414 Nicollet Mall
Minneapolis, Minnesota 55401

March 26, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Northern States Power Company, a Minnesota corporation,
Docket No. ER12-____-000
Northern States Power Company, a Wisconsin corporation,
Docket No. ER12-____-000
Interchange Agreement – Annual Update and E-Tariff Submission
Revised Tariff Pages Effective January 1, 2012

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act,[1] Section 35.13 of the regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] and Order No. 714,[3] Northern States Power Company, a Minnesota corporation ("NSPM") and Northern States Power Company, a Wisconsin corporation ("NSPW) (jointly the "NSP Companies"), submit an electronic tariff filing of revisions to the "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (hereafter "Interchange Agreement" or "Agreement").

The NSP Companies are submitting the proposed revisions under two docket numbers because NSPM is the designated filing party for the Interchange Agreement for purposes of the e-Tariff rules, and NSPW is submitting a concurrence record, as required by Order No. 714.

The following exhibits are being restated or revised:

Exhibits VII, VIII, and IX
Exhibit V
Exhibit V, Schedule 1.1 (new text)
Exhibit V, Schedule 4.1 (new text)

[1] 16 U.S.C. § 824d (2006).
[2] 18 C.F.R. § 35.13 (2009).
[3] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (Sept. 19, 2008) ("E-Tariff Final Rule").

Pursuant to Section 14.2 of the Interchange Agreement, Exhibits VII, VIII, and IX are not subject to automatic adjustment and may only be changed by a Section 205 filing. In addition to required updates to Exhibits VII, VIII, and IX, we also propose modifications to Exhibit V and associated Schedules 1.1 and 4.1 to correctly account for certain NSP Companies transmission investments granted Order No. 679[4] incentives and are receiving a current return on construction expenditures. The NSP Companies propose the revised tariff sheets be effective January 1, 2012, and request any waiver necessary for the tariff sheets to be effective on the date requested.

A. Background

NSPM is an investor-owned Minnesota corporation engaged in, inter alia, the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Minnesota, North Dakota, and South Dakota. NSPW is an investor-owned Wisconsin corporation engaged in, inter alia, the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Wisconsin and Michigan. The NSP Companies are both wholly-owned utility operating company subsidiaries of Xcel Energy Inc. Xcel Energy Services Inc. ("XES") is the service company for the Xcel Energy holding company system, and represents the Xcel Energy Operating Companies in proceedings before the Commission.[5]

The Interchange Agreement is a formula rate which provides for charges between NSPM and NSPW for certain electric production and transmission costs related to the NSP Companies' integrated electric system (the "NSP System"). Pursuant to the terms of the Agreement, the NSP Companies annually restate or update certain exhibits to the Interchange Agreement.[6] In the 2001 annual filing, the NSP Companies restated the Interchange Agreement in tariff sheet format pursuant to Order No. 614. The Restated Interchange Agreement was accepted for filing by letter order dated March 20, 2001 in Docket No. ER01-1014-000, effective January 1, 2001. The 2011 annual update, filed on March 30, 2011, submitted the Interchange Agreement in eTariff format. The 2011 update was accepted for filing effective January 1, 2011, by letter order dated May 19, 2011 in Docket Nos. ER11-3234-000 and ER11-3235-000.

B. Statement of Basis for Revised Tariff Sheets

As noted, the annual filing of revised Exhibits VII, VIII and IX is required by Article XIV of the Interchange Agreement which states:

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[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006), *order on reh'g* Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).
[5] The other Xcel Energy Operating Companies are Public Service Company of Colorado and Southwestern Public Service Company.
[6] *See* Article XIV of the Interchange Agreement.

> 14.2 Features Not Automatically Adjusting. It is the intent of the Parties that the values and data specified in Exhibits VII, VIII, IX and X shall not be subject to automatic adjustment and may be changed only by filing revised sheets as a rate change under the Federal Power Act. The Parties contemplate that a revised Exhibit VIII will be filed annually at the end of each calendar year to specify the projected average monthly peak demands for the succeeding calendar year, but that if the projected demands are not available before commencement of the calendar year to which they apply, they may be filed as soon in that calendar year as feasible, with a request, in which all Parties shall concur, that they be made effective as of the first day of the calendar year.

The restatement of Exhibit VII without change is permitted by Exhibit V, Schedule 6, which states in pertinent part:

> If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year,[7] the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination.

Modifications or additions to Exhibit V can be made by a Section 205 filing pursuant to Article XIV of the Interchange Agreement, which states:

> 14.1 Automatically adjusting Features. It is the intent of the Parties that Exhibits I, II, III, IV, V and VI of this Interchange Agreement establish formula-type procedures for developing the amounts of power and energy sales and the unit rates charged for such sales and that the amounts developed under the formula-type procedures set out in those exhibits will adjust automatically from time to time as provided in the exhibits and that no filings will be made at the Federal Energy Regulatory Commission or any successor agency to reflect such automatic

[7] At the time of the certain settlement agreements regarding the 1984 Interchange Agreement filing, the Commission applied a policy of establishing the rate of return on common equity for electric utilities using a formula approach. *See Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420 (May 20, 1985). The 1984 agreement, as amended, thus referred to this process. The Commission has long since ceased this practice.

adjustments. It is the further intent of the Parties that any change in the formula-type procedures set out in the above specified exhibits shall be filed as a rate change under the Federal Power Act.

Section C of this transmittal letter discusses the proposed revisions to the Interchange Agreement exhibit tariff pages in more detail. Redline versions of the complete Exhibit tariff pages showing the proposed revisions to the Interchange Agreement exhibits effective January 1, 2012 are included with this filing as an attachment in the XML package. Appendix A shows the projected impact of the proposed Interchange Agreement revisions on the costs to be allocated to each of the NSP Companies in 2012.

C. Proposed Revised Tariff Sheets Effective January 1, 2012

1. Exhibit VII - Specification of Rate of Return on Common Equity

Exhibit VII sets forth a specification of the rate of return on common equity to determine the overall cost of capital. The NSP Companies are restating the existing Exhibit VII because the Commission has ceased to issue a quarterly adjusted generic rate of return on common equity. The NSP Companies only bear the burden of justifying an increase or decrease in the rate of return on common equity. Here, the NSP Companies are proposing no change to the rate of return on common equity for 2012 from the level accepted in Docket No. ER11-3234-000 and ER11-3235-000, so a statement of impact on each of the NSP Companies is not required.

