09-009 of $1,010,000 to be amortized over 6 years in an amount of $168,000 annually will continue. Further, the Parties agree that the average unamortized balance of $505,000 will be included as a component of other rate base.

c. Emission Sales Credits

The Parties agree that the Emission Sales Credits deferred balance approved in EL09-009 of $(219,000) to be amortized over 5 years in an amount of $(44,000) annually will continue. Further, the Parties agree that the average unamortized balance of $(110,000) will be included as a component of other rate base.

d. Treatment of Amortizations in Future Proceedings

Parties acknowledge that the Company intends to file for a rate increase in 2012 and the annual amount of these amortizations will be included by the Company as a test year cost in that filing. The deferral accounting method and the resulting creation of a regulatory asset or deferred debit (the deferred balance) shall not preclude Commission review of these amounts for reasonableness for rate recovery in any future determination of rates, including both rate filings by the Company and rate reviews initiated by the Commission.

9. Nuclear Fuel Outage Costs.

In Docket EL07-035, the Commission approved Xcel Energy's petition to change from a direct-expense accounting to a deferral/amortization method and the resulting creation of a regulatory asset (the deferred balance) for planned refueling outages at the three nuclear plants. The Commission accepted this method of ratemaking treatment in the Company's last rate case, Docket EL09-009. It is agreed that this methodology is appropriate for ratemaking purposes in the present docket.

10. Service Reconnection Charge

The Parties agree that the service reconnection charge shall be set at $35.

11. Depreciation

The parties agreed to an adjustment for depreciation expense to restore generational equity and provide rate mitigation benefit for ratepayers in challenging economic conditions. This Settlement Stipulation reflects an adjustment for depreciation of $2,273,000. All depreciation expense reductions are based on changes to the annual depreciation expense accrual and are to be effective as of January 2, 2012.

This Stipulation is entered into this 8th day of May, 2012.

Northern States Power Co. d/b/a Xcel Energy	SD Public Utilities Commission Staff
BY: Laura McCarten	BY: Karen E. Cremer
Laura McCarten Regional Vice-President Northern States Power Company	Karen E. Cremer Staff Attorney South Dakota Public Utilities Commission
414 Nicollet Mall, 7th Floor Minneapolis, MN 55401	500 E. Capitol Avenue Pierre, SD 57501
DATED: May 7, 2012	DATED: 5/8/12

EL11-019
Settlement Stipulation
Exhibit A

Xcel Energy Proposed

Capital Structure and Cost of Capital

	Percent	Cost Rate	Weighted Cost
Common Equity	52.90%	10.65%	5.63%
Long-term debt	47.10%	6.13%	2.89%
Total Capitalization	100.00%		8.52%

EL11-019
Settlement Stipulation
Exhibit B

South Dakota Public Utilities Commission

Staff Proposed

Capital Structure and Cost of Capital

	Percent	Cost Rate	Weighted Cost
Common Equity	52.73%	9.00%	4.75%
Long-term debt	47.27%	6.02%	2.85%
Total Capitalization	100.00%		7.60%

Docket No. EL11-019
Settlement Agreement Exhibit C
Page 1 of 2

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Class Revenue at $11.886 Million Increase
Dollars in 000's

	Customer Classification	Average Customers (A)	Annual MWH Sales (B)	Test Year Present Revenue (C)	Final Revenue (D)	Increase (E)	Percent Increase (F)
1.	Residential	72,360	685,434	$65,920	$70,894	$4,974	7.54%
2.	C&I Non-Demand	7,309	100,732	$9,029	$9,710	$681	7.54%
3.	C&I Demand	3,106	1,184,129	$80,595	$86,676	$6,081	7.54%
4.	Lighting	164	13,498	$1,508	$1,622	$114	7.54%
5.	Retail	82,939	1,983,792	$157,052	$168,901	$11,850	7.54%
6.	Other Incr			$0	$36	$36	
7.	Total	82,939	1,983,792	$157,052	$168,938	$11,886	7.57%
8.							
9.	**Approximate Increases by Sub-Class**						
10.	**Residential**						
11.	Residential	72,167	682,462	$65,732	$70,691	$4,959	7.54%
12.	Resid Heat Pump	93	1,658	$111	$121	$9	8.49%
13.	Load Management	100	1,315	$77	$82	$5	6.87%
14.	**Res Total**	72,360	685,434	$65,920	$70,894	$4,974	7.54%
15.	**C&I - Non-Demand**						
16.	Small General	7,250	99,151	$8,911	$9,583	$672	7.54%
17.	Small General TOD	45	1,084	$85	$91	$6	6.95%
18.	Load Management	14	497	$30	$33	$3	9.55%
19.	**C&I N-D Total**	7,309	100,732	$9,026	$9,707	$681	7.55%
20.	**C&I - Demand**						
21.	General	2,845	627,421	$46,598	$50,200	$3,602	7.73%
22.	General TOD	147	342,678	$21,004	$22,460	$1,456	6.93%
23.	Peak-Controlled	73	59,842	$4,412	$4,790	$378	8.58%
24.	Peak-Controlled TOD	11	97,729	$5,488	$5,868	$380	6.92%
25	Energy-Controlled	30	56,457	$3,093	$3,357	$265	8.56%
26.	**C&I Dmd Total**	3,106	1,184,129	$80,595	$86,676	$6,081	7.54%
27.	**C&I Total**	10,415	1,284,860	$89,621	$6,762	$6,762	7.55%
28.	**Public Authorities**						
29.	Siren Service	-	-	$3	$3	$0	6.06%
30.	**PA Total**	-	-	$3	$3	$0	6.06%
31.	**Lighting**						
32.	System Service	-	1,706	$535	$621	$86	16.09%
33.	Energy	-	4,555	$312	$337	$24	7.78%
34.	Metered Energy	164	4,862	$341	$335	-$6	-1.68%
35.	Protective Lighting	-	2,376	$319	$329	$9	2.85%
36.	**Lighting Total**	164	13,498	$1,508	$1,622	$114	7.54%
37.	**Total Retail**	82,939	1,983,792	$157,052	$168,901	$11,850	7.54%
38.	Other Rev Increase				$36	$36	
39.	**Total Revenue**	82,939	1,983,792	$157,052	$168,938	$11,886	7.57%

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Class Revenue at $6.315 Million Increase
Dollars in 000's

	Customer Classification	Average Customers (A)	Annual MWH Sales (B)	Test Year Present Revenue (C)	Final Revenue (D)	Increase (E)	Percent Increase (F)
1.	Residential	72,360	685,434	$65,920	$68,556	$2,635	4.00%
2.	C&I Non-Demand	7,309	100,732	$9,029	$9,390	$361	4.00%
3.	C&I Demand	3,106	1,184,129	$80,595	$83,817	$3,222	4.00%
4.	Lighting	164	13,498	$1,508	$1,568	$60	4.00%
5.	Retail	82,939	1,983,792	$157,052	$163,330	$6,279	4.00%
6.	Other Incr			$0	$36	$36	
7.	Total	82,939	1,983,792	$157,052	$163,367	$6,315	4.02%
8.							
9.	**Approximate Increases by Sub-Class**						
10.	**Residential**						
11.	Residential	72,167	682,462	$65,732	$68,359	$2,627	4.00%
12.	Resid Heat Pump	93	1,658	$111	$117	$5	4.92%
13.	Load Management	100	1,315	$77	$80	$3	3.34%
14.	**Res Total**	72,360	685,434	$65,920	$68,556	$2,635	4.00%
15.	**C&I - Non-Demand**						
16.	Small General	7,250	99,151	$8,911	$9,267	$356	4.00%
17.	Small General TOD	45	1,084	$85	$88	$3	3.42%
18.	Load Management	14	497	$30	$32	$2	5.94%
19.	**C&I N-D Total**	7,309	100,732	$9,026	$9,387	$361	4.00%
20.	**C&I - Demand**						
21.	General	2,845	627,421	$46,598	$48,545	$1,946	4.18%
22.	General TOD	147	342,678	$21,004	$21,719	$715	3.40%
23.	Peak-Controlled	73	59,842	$4,412	$4,632	$220	5.00%
24.	Peak-Controlled TOD	11	97,729	$5,488	$5,674	$186	3.39%
25.	Energy-Controlled	30	56,457	$3,093	$3,247	$154	4.98%
26.	**C&I Dmd Total**	3,106	1,184,129	$80,595	$83,817	$3,222	4.00%
27.	**C&I Total**	10,415	1,284,860	$89,621	$3,583	$3,583	4.00%
28.	**Public Authorities**						
29.	Siren Service	-	-	$3	$3	$0	2.56%
30.	**PA Total**	-	-	$3	$3	$0	2.56%
31.	**Lighting**						
32.	System Service	-	1,706	$535	$601	$66	12.26%
33.	Energy	-	4,555	$312	$326	$13	4.22%
34.	Metered Energy	164	4,862	$341	$324	-$17	-4.92%
35.	Protective Lighting	-	2,376	$319	$318	-$2	-0.54%
36.	**Lighting Total**	164	13,498	$1,508	$1,568	$60	4.00%
37.	**Total Retail**	82,939	1,983,792	$157,052	$163,330	$6,279	4.00%
38.	Other Rev Increase				$36	$36	
39.	**Total Revenue**	82,939	1,983,792	$157,052	$163,367	$6,315	4.02%

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

**STAFF MEMORANDUM SUPPORTING
SETTLEMENT STIPULATION**

DOCKET EL11-019

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation of May 7, 2012, between Staff and Northern States Power Company (NSP or Company) in the above-captioned matter.

BACKGROUND

On June 30, 2011, the Company filed an application with the South Dakota Public Utilities Commission (Commission) seeking an increase in annual base rate revenues of approximately $14,583,000 or a 9.28 percent increase in retail revenue for electric service to customers in its South Dakota retail service territory. NSP is proposing to move the recovery of investments and expenses through the Transmission Cost Recovery (TCR) Rider and Environmental Cost Recovery (ECR) Rider into base rates. This shift in cost recovery is responsible for approximately $680,000 of the $14,583,000 revenue deficiency. The resulting increase in current charges to ratepayers is $13,903,000 or approximately 8.84%.

NSP's proposed increase was based on an historic test year ended December 31, 2010, adjusted for what NSP believes to be known and measurable changes, an 11.0 % return on common equity, and a 8.78 % overall rate of return on rate base. NSP witnesses submitted testimony stating that the increase is needed to: (1) maintain, improve, and replace infrastructure on its system; (2) manage cost increases related to general economic trends, at a time of expected reduced sales growth; and (3) comply with new and increasing regulatory requirements.