2. Exhibit VIII – Specification of Average Monthly Peak Demands

Exhibit VIII sets forth the specification of average monthly coincident peak demands for calendar year 2012 for each of the NSP Companies. These coincident peak demands were determined using the same methodology as the previous Exhibit VIII accepted in Docket No. ER11-3234-000 and ER11-3235-000 Coincident peak demands are based upon three years' data consisting of 18 months of actual and 18 months of projected peak demands.

Enclosed with this filing as Appendix A, Page 1 is the calculation of the 2012 36-month coincident peak demand ratios for each of the NSP Companies. These demand ratios are based on the average monthly coincident peak demands for calendar years 2010-2012 as set forth in Exhibit VIII. Appendix A, Page 2, is a statement of the impacts of these coincident peak demands on each of the NSP Companies. While Appendix A provides support of certain calculations in the Interchange Agreement, it is not part of the Interchange Agreement and thus does not need to be filed in e-Tariff format.

3. Exhibit IX – Specification of Depreciation Rates

Exhibit IX sets forth a specification of the depreciation rates currently approved for the NSP Companies. The Minnesota Public Utilities Commission ("MPUC"), the North Dakota Public Service Commission ("NDPSC") and the South Dakota Public Utilities Commission ("SDPUC") approved NSPM's currently effective depreciation rates in the following dockets: MPUC Docket No. E,G002/D-11-144, Annual Review of Remaining Lives 2010, order dated September 8, 2011; MPUC Docket No. E,G002/D-07-1528, Average Service Life and Vintage Group Depreciation Studies for 2007, order dated September 22, 2008; MPUC Docket No. E002/GR-08-1065, Application for Authority to Increase Electric Rates in Minnesota, order dated October 23, 2009; NDPSC Case No. PU-10-657, Application for Authority to Increase Rates for Electric Service in North Dakota, order dated February 29, 2012; and SDPUC Docket No. EL-09-009, Application for Authority to Increase Electric Rates in South Dakota, order dated January 12, 2010. The Public Service Commission of Wisconsin ("PSCW") approved NSPW's depreciation rates in Docket No. 4220-DU-107, order dated August 24, 2011.

Also enclosed with this filing as Appendix A, Page 3 is a statement of the impacts of the depreciation rates on each of the NSP Companies.

4. <u>Exhibit V – Formula Type Procedures for Development of Demand Related Costs</u>

The NSP Companies propose new Exhibit V, Schedule 1.1 and 4.1 to modify the development of demand related costs to add Prefunded Allowance for Funds Used During Construction ("AFUDC") and Construction Work in Progress ("CWIP") for certain transmission projects where the Commission has granted Order No. 679 investment incentives to the determination of the NSP Companies' wholesale transmission revenue requirements. These modifications are necessary to accurately and equitably share transmission investment, as well as transmission revenue and expense incurred under the Midwest Independent Transmission System Operator, Inc. ("MISO") Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"), between the NSP Companies.[8]

Currently, XES and NSPM process the annual transmission revenue requirement ("ATRR") for the NSP Companies' transmission system through the Attachment O-NSP rate formula in the MISO Tariff on file with the Commission. XES and NSPM submit the combined NSP System ATRR to MISO, which uses the NSP System information to derive rates under the MISO Tariff. Depending on the specific project, a portion of the ATRR (including incentives) is recovered through Attachment O-NSP, and a portion is recovered through Attachment GG and MM to the MISO Tariff (for costs subject to regional allocation). NSPM, as agent for the NSP System, then receives MISO transmission revenues as well as the bill from MISO for the joint NSP System costs.

[8] As public utilities subject to comprehensive state rate regulation, most costs associated with NSP System transmission investments are recovered through retail rates calculated using the ratemaking practices in individual states. The proposed changes to the Interchange Agreement herein are oriented at correcting a mismatch created in the calculation of wholesale transmission costs and revenues pursuant to Commission accepted rate formulas.

The Interchange Agreement provides for the sharing of the transmission system revenue requirement by calculating the revenue requirement of each NSP Company's transmission system, and including MISO revenues and expenses as part of the NSPM revenue requirement, because NSPM acts as agent for the entire NSP System with respect to the MISO Tariff. The revenue and expense sharing is based on the relationship of each NSP Company's average system demand relative to the combined NSP System total demand. With respect to the transmission plant investment, the Interchange Agreement revenue requirement sharing is done on a post in-service basis. Thus, CWIP is not included as a component of rate base and AFUDC is not considered as an income statement offset for purposes of the Interchange Agreement. AFUDC is accumulated with the asset cost and included in rate base once the asset is placed in-service.

FERC Order No. 679 provides for incentives to new transmission projects that are approved by FERC as eligible. The NSP Companies were granted incentives for certain transmission projects in 2007.[9] One of the incentives granted is that the average construction expenditure balance for approved projects is permitted to be included as a component of rate base and earn a current return.

In the NSP Companies' 2012 Capital Budget there are four projects under construction (four CapX2020 projects) that have been approved as qualifying to earn a current return on the average expenditure balance pursuant to the Incentives Order. Three of the projects will include investment only by NSPM because they are located in states served by NSPM; and one (Twin Cities – La Crosse) will include investments by both NSPM and NSPW. Without modifications to the Interchange Agreement transmission rate base calculation, an imbalance is created in the Interchange Agreement sharing between NSPM and NSPW. The existing Interchange Agreement formula provides for sharing of net MISO tariff transmission revenue, which includes revenue for projects earning a current return on CWIP under Attachment O-NSP, but does not provide for the sharing of investment costs of these projects during construction.

To correct this imbalance, the NSP Companies request that the rate base calculations for each NSP Company be modified to include the same average construction balance by project used in the development of the MISO Attachment O-NSP, Attachment GG and Attachment MM ATRR as a component of rate base, net of the portion billed back to the NSP System. This change will result in the accurate and equitable cost sharing in both the Interchange Agreement and the

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[9] *Xcel Energy Services, Inc.*, Order Granting Incentives, and Accepting Proposed Rate Formula Modifications, Subject to Conditions, 121 FERC ¶ 61,284 (2007) ("Incentives Order"). The projects granted incentives were the Chisago-Apple River 115/161 kV project, the Buffalo Ridge Incremental Generation Outlet ("BRIGO") 115 kV projects, and four 345 kV or 230 kV projects where NSPM and/or NSPW will invest as part of the CapX2020 initiative. The Chisago-Apple River and BRIGO projects are in service, and the first segment of the first CapX2020 project (the Monticello to St. Cloud segment of the Fargo – Monticello project) was placed in service in December 2012. The Bemidji – Grand Rapids project is now in construction; the other projects remain in state regulatory approval processes or pre-construction development.