The Commission officially noticed NSP's filing on July 7, 2011, and set an intervention deadline of September 9, 2011. No petitions to intervene were filed. On July 20, 2011, the Commission issued an Order of Assessment of Filing Fee and Suspension of Imposition of Tariff. On November 4, 2011, the Company filed its Notice of Intent to Implement Interim Rates based on current rate design for service provided on and after January 2, 2012, pursuant to SDCL 49-34A-17. NSP implemented the interim rate increase at 8.09 percent or approximately $12,717,000, a level lower than the rate increase proposed in the initial application.

On March 13, 2012, after extensive discovery, Staff provided NSP a copy of its revenue requirement determination. Thereafter, Staff and NSP (jointly the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in NSP's rate filing. Ultimately, the Parties reached an agreement on all issues presented in the case except rate of return and the addition of the Nobles wind farm. The Parties are unable to reach a resolution regarding rate of return and the cost recovery of the Nobles wind farm and will notice these items for Commission consideration.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of NSP's filing and the information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in NSP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some Party positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues except rate of return and the addition of the Nobles wind farm. Staff believes the settlement is based on sound regulatory principles.

Staff and NSP agree NSP's revenue deficiency using Staff's litigation positions for rate of return and the Nobles wind farm is approximately $6,315,000 justifying an approximate 4.02% increase in retail revenue. The revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of NSP's South Dakota jurisdictional revenue requirement.

If the Commission were to accept NSP's litigation positions for rate of return and the Nobles wind farm, Staff and NSP agree NSP's revenue deficiency is $11,886,000 justifying an approximate 7.57% increase in retail revenue.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with December 31, 2010, total Company test year costs and allocates total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the December 31, 2010, test year results for known and measurable post-test year changes. Staff Exhibit___ (BAM-1), Schedule 3 illustrates Staff's determination of NSP's pro-forma operating income under present rates including Staff's litigation positions. Staff Exhibit___ (BAM-2), Schedule 2 illustrates Staff's calculation of NSP's South Dakota retail rate base including Staff's litigation positions, and Staff Exhibit___ (BAM-1), Schedule 2 and Staff Exhibit___ (BAM-2), Schedule 1 summarize the positions. Staff Exhibit___ (BAM-1), Schedule 1 supports NSP's revenue deficiency and total revenue requirement with Staff's litigation positions on rate of return and the Nobles wind farm.

Staff Exhibit___(BAM-4), Schedule 1 supports the revenue deficiency and total revenue requirement with NSP's litigation position for rate of return and the Nobles wind farm. Staff Exhibit___ (BAM-4), Schedule 3 illustrates Staff's determination of NSP's pro-forma operating income with NSP's litigation positions on the contested issues. Staff Exhibit___ (BAM-5), Schedule 2 illustrates Staff's calculation of NSP's South Dakota retail rate base using NSP's litigation positions. Staff Exhibit___ (BAM-4), Schedule 2 and Staff Exhibit___ (BAM-5), Schedule 1 summarize the positions. The adjustments in yellow on Exhibit___ (BAM-4), Schedule 3 and Exhibit___ (BAM-5), Schedule 2 identify the differences in the cost of service as a result of Staff's and NSP's litigation positions on rate of return and the Nobles wind farm.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average rate base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, December 31, 2009, through December 31, 2010.

SFAS 106 PAYGO – Prior to 1993, NSP and other companies accounted for post-retirement benefits other than pensions on a pay-as-you-go ("PAYGO") basis for both accounting and ratemaking purposes. Under the PAYGO method, the amount expensed on the Company's books matches the cost of the benefits provided during the year to retirees. In December 1992, the Financial Accounting Standards Board issued an accounting pronouncement, SFAS 106 – Accounting for Postretirement Benefits Other than Pensions, requiring public companies to account for postretirement benefits other than pensions on an accrual basis rather than PAYGO for financial reporting purposes. Following issuance of the accounting pronouncement, the Commission thoroughly examined the issue and decided to keep South Dakota utilities on the PAYGO accounting method for ratemaking purposes. Thus, in its filing, NSP adjusted its test year financial statements to reflect the PAYGO expense in its South Dakota operating results. The settlement accepts this adjustment.

Monticello Nuclear Plant Life Cycle Management/Extended Power Uprate (LCM/EPU) – The Company's rate filing included test year adjustments for 2011 capital expenditures supporting the Life Cycle Management/Extended Power Uprate (LCM/EPU) projects. Both projects have been approved by the MPUC; the NRC has approved the LCM project while the EPU is still under consideration. The settlement revises the Company's adjustment to reflect actual completed capital costs, accumulated depreciation, and accumulated deferred income taxes through the end of 2011. The adjustment decreases rate base by approximately $73,000.

Prairie Island Nuclear Plant Life Extension Projects – The Company requested test year adjustments for 2011 capital projects supporting the 20-year Prairie Island life extension granted by the NRC. The settlement revises the Company adjustment to reflect actual capital costs, accumulated depreciation, and accumulated deferred income taxes through the end of 2011. The updated life-extension project costs decrease rate base by approximately $598,000.

King Mercury – In Docket EL10-012, the Commission approved cost recovery for the revenue requirements associated with the King generating facility mercury control systems through the ECR Rider. The Company requested to shift cost recovery from the ECR rider to base rates by annualizing the investments and costs associated with the control system placed in-service during December 2010. The settlement accepts this adjustment.

Merricourt – NSP has cancelled a proposed wind project in Merricourt, ND and its rate filing eliminates all related costs. Because the project costs were recorded in the Construction Work In-Progress account that is not a component of rate base in South Dakota, the eliminations are limited to deferred taxes. The settlement accepts this adjustment.

Steam Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect extensions of the estimated remaining lives and changes in salvage values of four steam production plants – Black Dog Units 3 and 4, Sherco Unit 3, and the refuse-fueled Red Wing and Wilmarth plants. The settlement accepts this adjustment.

Other Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect reductions in the estimated remaining lives and changes in salvage values of two additional steam production plants – Inver Hills and Riverside. The settlement accepts this adjustment.

Bonus Tax Depreciation – The Tax Relief Act of 2010, which was signed into law in December 2010, extended the "bonus" depreciation tax deduction allowance and allowed for a 100 percent bonus tax depreciation for certain projects placed into service from September 9, 2010, through December 31, 2011. The guidelines issued following enactment of the Tax Relief Act contained provisions that required different treatment for certain items during 2010 than what NSP had reflected on its books. Therefore, it was necessary for NSP to adjust its 2010 financial statements to reflect the new tax guidelines. The settlement accepts the adjustment.

Net Operating Loss - The tax deduction allowance that a utility receives for depreciating a newly acquired asset exceeds the book depreciation expense allowance. This is because an asset is generally depreciated on a straight-line basis over its useful life for financial reporting purposes, but the IRS allows an accelerated depreciation allowance for income tax purposes. While the utility's current tax expense is immediately reduced because of tax depreciation, the utility is required to "normalize" the tax effect of the difference between tax and book depreciation by recording a "deferred tax expense". In this manner, the benefit of tax depreciation is spread over the depreciable life of the asset. Until the asset is retired, however, rate base is reduced by the amount of accumulated deferred taxes.

Primarily because of the 50% and 100% bonus depreciation allowances that have been authorized by Congress over the past couple of years, NSP's tax deductions exceeded its income in 2010 and resulted in a net operating loss for the utility. That is, NSP had tax deductions that it could not use to offset income generated in 2010. It would be unreasonable to credit ratepayers for the increase in accumulated deferred taxes if NSP could not use the tax deduction. NSP, however, will be allowed to carry-forward the unused tax deduction to offset income it generates in future years. Therefore, an adjustment is necessary to reduce the accumulated deferred tax balance to remove the effect of the bonus depreciation tax deductions that NSP could not utilize because of the net operating loss. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma income that is generated by the rate increase and expenses authorized by the Commission in this rate case. Therefore, the precise value of net operating loss adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case, including the rate of return and Nobles Wind Farm issues that are set for hearing.

Chisago Transmission Line – The Company proposed to remove the Chisago transmission project from the test year as part of its *Remove Riders* adjustment on Exhibit___(TEK-1), Schedule 6a, column 12 and Exhibit___(TEK-1), Schedule 6b, column 34. The Company requested cost recovery of the Chisago transmission project in the pending TCR filing, Docket EL12-035. Since the Chisago transmission project was placed in-service during the latter half of 2010 and a full year of costs and revenues cannot be accurately reflected in the test year, the Company proposed to collect the revenue requirements associated with the Chisago transmission project through the TCR filing. The settlement accepts this adjustment.

Cash Working Capital – The settlement determination modifies NSP's working capital claim by: 1. Including net payment leads and lags for interest on long term debt, depreciation expense, investment tax credit, and deferred income taxes; 2. Modifying lead days to reflect statutory payment dates rather than actual payment dates; 3. Correcting a transposition error regarding the revenue lag and expense lead days for interchange revenues and expenses; 4. Separately identifying the expense lead days for vacation pay; and 5. Recognizing the payment lags associated with tax collections available from sales tax related to the revenue deficiency and employee contributed FICA and federal withholding taxes. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma revenues and expenses that will not be known until the Commission makes a final determination on all of the issues in the case. Therefore, the precise value of the cash working capital adjustment cannot be quantified at this time.

Fox Lake Transmission Line – The Company sold the Lakefield Junction – Fox Lake transmission line (Fox Lake Transmission Line) to ITC Midwest on January 7, 2011. There was no gain or loss as a result of this transaction. This asset was improperly included in the test year as the transmission line is no longer owned by NSP. The settlement determination removes the revenue requirements associated with the Fox Lake Transmission Line. The adjustment decreases rate base by approximately $715,000.

Docket EL09-009 Amortizations – In the Settlement Stipulation approved in Docket EL09-009, the Commission authorized a six year amortization period for the Private Spent Fuel Storage Facility and a five year amortization period for SO2 emission allowance sales. Since the Company filed a rate case within two years of the date rates were implemented, those costs have not been fully amortized. The Company included the 13 point end of month average for the unamortized expenses from December 2009 to December 2010 as a component of other rate base in the test year. The Settlement Stipulation approved in Docket EL09-009 allows the average unamortized balances to be included as a component of other rate base until the costs are fully amortized. The settlement reflects the average unamortized balances as stipulated, decreasing rate base by approximately $336,000.

Depreciation to Reflect 2012 Rates – In a late 2011 Minnesota rate settlement, NSP agreed to numerous adjustments to production, transmission, and distribution depreciation rates based upon an extensive review with the objective of "restoring intergenerational equity and providing rate mitigation benefits to consumers". Also, the Company anticipates that these rates will be supported by the periodic, five-year depreciation study it will file with the MPUC in July 2012. The rate settlement was approved by the presiding Minnesota Administrative Law Judge on February 22, and, with minor modifications, by the MPUC on March 29, 2012. The settlement reflects the application of these Company-supported rates to plant assigned or allocated to South Dakota during the test year. The effect of these changes is to increase rate base by one-half of the $2,273,000 reduction in depreciation expenses, or approximately $1,137,000.

Rate Case Expense – Rate case expense from Docket EL09-009 was amortized over a five year period beginning January 18, 2010. Interim rates in this case were put into effect on January 3, 2012, leaving approximately three more years of cost recovery until the expenses are completely amortized. The Company included the 13 month average, from December 2009 to December 2010, for the unamortized rate case expense from Docket EL09-009 as a component of other rate base in the test year. The settlement reflects the average unamortized balance of rate case expense from Docket EL09-009.

In this proceeding, NSP proposed to amortize $388,100 of direct expenses over a two year period. The Company did not request rate base treatment of the unamortized balance. The settlement allows the average unamortized balance of actual rate case expense through March 31, 2012, as an addition to rate base. The net effect of these changes reduces rate base by approximately $73,000.

Working Capital Updates – The settlement reflects the most recent 13-month average for materials and supplies, fuel stocks, prepayments, and customer advances. The net effect of these changes increases rate base by approximately $578,000.

Monticello "No Single Event" Capital Project - During discovery, the Company proposed an adjustment for a capital addition to the Monticello nuclear unit that was not included in the original application. The No Single Event capital project was placed in-service during July 2011 and was designed to meet the requirements of the "no single act" portions of the NRC's rule change to 10 CFR 73.55, "Requirements for Physical

Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage". Specifically, under Section 73.55 (i), "Detection and assessment systems", subsection (4):

> *Both alarm must be designed and equipped to ensure that a single act cannot disable both alarm stations prior to detection.*

The capital additions necessary to comply with this provision included:

- Constructing a new search train entrance building and extending out the protected area boundary;
- Installing a new search train building of typical frame style construction along the new protected area perimeter;
- Relocating and/or adding new detection & assessment equipment, including PIDs, microwave, protected area lighting, cameras & poles, cable & conduit, and gates to support the new protected area boundary;
- Relocating the existing search train equipment to the new search train entrance building; and
- Placing the current search train area in an acceptable condition for future remodeling efforts.

The settlement accepts this adjustment as this capital project was necessary to comply with federal law, is non-revenue producing, and qualifies as a known and measurable adjustment. The adjustment increases rate base by approximately $194,000.

Weather Normalized Allocator – The Company proposed an adjustment to reflect the impact on expenses due to the difference between weather normalized demand and energy allocators and actual demand and energy allocators. The settlement revises this adjustment to reflect the rate base portion of the adjustment on the rate base schedules as opposed to including an estimate of the rate base impact as a part of the operating expense adjustment. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma investments, revenues and expenses that are allocated to the South Dakota retail jurisdiction based on energy and demand. Therefore, the precise value of the weather normalized allocator adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Depreciation Annualization – During discovery, the Company proposed an adjustment to modify the depreciation expense included in the test year from three nuclear plant adjustments. The Monticello LCM/EPU, Prairie Island Life Extension, and Monticello "No Single Event" plant adjustments all included the actual 2011 depreciation expense in the test year. NSP proposed to reflect a full year of depreciation expense based on the actual investment cost. The settlement accepts this adjustment, decreasing rate base by approximately $171,000.

OPERATING INCOME

Weather Normalization – The Company proposed an adjustment to 2010 test year sales and revenues to reflect normal weather based on the 20 year moving average of historical heating degree day (HDD) and temperature humidity index (THI) data. The settlement revises the Company's adjustment to: 1. Calculate the weather effect from heating based on the 30 year National Oceanic and Atmospheric Administration (NOAA) HDD normals developed using the thirty-year period, 1981-2010; 2. Calculate the weather effect from cooling based on normal THI scaled to reflect 30 year NOAA normals by using the ratio of actual CDDs to normal CDDs per NOAA applied to the actual THI; and 3. Include an adjustment to test year fuel expenses. The details for this adjustment can be found on Exhibit_(BAM-3), Schedules 1 through 3. The net effect of these changes reduces operating revenues by approximately $167,000 and reduces operating expenses by approximately $488,000.

Fuel Lag - The Company proposed an adjustment to adjust test year revenues and expenses to an actual 2010 calendar-month basis, eliminating the recovery lag of approximately 2.5 months. The settlement accepts this adjustment.

Fuel Recovery Timing – The Company proposed an increase to operating revenues to reflect the January 2011 accrual reversal of unbilled deferred fuel cost revenues. In September 2010, the Company began accruing revenue for the unbilled deferred fuel cost at the end of the month and recording an accrual reversal at the beginning of the following month. The fuel recovery timing adjustment reflects the January 2011 accrual reversal corresponding to the December 2010 accrual included in the test year. The settlement accepts this adjustment.

Incentive Compensation – The Company proposed an adjustment to eliminate three of the four incentive plans from the test year. The one incentive plan which NSP seeks cost recovery, Annual Incentive Program (AIP), has many performance targets related to corporate, business area, and individual employee performance. The test year AIP amount was revised to reflect a four year average of costs from 2007 through 2010 using a factor based on the differential between targeted compensation and actual payouts.

Staff's primary concern regarding incentive compensation plans relates to the use of financial targets as the threshold for plan payouts. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation. The settlement modifies NSP's incentive compensation costs by (1) normalizing AIP costs based on actual payouts for performance indicators other than financial for the period of 2007 through 2010; (2) removing AIP compensation paid to non-exempt employees who are no longer eligible for incentive compensation; and (3) including payouts related to four of the nine Environmental Plan targets that were eliminated in the Company's original filing. The net effect of these changes reduces operating expenses by approximately $655,000.

Vegetation Management – The Company proposed to normalize vegetation management expense using a five year average of actual experience from 2006 through

2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment reduces operating expenses by approximately $36,000.

Storm Damage – The Company proposed to normalize storm damage expense using a five year average of actual experience from 2006 through 2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment increases operating expenses by approximately $8,000.

Claims and Injury Compensation – The Company proposed to normalize claims and injury compensation expense using a five year average of actual experience from 2006 through 2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment increases operating expenses by approximately $64,000.

Fuel Expense Write-Off - In 2010, the Company discovered its deferred fuel methodology was incorrect and the balance sheet calculated too large of an asset which had gradually built up over time. To correct the over-stated asset, the Company recorded a write-off to expense in the amount of the excess deferred fuel balance. This adjustment removes this one-time write-off from the test year. The settlement accepts this adjustment.

Advertising – The Company proposed to remove promotional advertisements from the test year. The settlement accepts this adjustment and removes the advertising expenses related to 1. Two advertisements that were erroneously included; 2. The saver switch program that is collected through the Demand Side Management Cost Recovery Tariff; and 3. NSP's 2010 Supplier Diversity Campaign as the advertisements' primary purpose is to enhance the image of the Company. The net effect of these changes reduces operating expenses by approximately $7,000.

Economic Development – The Company proposed to continue the current economic development plan approved by the Commission in the amount of $100,000 shared equally between ratepayers and shareholders. The settlement reflects the continuance of the current plan approved by the Commission.

Interest on Customer Deposits - The Company proposed an adjustment to reflect the interest paid on customer deposits as an expense along with the corresponding reduction to rate base recognizing that customers supplied these funds as opposed to investors. The settlement accepts this adjustment.

Association Dues – The Company proposed an adjustment to remove dues that included a component for lobbying and social activities of the organization. The settlement accepts this adjustment, corrects an error in calculating the dues to exclude, and eliminates dues paid to organizations which promote social and economic development activities. Please see Exhibit___(MAT-1), Schedule 2 for details. The net effect of these changes reduces operating expenses by approximately $7,000.

SFAS 106 PAYGO – Please see the SFAS 106 PAYGO explanation in the Rate Base section. The settlement accepts this adjustment.

Rate Case Expense – In this proceeding, NSP proposed to amortize $388,100 of direct expenses over a two year period. The Company proposed using a two year amortization period to reflect the anticipated time period until the next rate case filing. Although NSP's proposal of a two year amortization is supported by the time elapsed between this case and Docket EL09-009, it was approximately 17 years between rate filings in Docket EL92-016 and Docket EL09-009. Staff's basis for the amortization period is a reasonable estimate of the number of years before the utility is expected to file its next rate case. Since NSP has filed very few rate cases in the past 20 years, it is difficult to look at history as a guide. Considering current economic conditions and forecasted capital investments, the settlement reflects a three year period as a reasonable period of time to expect that the rates established here will remain in effect. To protect both ratepayers and the Company in the event that three years is an inaccurate estimate, the settlement includes a tracking mechanism for the recovery of rate case costs so that the Company neither over recovers nor under recovers these costs.

Since the Parties are unable to resolve their differences on rate of return and the cost recovery of the Nobles wind farm, the Company will incur additional rate case costs presenting the case. The settlement reflects actual rate case expense through March 31, 2012, and additional costs incurred in this proceeding will be deferred until the next rate filing. The deferral accounting method and the resulting creation of a regulatory asset (the deferred balance) shall not preclude Commission review of these amounts for reasonableness for rate recovery in any determination of rates, including both rate filings by the Company and rate reviews initiated by the Commission.

Rate case expense from Docket EL09-009 was amortized over a five year period beginning January 18, 2010. Interim rates in this case were put into effect on January 3, 2012, leaving approximately three more years of cost recovery until the expenses are completely amortized. The settlement combines the unamortized rate case expense from Docket EL09-009 with the actual rate case expense from this rate proceeding, using the same amortization period and tracking mechanism as used for the current rate case costs. Including previous rate case costs in the tracking mechanism ensures that rate case costs from both cases are accounted for and fully recovered. The net effect of these changes reduces operating expenses by approximately $135,000.