FERC incentive determination included in MISO Tariff net transmission revenues to the NSP System.

Given that a current return is being permitted through the application of the FERC Order No. 679 CWIP incentive, it is not appropriate to include AFUDC in the capital cost of the project once these assets are placed in-service. The Company's practice with respect to assets earning a current return is to record a Pre-funded AFUDC as a direct offset to the AFUDC being computed using the FERC defined AFUDC formula and accumulate this offset in FERC account 253 -- Other Deferred Credits. Once the transmission asset is placed in-service, the liability balance is used to offset the AFUDC included in the plant in-service balance to compensate for the current return that was granted. Finally, the accumulated pre-funded AFUDC is amortized in FERC Account 405 – Amortization of Other Electric Plant over the book life of the asset to offset the book depreciation expense attributable to the AFUDC included in the plant balance for which a current return was granted.

In summary, the NSP Companies request that the capital revenue requirement determination related to the Order No. 679 eligible transmission investments for each NSP Company be modified as follows:

1) Include in rate base the net average construction expenditure balance designated to earn a current return through application of Attachment O-NSP, Attachment GG and Attachment MM of the MISO Tariff, including the Order 679 incentive costs. Each NSP Company records these amounts in FERC Account 107 – Construction Work In Progress.

2) When these specific projects are placed in-service, include as an offset to each NSP Company's rate base the FERC jurisdictional accumulated Pre-funded AFUDC balance in FERC Account 253 and also include as an offset to book depreciation expense the amortization of this balance as recorded in FERC Account 405.

The result of these changes will allow the Interchange Agreement to properly share between NSPM and NSPW the net revenues received from application of FERC Order No. 679 incentives in calculating transmission rates for the NSP System, as well as properly share in the construction related revenue requirement determinations used to generate these MISO Tariff revenues.

Additions have been made to Exhibit V to reflect the addition of Prefunded AFUDC as defined on Exhibit V, Schedule 1.1 and CWIP as defined on Exhibit V, Schedule 4.1. These modifications are necessary to accurately and equitably share transmission revenue requirements between the NSP Companies, and should be accepted for filing.

D. <u>E-Tariff Compliance</u>

As described in further detail in Dockets No. ER11-3234 and ER11-3235, the NSP Companies have chosen NSPM as the party that will submit the Interchange Agreement. NSPW is submitting a tariff record that identifies the Interchange Agreement filed by NSPM as a tariff to which NSPW is a party. The proposed changes to Exhibit V and restatement of the other exhibits are included with this filing as an attachment in the XML package, to be effective January 1, 2012.

E. <u>Request for Acceptance for Filing of Agreement, Request for Waiver</u>

The NSP Companies request the Commission accept the revised tariff sheets for filing effective January 1, 2012. The NSP Companies request a waiver of the Commission's notice requirements pursuant to Part 35, if necessary, as well as any other waivers which may be necessary for the revised tariff sheets to be accepted for filing effective on the date requested.[10]

In *Central Hudson Gas* & *Electric Corporation,*[11] the Commission stated that it would generally grant waivers of the 60-day prior notice requirement for uncontested filings that do not change rates.

Based upon the above, a waiver is appropriate for this filing for the following reasons:

(1) the Interchange Agreement is a longstanding formula rate that only affects the allocation of system costs between two affiliated and regulated electric utilities;

(2) the revised tariff sheets will not directly impact the rates charged to wholesale or retail electric customers of the NSP Companies until more than sixty days after filing;[12]

(3) Section 14.2 of the Interchange Agreement specifically contemplates that revisions may be filed after the start of a calendar year if the projected demands are not available before commencement of the calendar year to which they apply, as occurred here; and

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[10] *See Prior Notice and Filing Requirements under Part II of the Federal Power Act*, Docket No PL93-2-002, which states that a waiver of the 60 day notice period will be granted for certain amendments to pre-existing rate schedules. Specifically, the NSP Companies request waiver of the provisions of Exhibit V of the Agreement, which by its terms would have required the annual update to certain exhibits be submitted by December 15, 2011.

[11] 60 FERC ¶ 61,106 (1992), *reh'g denied* 61 FERC¶ 61,089 (1992).

[12] In Docket No. ER10-992-000, NSPW filed to establish a cost-based formula production rate for sales to its ten (10) wholesale requirements customers. A settlement between the parties was accepted by the Commission by delegated letter order on August 4, 2011. *See Northern States Power Company (Wisconsin),* 136 FERC ¶ 61,082 (Aug. 4, 2011). The revisions to the Interchange Agreement proposed here would not affect the calculation of the rates to the NSPW wholesale customers until July 1, 2012, more than sixty days after filing. The changes would also affect the true-up to 2012 actual costs, effective in 2013. The formula rate process established in Docket No. ER10-992 will allow the NSPW wholesale customers to review and potentially challenge the inclusion of costs included in the formula.

(4) Accepting the tariff changes on the date requested will allow the charges between the NSP Companies to reflect the updated cost allocation formulas for the entire 2012 fiscal year. The Commission has previously accepted the annual revisions to the Interchange Agreement effective January 1 of the filing year even though the revisions were not filed until sometime after January 1.