Monticello Nuclear Plant Life Cycle Management/Extended Power Uprate (LCM/EPU) – The Company's rate filing included test year adjustments for 2011 capital expenditures supporting the Life Cycle Management/Extended Power Uprate (LCM/EPU) projects. Both projects have been approved by the MPUC; the NRC has approved the LCM project while the EPU is still under consideration. The settlement revises the Company's adjustment to reflect actual depreciation expense, property taxes, deferred income taxes and current income taxes through the end of 2011. The adjustment decreases operating expenses by approximately $190,000.

Prairie Island Nuclear Plant Life Extension Projects – The Company requested test year adjustments for 2011 capital projects supporting the 20-year Prairie Island life extension granted by the NRC. The settlement revises the Company's adjustment to reflect actual depreciation expense, property taxes, deferred income taxes and current income taxes through the end of 2011. The adjustment increases operating expenses by approximately $61,000.

King Mercury – In Docket EL10-012, the Commission approved cost recovery for the revenue requirements associated with the King generating facility mercury control systems through the ECR Rider. The Company requested to shift cost recovery from the ECR rider to base rates by annualizing the investments and costs associated with the control system placed in-service during December 2010. The settlement accepts this adjustment.

Merricourt – NSP has cancelled a proposed wind project in Merricourt, ND and its rate filing eliminates all related costs. Because the project costs were recorded in the Construction Work In-Progress account that is not a component of rate base in South Dakota, the eliminations are limited to deferred taxes. The settlement accepts this adjustment.

Steam Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect extensions of the estimated remaining lives and changes in salvage values of four steam production plants – Black Dog Units 3 and 4, Sherco Unit 3, and the refuse-fueled Red Wing and Wilmarth plants. The settlement accepts this adjustment.

Other Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect reductions in the estimated remaining lives and changes in salvage values of two additional steam production plants – Inver Hills and Riverside. The settlement accepts this adjustment.

Bonus Tax Depreciation – The Tax Relief Act of 2010, which was signed into law in December 2010, extended the "bonus" depreciation tax deduction allowance and allowed for a 100 percent bonus tax depreciation for certain projects placed into service from September 9, 2010, through December 31, 2011. The guidelines issued following enactment of the Tax Relief Act contained provisions that required different treatment for certain items during 2010 than what NSP had reflected on its books. Therefore, it was necessary for NSP to adjust its 2010 financial statements to reflect the new tax guidelines. The settlement accepts the adjustment.

Net Operating Loss - Please see the Net Operating Loss explanation in the Rate Base section. The settlement accepts this adjustment.

Union and Non-Union Wage Increases - The Company proposed an adjustment to test year Union labor costs to recognize increases taking place on January 1, 2011, based on contracts in place. The Company also proposed a non-Union test year adjustment for actual increases experienced on March 1, 2010, and 2011. The settlement accepts both adjustments.

Margin Sharing – The Company proposed an adjustment to remove the shareholders' portion of the non-asset based margin sharing arrangement that existed during the test year. The settlement accepts this adjustment.

Wholesale Billing – The Company proposed an adjustment to decrease operating expenses in order to assign additional costs to the wholesale jurisdiction, properly reflecting the costs of providing billing and account management services to wholesale customers. The settlement accepts this adjustment.

Xcel Energy Foundation Administration – The Company proposed to remove the costs associated with the administration of the Xcel Energy Foundation. The Xcel Energy Foundation is in charge of the administration of donations and charitable contributions. The settlement accepts this adjustment.

Employee Expense Reduction – NSP proposed an adjustment to eliminate certain employee expenses (sports events, tickets, sponsorships) which should have been recorded below the line but were not so recorded. The settlement accepts this adjustment.

Pension and Insurance - Following the close of the 2010 test year, NSP received a new actuarial determination of its annual pension expense for 2011. Also for 2011, NSP determined that its insurance expenses for retiree medical, long-term disability and workers compensation will decrease from their 2010 test year levels. The settlement accepts these known and measurable adjustments.

Weather Normalized Allocator – The Company proposed an adjustment to reflect the impact on expenses due to the difference between weather normalized demand and energy allocators and actual demand and energy allocators. The settlement revises this adjustment to reflect the change in other operating revenues due to the weather normalized allocators. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma investments, revenues and expenses that are allocated to the South Dakota retail jurisdiction based on energy and demand. Therefore, the precise value of the weather normalized allocator adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Rider Removal – The Company requested to remove all revenues collected through the TCR and ECR riders from the test year and move the revenue requirements to base rates. The adjustment also removes the revenue requirements associated with the Chisago transmission project from the test year. The Company proposed to collect the revenue requirements associated with the Chisago transmission project through the pending TCR filing, Docket EL12-035. The settlement accepts this adjustment.

Rounding – The Company proposed an adjustment to reflect potential rounding differences. NSP and Staff agree on the mechanics of the adjustment that is required. However, this adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Fox Lake Transmission Line – The Company sold the Lakefield Junction – Fox Lake transmission line (Fox Lake Transmission Line) to ITC Midwest on January 7, 2011. There was no gain or loss as a result of this transaction. This asset was improperly included in the test year as the transmission line is no longer owned by NSP. The settlement determination removes the revenue requirements associated with the Fox Lake Transmission Line. The adjustment decreases operating expenses base by approximately $34,000.

Fines – The Company paid fines related to one air quality incident at the King Generating Plant and three incidents of small fish losses as a result of zebra mussel treatments at the Prairie Island Nuclear Generating Unit during 2010. NSP must comply with all applicable laws and fines that result from imprudent management and these fines should not be borne by ratepayers. The settlement removes these expenses, decreasing operating expenses by $1,000.

Property Tax Update - During discovery, the Company proposed an adjustment to reflect the most recent actual property taxes paid. In place of the estimate included in the filing, the settlement reflects the actual 2010 property taxes paid on South Dakota property. The settlement also updates the test year to include the 2011 property taxes paid on Minnesota property owned as of the end of 2010. The most recent actual tax paid on property is more reflective of current operational expenses. The adjustment increases operating expenses by approximately $462,000.

Aviation Expense - The Company included the costs associated with two aircraft in the test year. In rate cases filed before the Minnesota Public Utilities Commission and North Dakota Public Service Commission, the Company only included the costs associated with one aircraft in the test year. In both filings, Company witnesses stated, "After carefully reviewing the costs and benefits associated with these aircraft, we are reducing the costs included in our test year to include only the costs of one of our corporate aircraft. We believe that this adjustment results in a conservative cost in relation to the benefits obtained." The settlement allocates the cost of one aircraft, supported by NSP's analysis of the costs and benefits associated with the aircraft. The adjustment decreases operating expenses by approximately $64,000.

Economic Development Labor – The settlement removes labor expenses associated with economic development activity that the Company did not include in its 2010 economic development plan. This adjustment reduces operating expenses by approximately $43,000.

Energy Efficiency – The settlement removes the conservation and demand side management costs that will be recovered through its Demand Side Management Cost Recovery rider from the test year. This adjustment reduces operating expenses by approximately $230,000.

Interest Synchronization - The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historic test year rate base as adjusted for known and measurable changes. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the weighted cost of long-term debt and pro forma rate base. Therefore, the precise value of the interest synchronization adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Schedule 26 Expenses and Revenue – The settlement reflects an adjustment to remove the Schedule 26 expenses and revenues from the test year so that going forward these expenses and revenues may be addressed in the pending TCR rider, Docket EL12-035. The effect of this adjustment reduces operating revenues by approximately $232,000 and reduces operating expenses by approximately $292,000.

Depreciation to Reflect 2012 Rates – In a late 2011 Minnesota rate settlement, NSP agreed to numerous adjustments to production, transmission, and distribution depreciation rates based upon an extensive review with the objective of "restoring intergenerational equity and providing rate mitigation benefits to consumers". Also, the Company anticipates that these rates will be supported by the periodic, five-year depreciation study it will file with the MPUC in July 2012. The rate settlement was approved by the presiding Minnesota Administrative Law Judge on February 22, and, with minor modifications, by the MPUC on March 29, 2012. The settlement reflects the application of these Company-supported rates to plant assigned or allocated to South Dakota during the test year. The net effect of these changes reduces operating expenses by approximately $2,273,000.

Executive Foreign Travel Expense - The settlement removes expenses for foreign travel by Xcel executives in the amount of approximately $1,000. Such costs are not necessary for safe, adequate and reliable service to South Dakota customers.

Gain on Sale of Emission Allowances - Consistent with the Commission's decision in Dockets EL09-018 and EL10-011, the settlement removes the gain on the sale of emission allowances from the test year so that the gain is not reflected in base rates. One hundred percent of the South Dakota jurisdictional share of the gain on the sale of emission allowances will be credited to the fuel clause rider beginning January 2, 2012. The allocation of emission allowances is directly related to the fuel used in electric generation, and the market price and the number of emission allowances sold can fluctuate so that we cannot accurately reflect the credit in base rates. This adjustment increases operating expenses by approximately $2,000.

Monticello "No Single Event" Capital Project - Please see the Monticello "No Single Event" Capital Project explanation in the Rate Base section. The settlement accepts this adjustment, increasing operating expenses by approximately $71,000.

Depreciation Annualization – During discovery, the Company proposed an adjustment to modify the depreciation expense included in the test year from three nuclear plant adjustments. The Monticello LCM/EPU, Prairie Island Life Extension, and Monticello "No Single Event" plant adjustments all included the actual 2011 depreciation expense in the test year. NSP proposed to reflect a full year of depreciation expense based on the actual investment cost. The settlement accepts this adjustment, increasing operating expenses by approximately $342,000.

Wind Production Tax Credits – NSP receives federal income tax credits based on the actual production from eligible wind projects. Currently, an allowance for these credits, based on the rate case test year wind production, is treated as a reduction in the Company's base rates. Recognizing that wind production is highly variable and unpredictable and that test year conditions are not likely to be repeated, the settlement passes Production Tax Credits (PTCs) on to ratepayers through the Company's Fuel Clause Rider (FCR), as the credits are earned based on actual wind production.

Removing the test year PTCs from the base rate revenue requirement increases the requirement by $551,000; however, under test year conditions, FCR charges would be reduced by that same amount. Under the terms of the settlement, FCR charges in the future will be reduced by the actual amount of the PTCs then earned by NSP.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. Tariffs will be filed with the Commission after a decision is rendered on rate of return and the Nobles wind farm. Staff concurred with the changes made by NSP for all rate schedules. The settlement positions reached between Staff and NSP regarding the distribution of the increase and miscellaneous service charge increases are discussed below.