F. <u>Contents of Filing; Notice; Service</u>

1. <u>NSPM Filing</u>

Pursuant to the Commission's filing requirements and in compliance with the e-Tariff Final Rule, the NSPM filing contains the revised Exhibits as an attachment in the XML package and:

a. This transmittal letter, which includes
   i. Appendix A, Comparison of Costs
   ii. Appendix B, the NSPW Certificate of Concurrence and Concurrence Record;
   iii. Appendix C, the Service List for this filing;

2. <u>NSPW Filing</u>

Pursuant to the Commission's filing requirements and in compliance with the e-Tariff Final Rule, the NSPW filing contains:

a. This transmittal letter, which includes
   i. Appendix A, Comparison of Costs
   ii. Appendix B, the NSPW Certificate of Concurrence and Concurrence Record;
   iii. Appendix C, the Service List, the service list for this filing;

A copy or notice of this filing will be sent by mail or e-mail to: (i) all State Commissions with jurisdiction over the NSP Companies, and (ii) all affected wholesale customers, notifying them where they can download or access a copy of this compliance filing. Appendix C provides the list of State Commissioner and customers to be served notice. The NSP Companies will also provide a courtesy copy of this filing to Ms. Penny Murrell, Director of the Division of Electric Power Regulation – Central. Pursuant to 18 C.F.R. § 35.2(d), a copy of this filing will be available for public inspection at the offices of NSPM at 414 Nicollet Mall, Minneapolis, Minnesota; and NSPW's office at 1414 W. Hamilton Avenue, Eau Claire, Wisconsin.

G. <u>Correspondence and Communications</u>

Please send all communications and correspondence in this docket to:

For NSP-Minnesota:

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H. **Conclusion**

The NSP Companies thus respectfully request the Commission accept the revised tariff sheets to the Interchange Agreement for filing effective January 1, 2012.

Please direct any questions regarding this filing to Mr. Jeff Hafner (612-330-7622), Ms. Anne E. Heuer (612-330-6181) or Ms. Mara N. Koeller (612-215-4605).

Sincerely,

/s/ *James P. Johnson*

James P. Johnson
Assistant General Counsel

Xcel Energy Services Inc., on behalf of
Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation

Enclosures

Specification of Average Monthly Coincidental Peak Demands
2012 Calendar Year

		Minnesota Company			Wisconsin Company		
Year/Month		**Peak Demand MW**	**Transmission Loss Multiplier**	**Distribution Level Demand MW**	**Peak Demand MW**	**Transmission Loss Multiplier**	**Distribution Level Demand MW**
January 2010	A	5,553	0.968	5,375	1,083	0.960	1,040
February	A	5,289	0.968	5,120	1,043	0.960	1,001
March	A	4,852	0.968	4,697	970	0.960	931
April	A	4,826	0.968	4,672	941	0.960	903
May	A	7,141	0.968	6,912	1,241	0.960	1,191
June	A	7,033	0.968	6,808	1,241	0.960	1,191
July	A	7,432	0.968	7,194	1,358	0.960	1,303
August	A	7,675	0.968	7,430	1,353	0.960	1,298
September	A	5,672	0.968	5,490	1,124	0.960	1,079
October	A	5,250	0.968	5,082	961	0.960	923
November	A	5,501	0.968	5,325	1,064	0.960	1,021
December 2010	A	5,641	0.968	5,460	1,136	0.960	1,091
Total 2010		71,864		69,564	13,514		12,973
January 2011	A	5,562	0.968	5,384	1,088	0.960	1,044
February	A	5,468	0.968	5,293	1,092	0.960	1,048
March	A	5,186	0.968	5,020	1,009	0.960	969
April	A	4,776	0.968	4,623	953	0.960	915
May	A	5,224	0.968	5,057	1,057	0.960	1,015
June	A	7,682	0.968	7,436	1,363	0.960	1,309
July	F	7,599	0.968	7,355	1,406	0.960	1,350
August	F	7,396	0.968	7,160	1,336	0.960	1,283
September	F	6,585	0.968	6,375	1,307	0.960	1,255
October	F	5,065	0.968	4,903	1,004	0.960	964
November	F	5,457	0.968	5,282	1,088	0.960	1,045
December 2011	F	5,785	0.968	5,600	1,168	0.960	1,122
Total 2011		71,785		69,488	13,873		13,318
January 2012	F	5,655	0.968	5,474	1,160	0.960	1,114
February	F	5,465	0.968	5,290	1,166	0.960	1,119
March	F	5,235	0.968	5,067	1,001	0.960	961
April	F	4,955	0.968	4,796	1,035	0.960	994
May	F	6,066	0.968	5,872	1,085	0.960	1,041
June	F	7,132	0.968	6,904	1,322	0.960	1,269
July	F	7,125	0.968	6,897	1,329	0.960	1,276
August	F	7,124	0.968	6,896	1,330	0.960	1,277
September	F	6,694	0.968	6,480	1,308	0.960	1,255
October	F	5,106	0.968	4,943	1,017	0.960	976
November	F	5,517	0.968	5,340	1,104	0.960	1,060
December 2012	F	5,841	0.968	5,654	1,189	0.960	1,141
Total 2012		71,915		69,613	14,046		13,484
3 Three Total		215,563	0.968	208,665	41,433	0.960	39,776
			2012 CP Ratio	**0.839899**		**2012 CP Ratio**	**0.160101**

A = Actual
F = Forecast

Northern States Power Companies
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules
Allocation of 2012 Estimated Demand Costs, at Authorized, and Proposed Peaks

	2012 Estimated Demand Costs		
	NSP-M	**NSP-W**	**System**
Production	Demand Costs	Demand Costs	Demand Costs
Fixed Charges-Demand	$610,731,820	$36,681,216	$647,413,036
Fixed Portion of O & M & Capacity Purchases	629,296,936	22,219,655	651,516,591
Total	$1,240,028,756	$58,900,871	$1,298,929,627
Transmission			
Fixed Charges	$216,756,649	$59,125,016	$275,881,665
Fixed Portion of O & M	51,010,003	10,242,013	61,252,016
Net Transmission Expense & Wheeling Revenues	(6,793,360)	n/a	(6,793,360)
Total	$260,973,292	$69,367,029	$330,340,321
Total Estimated Demand Costs	$1,501,002,048	$128,267,900	$1,629,269,948

	Allocate 2012 Demand Costs Using 2011 Authorized CP's		
	NSP-M	**NSP-W**	**System**
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	3.20%	4.00%	
Authorized Demand Loss Multipliers	0.968	0.960	
2011 Authorized CP Ratio	0.838019	0.161981	1.000000
Net Costs using 2011 Authorized CP's - Production	$1,088,527,707	$210,401,920	$1,298,929,627
Net Costs - using 2011 Authorized CP's - Transmission	276,831,465	53,508,856	330,340,321
Total Allocated Demand Costs @ Authorized CP's	$1,365,359,173	$263,910,775	$1,629,269,948