Distribution of the Increase - NSP's rate filing included a class cost of service study ("CCOSS"). NSP's CCOSS showed that under current rates the large commercial and industrial customers have been subsidizing customers in the residential, commercial and street lighting classes. Based on this finding, NSP proposed larger rate increases, on a percentage basis, for the residential, commercial and street lighting classes and a smaller than system-wide average increase for the large commercial and industrial rate class.

The Commission Staff determined that NSP's CCOSS results are largely driven by the "minimum distribution system" approach upon which the Company relied on in order to allocate certain distribution costs (primarily conductors, transformers, and poles) among the rate classes. Under the minimum distribution system approach, the theoretical cost of a hypothetical distribution system composed solely of minimum sized components is allocated among the classes based on the relative number of customers within each rate class. The cost difference between the Company's actual system and the theoretical minimum sized distribution system is allocated using class non-coincident peak demands. The alternative to using the minimum distribution system approach is to allocate all of the costs of the conductors, transformers and poles actually installed on a peak demand basis. Had NSP used the alternate approach rather than the minimum distribution system approach, the CCOSS results would have been much different. That is, the subsidies shown in NSP's CCOSS would have been significantly reduced and/or eliminated completely.

The use of the minimum distribution system approach in CCOSS is controversial and not universally accepted by all state regulatory commissions. Staff does not endorse using the minimum distribution system approach in CCOSS. However, Staff cannot recall any previous rate case in which this issue has been addressed by the Commission. Therefore, for settlement purposes, Staff proposed and NSP agreed to distribute the increased revenue requirement on an equal percentage basis among all the Company's rate classes. A uniform percentage increase for all rate classes represents a reasonable middle ground between the results indicated in NSP's CCOSS using the minimum distribution system approach and a CCOSS using the alternative peak demand method.

Miscellaneous Service Charge Increases – The Company proposed increases to the following service charges: service reconnection charge, dedicated switching service, excess footage charges, and winter construction charges. The settlement revises the request to: 1. Derive the dedicated switching service revenue using the number of hours as opposed to the number of occurrences since the charge is based on an hourly amount; and 2. Reflect a service reconnection charge of $35 as opposed to the Company proposed $50 charge in an effort to avoid rate shock. The adjustment incorporating these two changes is reflected on Exhibit___(BAM-6), Schedule 1. The net effect of these changes reduces other operating revenues by approximately $12,000.

OTHER ISSUES

Nuclear Cost Recovery Rider – NSP withdrew its proposed Nuclear Cost Recovery rider during settlement negotiations.

Non-Asset Based Margins – NSP seeks to profit from energy trading activities, some of which are dependent on utility-owned or controlled power resources whose costs are reflected in utility rates (the so-called "Asset-based" transactions) while others are conducted without the direct support of these assets (Non-asset based transactions). The profit "margins" earned from these on-going activities are shared with ratepayers through the fuel adjustment clause at rates of 100% and 25%, respectively of the margins earned on Asset-based and Non-asset based transactions.

No change is proposed in the 100% sharing arrangement for Asset-based transactions. However, the Settlement increases ratepayers' share of the margins from Non-asset based transactions from 25% to 30% effective January 2, 2012.

Staff recommended the larger sharing rate for Non-asset based transactions after examining the results of two cost studies submitted by NSP in this case pursuant to the Settlement Stipulation in EL09-009. Staff concluded that, based on recent and anticipated experience, the 25% sharing rate would insure that ratepayers are not burdened with the incremental costs but that the 25% rate was insufficient to protect ratepayers from all costs (fully allocated costs) that are reasonably related to the Non-asset based transactions. Staff believed that the studies indicated that a 30% share would provide this protection and that the cost studies should be updated and submitted again in NSP's next rate filing.

Northern States Power Company
Docket EL11-019
South Dakota Electric Revenue Requirement
Adjusted Test Year Ended December 31, 2010 ($000's)

Exhibit___(BAM-1)
Schedule 1
Page 1 of 1

Line	Description	Staff Proposed South Dakota Electric Adjusted 2010 Test Year	NSP Originally Filed South Dakota Electric Adjusted 2010 Test Year	Difference
	(a)	(b)	(c)	(d)
1	Average Rate Base	$ 315,272	$ 323,392	$ (8,120)
2	Adjusted Test Year Operating Income	19,862	18,915	947
3	Earned Rate of Return	6.30%	5.85%	
4	Recommended Rate of Return	7 60%	8.78%	
5	Required Operating Income	23,961	28,394	(4,433)
6	Income Deficiency (Excess)	4,099	9,479	(5,380)
7	Gross Revenue Conversion Factor	1 53846	1.53846	
8	Revenue Deficiency (Excess)	6,306	14,583	(8,277)
9	Gross Receipts Tax (at 0.0015)	9	-	
10	**Total Revenue Deficiency (Excess)**	**6,315**	**14,583**	(8,268)
11	Adjusted Test Year Revenue	157,052	157,219	(167)
12	**Revenue Requirement**	**$ 163,367**	**$ 171,802**	$ (8,435)

SOURCES:

Column b, line 1: BAM-2, Schedule 1, page 1, column d, line 37
Column b, line 2 BAM-1, Schedule 2, page 1, column d, line 27
Column b, line 3 Line 2 divided by line 1
Column b, line 4 BLC-1, Schedule 1, line 3
Column b, line 5 Line 1 * line 4
Column b, line 6. Line 5 less line 2
Column b, line 7: Effective FIT rate / inverse + 1
Column b, line 8: Line 6 * line 7
Column b, line 9: Line 8 * 0 0015
Column b, line 10. Line 8 plus line 9
Column b, line 11. BAM-1, Schedule 2, page 1, column d, line 2
Column b, line 12. Line 11 plus line 10

Column c, line 1: Statement N, page 11 of 12, line 7, column SD Retail Electric
Column c, line 2. Statement N, page 11 of 12, line 6, column SD Retail Electric
Column c, line 3 Line 2 divided by line 1
Column c, line 4 Statement N, page 11 of 12, line 5, column Weighted Cost
Column c, line 5 Statement N, page 11 of 12, line 15, column SD Retail Electric
Column c, line 6 Statement N, page 11 of 12, line 17, column SD Retail Electric
Column c, line 8 Statement N, page 11 of 12, line 19, column SD Retail Electric
Column c, line 10 Line 8 plus line 9
Column c, line 11. Statement N, page 11 of 12, line 20, column SD Retail Electric
Column c, line 12. Line 10 plus line 11
Column d Column b less column c

Northern States Power Company
Docket EL11-019
SD Operating Income Statement With Known and Measurable Adjustments and Revenue Adjustment
Adjusted Test Year Ended December 31, 2010 ($000's)

Exhibit___(BAM-1)
Schedule 2
Page 1 of 1

Line No.	Description	South Dakota Per Books	Total Staff Adjustments	Adjusted Test Year	Revenue Adjustment	Adjusted Test Year with Revenue Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
1	OPERATING REVENUES					
2	Retail Revenue	$ 156,951	$ 101	$ 157,052	$ 6,315	$ 163,367
3	Other Electric Operating Revenue	39,152	(285)	38,867		38,867
4	**TOTAL OPERATING REVENUES**	196,103	(184)	195,919	6,315	202,234
5	OPERATING EXPENSES					
6	Operation and Maintenance					
7	Fuel & Purchased Energy	80,110	(10,502)	69,608		69,608
8	Power Production Expense	40,130	296	40,426		40,426
9	Transmission Expense	9,757	(303)	9,454		9,454
10	Distribution Expense	6,533	(156)	6,377		6,377
11	Customer Accounting Expense	3,996	-	3,996		3,996
12	Customer Service and Information Expense	492	(276)	216		216
13	Sales, Econ Dvlp & Other Expenses	3	50	53		53
14	Administration and General Expense	12,482	(884)	11,598		11,598
15	Other	-	-	-		-
16	Total Operation and Maintenance	153,503	(11,775)	141,728	-	141,728
17	Depreciation and Amortization	19,446	(1,710)	17,736		17,736
18	Taxes					
19	Property Taxes	5,560	768	6,328		6,328
20	Deferred Income Taxes and Investment Tax Credit	19,226	(8,430)	10,796		10,796
21	South Dakota Gross Receipts Tax	-	-	-	9	9
22	Payroll & Other Taxes	1,671	(1)	1,670		1,670
23	Federal Income Taxes	(13,970)	11,769	(2,201)	2,207	6
24	Other Taxes	-	-	-		-
25	Total Taxes	12,487	4,106	16,593	2,216	18,809
26	**TOTAL OPERATING EXPENSES**	185,436	(9,379)	176,057	2,216	178,273
27	**OPERATING INCOME**	$ 10,667	$ 9,195	$ 19,862	$ 4,099	$ 23,961
28	Rate Base	287,541		$ 315,272		$ 315,272
29	Earned Rate of Return	3 71%		6 30%		7 60%
30	Staff Proposed Rate of Return			7 60%		7 60%

SOURCES:

Line 4: Sum of lines 2 through 3
Line 16 Sum of lines 7 through 15
Line 25. Sum of lines 19 through 24
Line 26: Sum of lines 16, 17 and 25
Line 27: Line 4 less line 26
Line 28: BAM-2, Schedule 1, column d, line 37
Line 29: Line 27 / line 28
Line 30 BLC-1, Schedule 1, line 3
Column b: BAM-1, Schedule 3, column b

Column c BAM-1, Schedule 3, column ay
Column d Column b plus column c

Column e, line 2: BAM-1, Schedule 1, column b, line 10
Column e, line 21: BAM-1, Schedule 1, column b, line 9
Column e, line 23 BAM-1, Schedule 1, column b, line 8 less BAM-1, Schedule 1, column b, line 6
Column f Column d plus column e

Northern States Power Company
Docket EL11-019
South Dakota Electric Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2010 ($000's)