	Allocate 2012 Demand Costs Using 2012 Proposed CP's		
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	3.20%	4.00%	
Authorized Demand Loss Multipliers	0.968	0.960	
2012 Proposed CP Ratio	0.839899	0.160101	1.000000
Net Costs using 2012 Proposed CP's - Production	$1,090,969,695	$207,959,932	$1,298,929,627
Net Costs - using 2012 Proposed CP's - Transmission	277,452,505	52,887,816	330,340,321
Total Allocated Demand Costs @ Proposed CP's	$1,368,422,200	$260,847,748	$1,629,269,948

	Change In Cost of Service		
	NSP-M	**NSP-W**	**System**
Change in Ratios	0.00188	(0.00188)	(0.00000)
Change in Production	$2,441,988	($2,441,988)	($0)
Change in Transmission	621,040	(621,040)	0
Total Change in Cost of Service	$3,063,028	($3,063,028)	($0)

Northern States Power Companies
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules
Effect On 2012 Budget

	NSP(M)	NSP(W)			
Coincident Peaks Ratio	0.839899	0.160101			

Present Depreciation Rates

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	$169,004,351	$141,946,585	$27,057,766	$169,004,351
NSP-W to NSP-M	$12,122,160	$10,181,390	$1,940,770	$12,122,160
Total Production	$181,126,511	$152,127,975	$28,998,536	$181,126,511
Transmission				
NSP-M to NSP-W	$47,851,903	$40,190,765	$7,661,138	$47,851,903
NSP-W to NSP-M	$14,991,744	$12,591,551	$2,400,193	$14,991,744
Total Transmission	$62,843,647	$52,782,316	$10,061,331	$62,843,647
Distribution				
NSP-M to NSP-W	$102,572	$86,150	$16,422	$102,572
NSP-W to NSP-M	$4,380	$3,679	$701	$4,380
Total Distribution	$106,952	$89,829	$17,123	$106,952
General System Control				
NSP-M to NSP-W	$1,377,300	$1,156,793	$220,507	$1,377,300
NSP-W to NSP-M	$567,555	$476,689	$90,866	$567,555
Total General System Control	$1,944,855	$1,633,482	$311,373	$1,944,855
Total	$246,021,965	$206,633,602	$39,388,363	$246,021,965

Proposed Depreciation Rates

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	$178,076,661	$149,566,409	$28,510,252	$178,076,661
NSP-W to NSP-M	$13,131,222	$11,028,900	$2,102,322	$13,131,222
Total Production	$191,207,883	$160,595,309	$30,612,574	$191,207,883
Transmission				
NSP-M to NSP-W	$48,025,927	$40,336,928	$7,688,999	$48,025,927
NSP-W to NSP-M	$15,305,249	$12,854,863	$2,450,386	$15,305,249
Total Transmission	$63,331,176	$53,191,791	$10,139,385	$63,331,176
Distribution				
NSP-M to NSP-W	$102,630	$86,199	$16,431	$102,630
NSP-W to NSP-M	$3,427	$2,878	$549	$3,427
Total Distribution	$106,057	$89,077	$16,980	$106,057
General System Control				
NSP-M to NSP-W	$1,377,300	$1,156,793	$220,507	$1,377,300
NSP-W to NSP-M	$567,555	$476,689	$90,866	$567,555
Total General System Control	$1,944,855	$1,633,482	$311,373	$1,944,855
Total	$256,589,971	$215,509,659	$41,080,312	$256,589,971

Change In Cost of Service

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	$9,072,310	$7,619,824	$1,452,486	$9,072,310
NSP-W to NSP-M	$1,009,062	$847,510	$161,552	$1,009,062
Total Production	$10,081,372	$8,467,334	$1,614,038	$10,081,372
Transmission				
NSP-M to NSP-W	$174,024	$146,163	$27,861	$174,024
NSP-W to NSP-M	$313,505	$263,312	$50,193	$313,505
Total Transmission	$487,529	$409,475	$78,054	$487,529
Distribution				
NSP-M to NSP-W	$58	$49	$9	$58
NSP-W to NSP-M	($953)	($801)	($152)	($953)
Total Distribution	($895)	($752)	($143)	($895)
General System Control				
NSP-M to NSP-W	$0	$0	$0	$0
NSP-W to NSP-M	$0	$0	$0	$0
Total General System Control	$0	$0	$0	$0
Total	$10,568,006	$8,876,057	$1,691,949	$10,568,006

CERTIFICATE OF CONCURRENCE

This is to certify that Northern States Power Company, a Wisconsin corporation, assents to and concurs in the joint rate schedule described below, which Northern States Power Company, a Minnesota corporation, has filed in its Market Tariffs e-tariff database.

Rate Schedule:

Northern States Power Companies
Interchange Agreement

Northern States Power Company, a Wisconsin corporation and a wholly owned subsidiary of Xcel Energy Inc.

By: Donald F. Reck

Title: Director, Government and Regulatory Affairs, Northern States Power Company, a Wisconsin corporation

Dated: March 26, 2012

Northern States Power Company, a Wisconsin corporation
Interchange Agreement

For the terms and conditions and rates for this service, please see the tariff document noted below:

Joint Tariff Name:	Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)
Designated Filing Utility:	Northern States Power Company, a Minnesota corporation
Tariff Program Code:	Federal Power Act Electric (Traditional Cost of Service and Market Based Rates)
Designated Filing Utility Tariff Database:	Market Tariffs
Joint Tariff Description:	Formula Integrated System Cost Allocation Agreement of the NSP Companies

Service List

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Mr. Darrell Nitschke
Executive Secretary and Director of Administration
North Dakota Public Service Commission
State Capital
600 East Boulevard
Bismarck, ND 58505-0480

Ms. Sandra J. Paske
Secretary to the Commission
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
P.O. Box 30221
Lansing, MI 48909

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

Ms. Penny Murrell, Director
Division of Tariffs and Market Development
(Central)
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426

Bangor Municipal Utility
Mr. Steve Baker, Manager
106 15th Ave. N.
P.O. Box 130
Bangor, WI 54814

Barron Light & Water Department
Mr. Rick Jari, Utility Manager
1303 East Division Avenue
Barron, WI 54812