Exhibit___(BAM-1)
Schedule 3
Page 1 of 7

Line No	Description (a)	South Dakota Per Books (b)	Weather Normalization (c)	Fuel Lag (d)	Fuel Recovery Timing (e)	Incentive Compensation (f)	Vegetation Management (g)	Storm Damage (h)	Claims & Injury Compensation (i)	Fuel Expense Write-Off (j)	Advertising (k)
1	OPERATING REVENUES										
2	Retail Revenue	$ 156,951	$ (1,447)	$ (407)	$ 2,635						
3	Other Electric Operating Revenue	39,152									
4	TOTAL OPERATING REVENUES	196,103	(1,447)	(407)	2,635	-	-	-	-	-	-
5	OPERATING EXPENSES.										
6	Operation and Maintenance.										
7	Fuel & Purchased Energy	80,110	(488)	(407)						(9,607)	
8	Power Production Expense	40,130									
9	Transmission Expense	9,757					(10)				
10	Distribution Expense	6,533					(35)	(121)			
11	Customer Accounting Expense	3,996									
12	Customer Service and Information Expense	492									(74)
13	Sales, Econ Dvlp & Other Expenses	3									
14	Administration and General Expense	12,482				(1,382)			(6)		(153)
15	Other										
16	Total Operation and Maintenance	153,503	(488)	(407)	-	(1,382)	(45)	(121)	(6)	(9,607)	(227)
17	Depreciation and Amortization	19,446									
18	Taxes										
19	Property Taxes	5,560									
20	Deferred Income Taxes and Investment Tax Credit	19,226									
21	South Dakota Gross Receipts Tax	-									
22	Payroll & Other Taxes	1,671									
23	Federal Income Taxes	(13,970)	(336)	-	922	484	16	42	2	3,362	79
24	Other Taxes										
25	Total Taxes	12,487	(336)	-	922	484	16	42	2	3,362	79
26	TOTAL OPERATING EXPENSES	185,436	(824)	(407)	922	(898)	(29)	(79)	(4)	(6,245)	(148)
27	OPERATING INCOME	$ 10,667	(623)	-	1,713	898	29	79	4	6,245	148
	Source	Exhibit_(TEK-1) Schedule 6b, pg 1	BAM-3, Sch 1	Exhibit_(TEK-1) Sch. 6b, pg. 1 Column (3)	Exhibit_(TEK-1) Sch. 6b, pg. 1 Column (4)	DAJ-1, Sch 4	JPT-1, Sch 4	JPT-1, Sch 2	JPT-1, Sch 3	Exhibit_(TEK-1) Sch. 6b, pg 1 Column (9)	MAT-1, Sch 3
	Staff Witness Testimony		Mehlhaff	Mehlhaff	Mehlhaff	Jacobson	Thurber	Thurber	Thurber	Mehlhaff	Tysdal
	Staff position on NSP's Adjustment		Adjusted	Accepted	Accepted	Adjusted	Adjusted	Adjusted	Adjusted	Accepted	Adjusted

Northern States Power Company
Docket EL11-019
South Dakota Electric Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2010 ($000's)

Line No.	Description (a)	Economic Development (l)	Interest on Customer Deposits (m)	Association Dues (n)	Donations (o)	SFAS 106 Pay Go (p)	Rate Case Expense (q)	Noble Wind (r)	Monti LCM/EPU (s)	PI Life Extension (t)	King Mercury (u)
1	OPERATING REVENUES										
2	Retail Revenue										
3	Other Electric Operating Revenue										
4	TOTAL OPERATING REVENUES	-	-	-	-	-	-	-	-	-	-
5	OPERATING EXPENSES.										
6	Operation and Maintenance:										
7	Fuel & Purchased Energy										
8	Power Production Expense										
9	Transmission Expense										
10	Distribution Expense										
11	Customer Accounting Expense										
12	Customer Service and Information Expense										
13	Sales, Econ Dvlp & Other Expenses	50									
14	Administration and General Expense		1	(8)		215					
15	Other										
16	Total Operation and Maintenance	50	1	(8)	-	215	-	-	-	-	-
17	Depreciation and Amortization				-		59	704	322	188	6
18	Taxes										
19	Property Taxes							190	70	51	2
20	Deferred Income Taxes and Investment Tax Credit					46		(3,321)	2,475	326	(37)
21	South Dakota Gross Receipts Tax										
22	Payroll & Other Taxes										
23	Federal Income Taxes	(18)	-	3		(115)	(21)	2,432	(2,233)	(379)	28
24	Other Taxes										
25	Total Taxes	(18)	-	3	-	(69)	(21)	(699)	312	(2)	(7)
26	TOTAL OPERATING EXPENSES	32	1	(5)	-	146	38	5	634	186	(1)
27	OPERATING INCOME	(32)	(1)	5	-	(146)	(38)	(5)	(634)	(186)	1
	Source	Exhibit_(TEK-1) Sch 6b, pg. 1 Column (11)	Exhibit_(TEK-1) Sch. 6b, pg 1 Column (12)	MAT-1, Sch 2	Exhibit_(TEK-1) Sch. 6b, pg. 1, Column (14)	Exhibit_(TEK-1) Sch. 6b, pg. 1, Column (15)	MAT-1, Sch 1	Email from Paulson to Rounds on 3/9/12	DR 2-9 Revised	DR 6-5 Atch E	DR 5-1
	Staff Witness Testimony	Tysdal	Jacobson	Tysdal	Tysdal	Peterson	Tysdal	Maini	Towers	Towers	Thurber
	Staff position on NSP's Adjustment	Accepted	Accepted	Adjusted	Accepted	Accepted	Adjusted	Adjusted	Adjusted	Adjusted	Accepted

Adjusted Test Year Ended December 31, 2010 ($000's)

Line No	Description	Merricourt	Steam Remaining Life	Other Prod Remaining Life	Bonus Tax Depreciation	Net Operating Loss	Union Wage Adjustment	Non-Union Wage Adjustment	Margin Sharing	Wholesale Billing	Foundation Administration Costs
	(a)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)
1	OPERATING REVENUES:										
2	Retail Revenue										
3	Other Electric Operating Revenue								(135)		
4	**TOTAL OPERATING REVENUES**	-	-	-	-	-	-	-	(135)	-	-
5	OPERATING EXPENSES										
6	Operation and Maintenance										
7	Fuel & Purchased Energy										
8	Power Production Expense										
9	Transmission Expense										
10	Distribution Expense										
11	Customer Accounting Expense										
12	Customer Service and Information Expense										
13	Sales, Econ Dvlp & Other Expenses										
14	Administration and General Expense						161	277		(10)	(21)
15	Other										
16	Total Operation and Maintenance	-	-	-	-	-	161	277	-	(10)	(21)
17	Depreciation and Amortization		(525)	108							
18	Taxes.										
19	Property Taxes										
20	Deferred Income Taxes and Investment Tax Credit	10	200	(42)	(3,705)	(4,464)					
21	South Dakota Gross Receipts Tax										
22	Payroll & Other Taxes										(1)
23	Federal Income Taxes	(9)	-	-	3,173	3,858	(56)	(97)	(47)	4	8
24	Other Taxes										
25	Total Taxes	1	200	(42)	(532)	(606)	(56)	(97)	(47)	4	7
26	**TOTAL OPERATING EXPENSES**	1	(325)	66	(532)	(606)	105	180	(47)	(6)	(14)
27	**OPERATING INCOME**	(1)	325	(66)	532	606	(105)	(180)	(88)	6	14
	Source	Exhibit_(TEK-1) Sch 6b, pg 2, Column (21)	Exhibit_(TEK-1) Sch 6b, pg 2, Column (22)	Exhibit_(TEK-1) Sch. 6b, pg 2, Column (23)	Exhibit_(TEK-1) Sch. 6b, pg 2 Column (24)	Email from Kramer to Mehlhaff on 4/18/12	Exhibit_(TEK-1) Sch. 6b, pg 2 Column (26)	Exhibit_(TEK-1) Sch. 6b, pg 2 Column (27)	Exhibit_(TEK-1) Sch. 6b, pg. 2 Column (28)	Exhibit_(TEK-1) Sch. 6b, pg 2 Column (29)	Exhibit_(TEK-1) Sch. 6b, pg 2 Column (30)
	Staff Witness Testimony	Towers	Towers	Towers	Peterson	Peterson	Jacobson	Jacobson	Towers	Mehlhaff	Tysdal
	Staff position on NSP's Adjustment	Accepted	Accepted	Accepted	Accepted	Accepted	Accepted	Accepted	Accepted	Accepted	Accepted

Line No	Description	Employee Expense Reduction	Pension and Insurance	Weather Normalized Allocator	Rider Removal	Rounding	Fox Lake Transmission Assets	Fines	Property Tax Update	Aviation Expense
	(a)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)
1	OPERATING REVENUES.									
2	Retail Revenue				$ (680)					
3	Other Electric Operating Revenue			82						
4	**TOTAL OPERATING REVENUES**	-	-	82	(680)	-	-	-	-	-
5	OPERATING EXPENSES									
6	Operation and Maintenance.									
7	Fuel & Purchased Energy									
8	Power Production Expense			296						
9	Transmission Expense			(1)						
10	Distribution Expense									
11	Customer Accounting Expense									
12	Customer Service and Information Expense									
13	Sales, Econ Dvlp & Other Expenses									
14	Administration and General Expense	(25)	204					(1)		(64)
15	Other									
16	Total Operation and Maintenance	(25)	204	295	-	-	-	(1)	-	(64)
17	Depreciation and Amortization				(636)		(23)			
18	Taxes.									
19	Property Taxes				(2)		(8)		462	
20	Deferred Income Taxes and Investment Tax Credit				(123)		(13)			
21	South Dakota Gross Receipts Tax									
22	Payroll & Other Taxes									
23	Federal Income Taxes	9	(71)	(75)	79		22		(162)	22
24	Other Taxes									
25	Total Taxes	9	(71)	(75)	(46)	-	1	-	300	22
26	**TOTAL OPERATING EXPENSES**	(16)	133	220	(682)	-	(22)	(1)	300	(42)
27	**OPERATING INCOME**	16	(133)	(138)	2	-	22	1	(300)	42
	Source	Exhibit_(TEK-1) Sch 6b, pg. 2 Column (31)	Exhibit_(TEK-1), Sch. 6b, pg 3 Column (32)	Email from Kramer to Thurber on 4/16/12	Exhibit_(TEK-1), Sch. 6b, pg. 3 Column (34)	Email from Kramer to Mehlhaff on 4/18/12	DR 1-24	DR 1-4	DR 6-8 & Email from Paulson to Thurber on 4/4/12	DR 7-2
	Staff Witness Testimony	Jacobson	Peterson	Mehlhaff	Thurber	Mehlhaff	Thurber	Thurber	Thurber	Thurber
	Staff position on NSP's Adjustment	Accepted	Accepted	Adjusted	Accepted	Accepted	Staff Proposed	Staff Proposed	Company Proposed	Staff Proposed