Bloomer Electric Company
Mr. Pete Paulson, Superintendent
1503 Main Street
Bloomer, WI 54724

Cadott Light & Water Department
Ms. Lila McConville, Village President
110 East Central
PO Box 40
Cadott, WI 54727

Cornell Electric Utility
Mr. Dave DeJongh, City Administrator
222 Main Street
PO Box 796
Cornell, WI 54732

Rice Lake Utilities
Mr. Scott Reimer, General Manager
320 W. Coleman Street
Rice Lake, WI 54868

Spooner Municipal Utilities
Mr. Bill Marx, City Coordinator
515 Summit Avenue
PO Box 548
Spooner, WI 54801

Trempealeau Municipal Utilities
Travis Cooke, Village Administrator
24455 East 3rd Avenue
PO Box 247
Trempealeau, WI 54661

Wakefield Municipal Utility
John Siira, City Administrator
311 Sunday Lake Street
Wakefield, MI 49968

Anita Gallucci
Boardman Law Firm
PO Box 927
Madison, WI 53701-0927

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of March 2012, a copy of the foregoing document will be served by First Class U.S. Mail upon all persons shown on the attached service list of State Commissions.

/s/

Susan Nerheim
Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Exhibits

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Electric Construction Work in Progress (Sched. 4.1)		
7.	Rate Base (Total lines 1 through 6)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power relicensing investment recorded in FERC Account 302.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 346.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midwest Independent Transmission System Operator, Inc.'s application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111.

These accounts are classified to the production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service.

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midwest Independent Transmission System Operator Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule G and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\frac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let:
- F = Federal Income Tax Rate
- M = Minnesota State Income Tax Rate
- D = North Dakota State Income Tax Rate
- S = South Dakota State Income Tax Rate
- W = Wisconsin State Income Tax Rate
- MI = Michigan State Single Business Tax Rate
- N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:

M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:

F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:

S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota

M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes

W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes:
1. Investment Tax Credit and Surtax Credits are ignored in all formulas.
2. State Income Taxes are deductible from Federal Taxable Income.
   Federal Income Tax is deductible from North Dakota Taxable Income.
   Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407.

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment.

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment.

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities.

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property and 456 - Other Operating Revenue. These revenues are credited to transmission operating and maintenance expenses.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1. Fuel Expenses (Schedule 1)		
2. Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3. Net Purchased Power Energy Costs (Schedule 3)		
4. Carrying Cost on Fuel Stocks		
4.1 Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5. Total Energy Related Costs (Total lines 1 through 4.1)		

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 11.47%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VIII**

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year ~~2011~~2012 Contract Year

Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	***Total System***
~~2009~~2010	January	~~5663~~5553	~~1173~~1083	~~6836~~6636
	February	~~5424~~5289	~~1126~~1043	~~6550~~6332
	March	~~5151~~4852	~~1048~~970	~~6199~~5822
	April	~~4701~~4826	~~1013~~941	~~5714~~5767
	May	~~5956~~7141	~~999~~1241	~~6955~~8381
	June	~~7098~~7033	~~1388~~1241	~~8486~~8274
	July	~~6279~~7432	~~1117~~1358	~~7396~~8789
	August	~~6862~~7675	~~1251~~1353	~~8113~~9028
	September	~~5994~~5672	~~1071~~1124	~~7065~~6796
	October	~~4858~~5250	~~985~~961	~~5843~~6211
	November	~~5093~~5501	~~1027~~1064	~~6120~~6565
	December	~~5756~~5641	~~1163~~1136	~~6919~~6777
	Total	~~68,836~~71,864	13,~~361~~514	~~82,197~~85,377
~~2010~~	~~January~~	~~5569~~	~~1103~~	~~6672~~
	~~February~~	~~5305~~	~~1062~~	~~6367~~
	~~March~~	~~4868~~	~~987~~	~~5855~~
	~~April~~	~~4842~~	~~963~~	~~5805~~
	~~May~~	~~7157~~	~~1263~~	~~8420~~
	~~June~~	~~7049~~	~~1262~~	~~8311~~
	~~July~~	~~7052~~	~~1330~~	~~8382~~
	~~August~~	~~7072~~	~~1312~~	~~8384~~
	~~September~~	~~6727~~	~~1272~~	~~7998~~
	~~October~~	~~5131~~	~~1022~~	~~6153~~
	~~November~~	~~5484~~	~~1108~~	~~6591~~
	~~December~~	~~5804~~	~~1233~~	~~7037~~
	~~Total~~	~~72,059~~	~~13,916~~	~~85,974~~
2011	January	~~5695~~5562	~~1226~~1088	~~6921~~6650
	February	~~5558~~5468	~~1181~~1092	~~6738~~6560
	March	~~5331~~5186	~~1024~~1009	~~6355~~6195
	April	~~5104~~4776	~~1077~~953	~~6180~~5729
	May	~~6126~~5224	~~1089~~1057	~~7215~~6281
	June	~~7238~~7682	~~1393~~1363	~~8631~~9045
	July	~~7266~~7599	~~1368~~1406	~~8634~~9005
	August	~~7277~~7396	~~1357~~1336	~~8634~~8733
	September	~~6887~~6585	~~1312~~1307	~~8199~~7892
	October	~~5228~~5065	~~1040~~1004	~~6268~~6069
	November	~~5589~~5457	~~1129~~1088	~~6718~~6545
	December	~~5922~~5785	~~1261~~1168	~~7183~~6954
	Total	~~73,222~~71,785	~~14,455~~13,873	~~87,677~~85,658

2012	January	5655	1160	6815
	February	5465	1166	6631
	March	5235	1001	6236
	April	4955	1035	5990
	May	6066	1085	7151
	June	7132	1322	8454
	July	7125	1329	8454
	August	7124	1330	8454
	September	6694	1308	8002
	October	5106	1017	6123
	November	5517	1104	6621
	December	5841	1189	7030
	Total	71,915	14,046	85,961

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2011~~2012 CONTRACT YEAR

The following annual composite depreciation rates are calculated based on the most recent actual depreciation expense accruals and plant balances. The actual depreciation expense is calculated based on the most recent remaining life depreciation studies certified by the respective State Commissions for NSP (Minn) and NSP (Wis). Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~1.66%~~ 2.36%
E312	STEAM	Boiler Plant Equipment	~~3.19%~~ 2.92%
E314	STEAM	Turbogenerator Units	3.~~59%~~14%
E315	STEAM	Accessory Electric Equipment	~~3.45%~~ 2.76%
E316	STEAM	Miscellaneous Power Plant Equipment	2.~~27%~~
E302	NUCLEAR	Franchises & Consents	~~3.27%~~54% 5.09%
E321	NUCLEAR	Structures and Improvements	1.~~46%~~71%
E322	NUCLEAR	Reactor Plant Equipment	~~2.10%~~ 1.83%
E323	NUCLEAR	Turbogenerator Units	~~2.38%~~ 1.83%
E324	NUCLEAR	Accessory Electric Equipment	1.~~43%~~44%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	1.~~22%~~62%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.~~71%~~00%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.00%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	~~0.95%~~ 3.63%
E332	HYDRO	Reservoirs, Dams and Water	~~2.73%~~ 3.05%
E333	HYDRO	Water Wheels, Turbines & Generators	~~4.34%~~ 3.69%
E334	HYDRO	Accessory Electric Equipment	~~2.48%~~ 4.11%

E335	HYDRO	Miscellaneous Power Plant Equipment	~~1.23%~~ 3.57%
E340.1	OTHER	Wind Rights	~~3.66%~~ 5.20%
E341	OTHER	Structures and Improvements	~~2.75%~~ 3.31%
E342	OTHER	Fuel Holders, Producers & Accessories	3.~~88%~~53%
E344	OTHER	Generators	3.~~04%~~97%
E345	OTHER	Accessory Electric Equipment	3.~~26%~~78%
E346	OTHER	Miscellaneous Power Plant Equipment	~~2.79%~~ 3.53%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION

E352	Structures and Improvements	2.~~13%~~56%
*E352	Structures and Improvements-Prod.	2.~~47%~~40%
E353	Station Equipment	2.~~56%~~58%
*E353	Station Equipment-Prod.	2.~~57%~~56%
E354	Towers and Fixtures	2.~~36%~~50%
*E354	Towers and Fixtures-Prod.	~~0.81%~~2.56%
E355	Poles and Fixtures	2.~~42%~~52%
*E355	Poles and Fixtures-Prod.	~~2.37%~~1.50%
E356	Overhead Conductors & Devices	~~3.03%~~2.72%
*E356	Overhead Conductors & Devices-Prod.	2.76%
E357	Underground Conduit	~~1.80%~~2.34%
E358	Underground Conductors & Devices	2.~~48%~~56%

DISTRIBUTION

E361	Structures and Improvements	2.~~86%~~88%
*E361	Structures and Improvements-Prod.	2.89%
E362	Station Equipment	2.~~87%~~84%
*E362	Station Equipment-Prod.	2.~~89~~90%
E364	Poles, Towers and Fixtures	~~4.70~~3.48%
E365	Overhead Conductors and Devices	3.~~69~~16%
E366	Underground Conduit	~~1.95~~2.63%
E367	Underground Conductor and Devices	2.70%
E368	Line Transformers	3.28%
E368	Line ~~Transformers~~	~~2.82%~~
~~E368~~	~~Line~~ Capacitors	3.~~99~~69%
E369	Overhead Services	3.~~35~~39%
E369	Underground Services	3.~~36~~43%
E370	Meters	~~6.67~~4.54%
E370.1	Meters-Old	~~4.99~~3.95%
E373	Street Lighting and Signal Systems	4.~~75~~74%

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.22%
E391	Office Furniture and Equipment	5.56%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	18.00%
E392	Transportation Equipment – Light Truck	9.00%
E392	Transportation Equipment – Trailers	9.00%
E392	Transportation Equipment – Heavy Trucks	7.92%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	6.67%
E394	Hand Held Meter Readers	20.00%
E395	Laboratory Equipment	10.00%
E396	Power Operated Equipment	9.00%
E397	Communication Equipment	11.11%
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

FERC ACCOUNT		DESCRIPTION	***ANNUAL DEPRECIATION*** RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~2.38%~~3.01%
E312	STEAM	Boiler Plant Equipment	3.~~12%~~21%
E314	STEAM	Turbogenerator Units	3.~~07%~~28%
E315	STEAM	Accessory Electric Equipment	3.~~46%~~42%
E316	STEAM	Miscellaneous Power Plant Equipment	3.~~09%~~75%
E302	HYDRO	Franchises & Consents	3.~~49%~~52%
E331	HYDRO	Structures and Improvements	2.~~81%~~87%
E332	HYDRO	Reservoirs, Dams & Water	2.~~68%~~65%
E333	HYDRO	Water Wheels, Turbines & Generators	3.~~15%~~32%
E334	HYDRO	Accessory Electric Equipment	2.~~83%~~93%
E335	HYDRO	Miscellaneous Power Plant Equipment	2.~~51%~~74%
E341	OTHER	Structures and Improvements	~~1.64%~~3.08%
E342	OTHER	Fuel Holders, Producers & Accessories	3.~~67%~~37%
E343	OTHER	Prime Movers	~~1.57%~~2.86%
E344	OTHER	Generators	~~2.55%~~3.49%
E345	OTHER	Accessory Electric Equipment	~~3.33%~~4.70%
E346	OTHER	Miscellaneous Power Plant Equipment	6.~~86%~~76%
TRANSMISSION			
E352		Structures and Improvements	2.~~52%~~98%
*E352		Structures and Improvements-Prod.	~~2.17%~~3.04%
E353		Station Equipment	3.~~16%~~13%
*E353		Station Equipment-Prod.	3.~~29%~~26%
E354		Towers and Fixtures	2.~~30%~~69%
E355		Poles and Fixtures	2.98%
E356		Overhead Conductors & Devices	3.~~12%~~01%
E357		Underground Conduit	~~.25%~~2.84%
E358		Underground Conductors & Devices	~~.35%~~2.89%
E359		Roads and Trails	2.~~50%~~27%