Northern States Power Company
Docket EL11-019
South Dakota Electric Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2010 ($000's)

Exhibit___(BAM-1)
Schedule 3
Page 5 of 7

Line No.	Description	Economic Development Labor	Energy Efficiency	Interest Sync	Schedule 26 Expenses and Revenues	Depreciation to Reflect 2012 Rates	Executive Foreign Travel Expenses	Gain on Sale of Emission Allowances	Monticello No Single Event Capital Project
	(a)	(ao)	(ap)	(aq)	(ar)	(as)	(at)	(au)	(av)
1	OPERATING REVENUES:								
2	Retail Revenue								
3	Other Electric Operating Revenue				(232)				
4	**TOTAL OPERATING REVENUES**	-	-	-	(232)	-	-	-	-
5	OPERATING EXPENSES								
6	Operation and Maintenance:								
7	Fuel & Purchased Energy								
8	Power Production Expense								
9	Transmission Expense				(292)				
10	Distribution Expense								
11	Customer Accounting Expense								
12	Customer Service and Information Expense		(202)						
13	Sales, Econ Dvlp & Other Expenses								
14	Administration and General Expense	(43)	(28)				(1)		
15	Other								
16	Total Operation and Maintenance	(43)	(230)	-	(292)	-	(1)	-	-
17	Depreciation and Amortization					(2,273)		2	16
18	Taxes								
19	Property Taxes								3
20	Deferred Income Taxes and Investment Tax Credit								218
21	South Dakota Gross Receipts Tax								
22	Payroll & Other Taxes								
23	Federal Income Taxes	15	81	(116)	21	796		(1)	(191)
24	Other Taxes								
25	Total Taxes	15	81	(116)	21	796	-	(1)	30
26	**TOTAL OPERATING EXPENSES**	(28)	(149)	(116)	(271)	(1,477)	(1)	1	46
27	**OPERATING INCOME**	28	149	116	39	1,477	1	(1)	(46)
	Source	DR 6-7	DR 9-7	JPT-1 Sch 5	Email from Kramer to Mehlhaff on 2/29/12	DR 2-8	DR 5-24	DR 7-3	DR 5-6 Supplement
	Staff Witness Testimony	Tysdal	Tysdal	Thurber	Mehlhaff	Peterson	Towers	Thurber	Thurber
	Staff position on NSP's Adjustment	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed	Company Proposed

Northern States Power Company
Docket EL11-019
South Dakota Electric Operating Income Statement With Known and Measurable Adjustments
Adjusted Test Year Ended December 31, 2010 ($000's)

Line No.	Description (a)	Depreciation Annualization (aw)	Production Tax Credits (ax)	Subtotal Staff Adjustments (ay)	Adjusted Test Year (az)
1	OPERATING REVENUES				
2	Retail Revenue			$ 101	$ 157,052
3	Other Electric Operating Revenue			(285)	38,867
4	**TOTAL OPERATING REVENUES**	-	-	(184)	195,919
5	OPERATING EXPENSES:				
6	Operation and Maintenance:				
7	Fuel & Purchased Energy			(10,502)	69,608
8	Power Production Expense			296	40,426
9	Transmission Expense			(303)	9,454
10	Distribution Expense			(156)	6,377
11	Customer Accounting Expense			-	3,996
12	Customer Service and Information Expense			(276)	216
13	Sales, Econ Dvlp & Other Expenses			50	53
14	Administration and General Expense			(884)	11,598
15	Other			-	-
16	Total Operation and Maintenance	-	-	(11,775)	141,728
17	Depreciation and Amortization	342		(1,710)	17,736
18	Taxes.				
19	Property Taxes			768	6,328
20	Deferred Income Taxes and Investment Tax Credit			(8,430)	10,796
21	South Dakota Gross Receipts Tax			-	-
22	Payroll & Other Taxes			(1)	1,670
23	Federal Income Taxes	(120)	358	11,769	(2,201)
24	Other Taxes			-	-
25	Total Taxes	(120)	358	4,106	16,593
26	**TOTAL OPERATING EXPENSES**	222	358	(9,379)	176,057
27	**OPERATING INCOME**	(222)	(358)	$ 9,195	$ 19,862
	Source	Email from Kramer to Thurber on 3/28/12	Email from Kramer to Thurber on 3/28/12		
	Staff Witness Testimony	Thurber	Towers		
	Staff position on NSP's Adjustment	Company Proposed	Staff Proposed		

Exhibit SPS-Staff 7-20 (SUPP1)
Page 41 of 78

Northern States Power Company
Docket EL11-019
South Dakota Electric Operating Income Statement With Known and Meaurable Adjustments
Adjusted Test Year Ended December 31, 2010 ($000's)

SOURCES:

Line 4:	Sum of lines 2 through 3
Line 16:	Sum of lines 7 through 15
Line 25:	Sum of lines 19 through 24
Line 26:	Sum of lines 16, 17, and 25
Line 27:	Line 4 less line 26

Northern States Power Company
Docket EL11-019
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2010 ($000's)

Exhibit___(BAM-2)
Schedule 1
Page 1 of 1

Line No.	Description	South Dakota Test Year Average Per Books	Total Pro Forma Adjustments	South Dakota Pro Forma Rate Base
	(a)	(b)	(c)	(d)
1	Electric Plant as Booked			
2	Production	$ 394,510	$ 26,387	$ 420,897
3	Transmission	97,917	(1,584)	96,333
4	Distribution	180,529	-	180,529
5	General	17,445	-	17,445
6	Common	23,970	-	23,970
7	Total Plant in Service	714,371	24,803	739,174
8	Reserve for Depreciation			
9	Production	236,566	129	236,695
10	Transmission	32,575	(253)	32,322
11	Distribution	72,024	(850)	71,174
12	General	6,866	-	6,866
13	Common	14,938	-	14,938
14	Total Reserve for Depreciation	362,969	(974)	361,995
15	TOTAL NET ELECTRIC PLANT IN SERVICE	351,402	25,777	377,179
16	Additions to Rate Base:			
17	Cash Working Capital	(2,794)	(107)	(2,901)
18	Tax Collections Available	-	(361)	(361)
19	Material and Supplies	6,260	743	7,003
20	Fuel Inventory	4,816	92	4,908
21	Prepayments	1,122	(69)	1,053
22	Nuclear Outage - Change of Accounting	3,090	-	3,090
23	SD Private Fuel Amortization	933	(428)	505
24	Rate Case Expense Amortization	244	(73)	171
25	SD AFUDC Amortization	4,715	-	4,715
26	Other Working Capital	266	-	266
27	Other	-	-	-
28	TOTAL ADDITIONS TO RATE BASE	18,652	(203)	18,449
29	Deductions to Rate Base:			
30	Accumulated Deferred Income Taxes	75,503	1,639	77,142
31	Non-Plant Assets and Liabilities	6,495	(3,892)	2,603
32	Interest on Customer Deposits	156	-	156
33	Customer Advances	157	188	345
34	SD SO2 Emission Allowance Sales Amortization	202	(92)	110
35	Other	-	-	-
36	TOTAL DEDUCTIONS TO RATE BASE	82,513	(2,157)	80,356
37	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 287,541**	**$ 27,731**	**$ 315,272**

Sources:

Line 7: Sum of lines 2 through 6
Line 14: Sum of lines 9 through 13
Line 15: Line 7 less line 14
Line 28: Sum of lines 17 through 27
Line 36: Sum of lines 30 through 35

Line 37: Line 15 plus line 28 less line 36
Column b: BAM-2, Schedule 2, page 1, column b
Column c: BAM-2, Schedule 2, page 2, column w
Column d: column b plus column c

Northern States Power Company
Docket EL11-019
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2010 ($000's)

Line No.	Description	South Dakota Test Year Average Per Books	SFAS 106 Pay Go	Noble Wind	Monti LCM/EPU	PI Life Extension	King Mercury	Merricourt	Steam Remaining Life	Other Prod Remaining Life
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Electric Plant as Booked									
2	Production	$394,510		15,435	6,156	4,280	142			
3	Transmission	97,917								
4	Distribution	180,529								
5	General	17,445								
6	Common	23,970								
7	Total Plant in Service	714,371	-	15,435	6,156	4,280	142	-	-	-
8	Reserve for Depreciation									
9	Production	236,566		395	(173)	90	3		(263)	54
10	Transmission	32,575								
11	Distribution	72,024								
12	General	6,866								
13	Common	14,938								
14	Total Reserve for Depreciation	362,969	-	395	(173)	90	3	-	(263)	54
15	TOTAL NET ELECTRIC PLANT IN SERVICE	351,402	-	15,040	6,329	4,190	139	-	263	(54)
16	Additions to Rate Base.									
17	Cash Working Capital	(2,794)								
18	Tax Collections Available	-								
19	Material and Supplies	6,260								
20	Fuel Inventory	4,816								
21	Prepayments	1,122								
22	Nuclear Outage Amortization	3,090								
23	SD Private Fuel Amortization	933								
24	Rate Case Expense Amortization	244								
25	SD AFUDC Amortization	4,715								
26	Other Working Capital	266								
27	Other	-								
28	TOTAL ADDITIONS TO RATE BASE	18,652	-	-	-	-	-	-	-	-
29	Deductions to Rate Base									
30	Accumulated Deferred Income Taxes	75,503	1,577	2,326	1,181	561	19	14	100	(21)
31	Non-Plant Assets and Liabilities	6,495	(3,892)							
32	Interest on Customer Deposits	156								
33	Customer Advances	157								
34	SD SO2 Emission Allowance Sales Amortization	202								
35	Other									
36	TOTAL DEDUCTIONS TO RATE BASE	82,513	(2,315)	2,326	1,181	561	19	14	100	(21)
37	**TOTAL SOUTH DAKOTA RATE BASE**	**$ 287,541**	**2,315**	**12,714**	**5,148**	**3,629**	**120**	**(14)**	**163**	**(33)**
	Source	Exhibit_(TEK-1) Schedule 6a, pg 1	Exhibit_(TEK-1) Sch. 6a, pg. 1, Column (2)	Email from Paulson to Rounds on 3/9/12	DR 2-9 Revised	DR 6-5 Atch E	DR 5-1	Exhibit_(TEK-1) Sch 6a, pg. 1, Column (7)	Exhibit_(TEK-1) Sch 6a, pg. 1, Column (8)	Exhibit_(TEK-1) Sch 6a, pg. 1, Column (9)
	Staff Witness Testimony		Peterson	Maini	Towers	Towers	Thurber	Towers	Towers	Towers
	Staff position on NSP's Adjustment		Accepted	Adjusted	Adjusted	Adjusted	Accepted	Accepted	Accepted	Accepted

Northern States Power Company
Docket EL11-019
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2010 ($000's)

Line No	Description (a)	Bonus Tax Depreciation (k)	Net Operating Loss (l)	Chisago Transmission Line (m)	Income Statement (CWC) (n)	Fox Lake Transmission Assets (o)	EL09-009 Amortizations (p)	Depreciation to Reflect 2012 Rates (q)	Rate Case Expense (r)	Updates (s)
1	Electric Plant as Booked									
2	Production									
3	Transmission			(658)		(922)				
4	Distribution									
5	General									
6	Common									
7	Total Plant in Service	-	-	(658)	-	(922)	-	-	-	-
8	Reserve for Depreciation									
9	Production							(148)		
10	Transmission			(13)		(101)		(139)		
11	Distribution							(850)		
12	General									
13	Common									
14	Total Reserve for Depreciation	-	-	(13)	-	(101)	-	(1,137)	-	-
15	TOTAL NET ELECTRIC PLANT IN SERVICE	-	-	(645)	-	(821)	-	1,137	-	-
16	Additions to Rate Base:									
17	Cash Working Capital				(107)					
18	Tax Collections Available				(361)					
19	Material and Supplies									743
20	Fuel Inventory									92
21	Prepayments									(69)
22	Nuclear Outage Amortization									
23	SD Private Fuel Amortization						(428)			
24	Rate Case Expense Amortization								(73)	
25	SD AFUDC Amortization									
26	Other Working Capital									
27	Other									
28	TOTAL ADDITIONS TO RATE BASE	-	-	-	(468)	-	(428)	-	(73)	766
29	Deductions to Rate Base:									
30	Accumulated Deferred Income Taxes	(1,853)	(2,232)	(35)		(106)				
31	Non-Plant Assets and Liabilities									
32	Interest on Customer Deposits									
33	Customer Advances									188
34	SD SO2 Emission Allowance Sales Amortization						(92)			
35	Other									
36	TOTAL DEDUCTIONS TO RATE BASE	(1,853)	(2,232)	(35)	-	(106)	(92)	-	-	188
37	**TOTAL SOUTH DAKOTA RATE BASE**	1,853	2,232	(610)	(468)	(715)	(336)	1,137	(73)	578
	Source	Exhibit_(TEK-1) Sch 6a, pg. 1 Column (10)	Email from Kramer to Mehlhaff on 4/18/12	Exhibit_(TEK-1) Sch. 6a, pg. 1 Column (12)	DAJ-1, Sch 1 & 2	DR 1-24	JPT-1, Sch 1	DR 2-8	MAT-1, Sch 1	DAJ-1, Sch 3
	Staff Witness Testimony	Peterson	Peterson	Thurber	Jacobson	Thurber	Thurber	Towers	Tysdal	Jacobson
	Staff position on NSP's Adjustment	Accepted	Accepted	Accepted	Adjusted	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed	Staff Proposed

Northern States Power Company
Docket EL11-019
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2010 ($000's)

Line No.	Description	Monticello No Single Event Capital Project	Weather Normalized Allocator	Depreciation Annualization	Total Staff Adjustments	Total Staff South Dakota Rate Base
	(a)	(t)	(u)	(v)	(w)	(x)
1	Electric Plant as Booked					
2	Production	302	72		$ 26,387	$ 420,897
3	Transmission		(4)		(1,584)	96,333
4	Distribution				-	180,529
5	General				-	17,445
6	Common				-	23,970
7	Total Plant in Service	302	68	-	24,803	739,174
8	Reserve for Depreciation					
9	Production	-		171	129	236,695
10	Transmission				(253)	32,322
11	Distribution				(850)	71,174
12	General				-	6,866
13	Common				-	14,938
14	Total Reserve for Depreciation	-	-	171	(974)	361,995
15	TOTAL NET ELECTRIC PLANT IN SERVICE	302	68	(171)	25,777	377,179
16	Additions to Rate Base					
17	Cash Working Capital				(107)	(2,901)
18	Tax Collections Available				(361)	(361)
19	Material and Supplies				743	7,003
20	Fuel Inventory				92	4,908
21	Prepayments				(69)	1,053
22	Nuclear Outage Amortization				-	3,090
23	SD Private Fuel Amortization				(428)	505
24	Rate Case Expense Amortization				(73)	171
25	SD AFUDC Amortization				-	4,715
26	Other Working Capital				-	266
27	Other				-	-
28	TOTAL ADDITIONS TO RATE BASE	-	-	-	(203)	18,449
29	Deductions to Rate Base.					
30	Accumulated Deferred Income Taxes	108			1,639	77,142
31	Non-Plant Assets and Liabilities				(3,892)	2,603
32	Interest on Customer Deposits				-	156
33	Customer Advances				188	345
34	SD SO2 Emission Allowance Sales Amortization				(92)	110
35	Other				-	-
36	TOTAL DEDUCTIONS TO RATE BASE	108	-	-	(2,157)	80,356
37	**TOTAL SOUTH DAKOTA RATE BASE**	**194**	**68**	**(171)**	**27,731**	**$ 315,272**
	Source	DR 5-6 Supplement	Email from Kramer to Thurber on 4/16/12	Email from Kramer to Thurber on 3/28/12		
	Staff Witness Testimony	Thurber	Mehlhaff	Thurber		
	Staff position on NSP's Adjustment	Company Proposed	Adjusted	Company Proposed		

Northern States Power Company
Docket EL11-019
South Dakota Average Rate Base with Known and Measurable Adjustments
Adjusted Test Year Ending December 31, 2010 ($000's)

Exhibit___(BAM-2)
Schedule 2
Page 4 of 4

Sources

Line 7: Sum of lines 2 through 6
Line 14: Sum of lines 9 through 13
Line 15: Line 7 less line 14
Line 28: Sum of lines 17 through 27
Line 36: Sum of lines 30 through 35
Line 37: Line 15 plus 28 less line 36

Column b, line 2-6, 9-13, 17-27, 30-35: Exhibit_(TEK-1), Schedule 6a, pg 1, Column (1)

Northern States Power Company
Docket EL11-019
Weather Normalization Adjustment
Adjusted Test Year Ending December 31, 2010 ($000's)

Exhibit___(BAM-3)
Schedule 1
Page 1 of 1

State of South Dakota - Calendar Year 2010

Total Revenue - Present

	ACTUAL			WEATHER NORMALIZED			WEATHER NORMALIZED ADJ		
	SUM	WIN	ANN	SUM	WIN	ANN	SUM	WIN	ANN
AllRes	27,255	39,720	66,975	26,517	39,455	65,972	-738	-264	-1,003
RES	25,945	36,894	62,839	25,230	36,640	61,870	-715	-254	-969
RSH	1,310	2,826	4,136	1,287	2,816	4,102	-24	-10	-34
SCI	28,036	42,322	70,358	27,721	42,202	69,923	-315	-120	-435
LCI	8,165	11,810	19,974	8,158	11,808	19,965	-7	-2	-9
LTG	354	835	1,189	354	835	1,189	0	0	0
OPA	1	2	3	1	2	3	0	0	0
Retail	63,811	94,688	**158,499**	62,750	94,301	**157,052**	-1,061	-387	**-1,447**

Base Revenue - Present

	SUM	WIN	ANN	SUM	WIN	ANN	SUM	WIN	ANN
AllRes	20,114	28,668	48,781	19,599	28,490	48,088	-515	-178	-693
RES	19,146	26,734	45,879	18,647	26,562	45,209	-499	-171	-670
RSH	968	1,934	2,902	952	1,927	2,879	-16	-7	-23
SCI	18,650	26,849	45,500	18,455	26,778	45,233	-195	-71	-266
LCI	4,850	6,650	11,500	4,850	6,650	11,500	0	0	0
LTG	294	661	955	294	661	955	0	0	0
OPA	1	2	3	1	2	3	0	0	0
Retail	43,908	62,829	**106,738**	43,198	62,580	**105,778**	-710	-249	**-959**

Fuel Revenue - Present

	SUM	WIN	ANN	SUM	WIN	ANN	SUM	WIN	ANN
AllRes	7,141	11,052	18,194	6,918	10,966	17,884	-223	-87	-310
RES	6,799	10,160	16,959	6,583	10,077	16,661	-216	-83	-299
RSH	342	892	1,234	335	888	1,223	-7	-4	-11
SCI	9,386	15,473	24,859	9,266	15,424	24,690	-120	-49	-169
LCI	3,315	5,160	8,475	3,308	5,158	8,465	-7	-2	-9
LTG	60	174	234	60	174	234	0	0	0
OPA	0	0	0	0	0	0	0	0	0
Retail	19,903	31,859	**51,761**	19,552	31,721	**51,273**	-351	-138	**-488**

MWH Sales

	SUM	WIN	ANN	SUM	WIN	ANN	SUM	WIN	ANN
AllRes	269,525	427,296	696,821	261,664	424,120	685,784	-7,861	-3,176	-11,037
RES	256,610	392,804	649,414	248,997	389,763	638,760	-7,613	-3,041	-10,654
RSH	12,915	34,491	47,406	12,667	34,357	47,024	-248	-135	-382
SCI	356,033	601,298	957,331	352,234	599,637	951,871	-3,799	-1,661	-5,460
LCI	129,099	205,916	335,015	129,099	205,916	335,015	0	0	0
LTG	2,819	8,304	11,123	2,819	8,304	11,122	0	0	0
OPA	0	0	0				0	0	0
Retail	757,476	1,242,813	2,000,289	745,816	1,237,976	1,983,792	-11,660	-4,837	-16,497

Bills

	SUM	WIN	ANN	SUM	WIN	ANN
AllRes	289,651	578,669	868,320	289,651	578,669	868,320
RES	275,049	549,541	824,590	275,049	549,541	824,590
RSH	14,602	29,128	43,730	14,602	29,128	43,730
SCI	41,606	83,166	124,772	41,606	83,166	124,772
LCI	68	139	207	68	139	207
LTG	654	1,310	1,964	654	1,310	1,964
OPA	0	0	0	0	0	0
Retail	331,979	663,284	995,263	331,979	663,284	995,263

Notes: Excludes Non-Fuel Riders (TCR & ECR), and Margin Sharing

Source: DR 8-41 Attachment B