DISTRIBUTION

E361	Structures and Improvements	2.~~56%~~85%
*E361	Structures and Improvements-Prod.	1.66%
E362	Station Equipment	3.12%
*E362	Station Equipment-Prod.	2.~~63~~47%
E364	Poles, Towers and Fixtures	3.~~10~~71%
E365	Overhead Conductors and Devices	3.42%
E366	Underground Conduit	3.15%
E367	Underground Conductor and Devices	3.14%
E368	Line Transformers	3.56%
E368	Line Transformers/Other	3.56%
E368	Line Capacitors	3.59%
E369	Overhead Services	3.97%
E369	Underground Services	3.97%
E370	Meters	4.20%
E370.1	Meters-Old	4.30%
E370.2	Meters-AMR	~~3.44~~4.74%
E371	Customer Installations	2.~~62~~55%
E373	Street Lighting	~~2.58%~~
		~~2.99%~~
		~~2.99%~~
		~~3.01%~~
		~~4.34%~~
		~~4.36%~~
		~~4.58%~~
		~~5.35%~~
		~~7.20%~~
		~~.17%~~
		6.~~41%~~38%

ELECTRIC GENERAL

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.86%
E391	Office Furniture and Equipment	5.00%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	12.86%
E392	Transportation Equipment – Light Truck	12.86%
E392	Transportation Equipment – Heavy Truck	9.00%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	5.00%
E395	Laboratory Equipment	5.00%
E396	Power Operated Equipment	7.50%
E397	Communication Equipment	6.67%
E397	Communication Equipment-EMS	9.09%
E398	Miscellaneous Equipment	5.00%

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

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<u>Exhibits</u>

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.968 for NSP(Minn)
0.960 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the previous month. The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.967 for NSP(Minn)
0.938 for NSP(Wis)

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Electric Construction Work in Progress (Sched. 4.1)		
7.	Rate Base (Total lines 1 through 6)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power relicensing investment recorded in FERC Account 302.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 346.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midwest Independent Transmission System Operator, Inc.'s application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111.

These accounts are classified to the production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service.

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midwest Independent Transmission System Operator Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule G and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of the following year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year following the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\frac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let:
F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:
F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes:
1. Investment Tax Credit and Surtax Credits are ignored in all formulas.
2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407.

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment.

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment.

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities.

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property and 456 - Other Operating Revenue. These revenues are credited to transmission operating and maintenance expenses.

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

		NSP (Minn)	NSP(Wis)
1.	Fuel Expenses (Schedule 1)		
2.	Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3.	Net Purchased Power Energy Costs (Schedule 3)		
4.	Carrying Cost on Fuel Stocks		
4.1	Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5.	Total Energy Related Costs (Total lines 1 through 4.1)		

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 11.47%.

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2012 Contract Year

Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	***Total System***
2010	January	5553	1083	6636
	February	5289	1043	6332
	March	4852	970	5822
	April	4826	941	5767
	May	7141	1241	8381
	June	7033	1241	8274
	July	7432	1358	8789
	August	7675	1353	9028
	September	5672	1124	6796
	October	5250	961	6211
	November	5501	1064	6565
	December	5641	1136	6777
	Total	71,864	13,514	85,377
2011	January	5562	1088	6650
	February	5468	1092	6560
	March	5186	1009	6195
	April	4776	953	5729
	May	5224	1057	6281
	June	7682	1363	9045
	July	7599	1406	9005
	August	7396	1336	8733
	September	6585	1307	7892
	October	5065	1004	6069
	November	5457	1088	6545
	December	5785	1168	6954
	Total	71,785	13,873	85,658
2012	January	5655	1160	6815
	February	5465	1166	6631
	March	5235	1001	6236
	April	4955	1035	5990
	May	6066	1085	7151
	June	7132	1322	8454
	July	7125	1329	8454
	August	7124	1330	8454
	September	6694	1308	8002
	October	5106	1017	6123
	November	5517	1104	6621
	December	5841	1189	7030
	Total	71,915	14,046	85,961

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2012 CONTRACT YEAR

The following annual composite depreciation rates are calculated based on the most recent actual depreciation expense accruals and plant balances. The actual depreciation expense is calculated based on the most recent remaining life depreciation studies certified by the respective State Commissions for NSP (Minn) and NSP (Wis). Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION ***RATE PERCENT***
PRODUCTION			
E311	STEAM	Structures and Improvements	2.36%
E312	STEAM	Boiler Plant Equipment	2.92%
E314	STEAM	Turbogenerator Units	3.14%
E315	STEAM	Accessory Electric Equipment	2.76%
E316	STEAM	Miscellaneous Power Plant Equipment	2.54%
E302	NUCLEAR	Franchises & Consents	5.09%
E321	NUCLEAR	Structures and Improvements	1.71%
E322	NUCLEAR	Reactor Plant Equipment	1.83%
E323	NUCLEAR	Turbogenerator Units	1.83%
E324	NUCLEAR	Accessory Electric Equipment	1.44%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	1.62%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning FERC Wisconsin Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.00%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	3.63%
E332	HYDRO	Reservoirs, Dams and Water	3.05%
E333	HYDRO	Water Wheels, Turbines & Generators	3.69%
E334	HYDRO	Accessory Electric Equipment	4.11%
E335	HYDRO	Miscellaneous Power Plant Equipment	3.57%
E340.1	OTHER	Wind Rights	5.20%
E341	OTHER	Structures and Improvements	3.31%
E342	OTHER	Fuel Holders, Producers & Accessories	3.53%
E344	OTHER	Generators	3.97%
E345	OTHER	Accessory Electric Equipment	3.78%
E346	OTHER	Miscellaneous Power Plant Equipment	3.53%

TRANSMISSION

E352	Structures and Improvements	2.56%
*E352	Structures and Improvements-Prod.	2.40%
E353	Station Equipment	2.58%
*E353	Station Equipment-Prod.	2.56%
E354	Towers and Fixtures	2.50%
*E354	Towers and Fixtures-Prod.	2.56%
E355	Poles and Fixtures	2.52%
*E355	Poles and Fixtures-Prod.	1.50%
E356	Overhead Conductors & Devices	2.72%
*E356	Overhead Conductors & Devices-Prod.	2.76%
E357	Underground Conduit	2.34%
E358	Underground Conductors & Devices	2.56%

DISTRIBUTION

E361	Structures and Improvements	2.88%
*E361	Structures and Improvements-Prod.	2.89%
E362	Station Equipment	2.84%
*E362	Station Equipment-Prod.	2.90%
E364	Poles, Towers and Fixtures	3.48%
E365	Overhead Conductors and Devices	3.16%
E366	Underground Conduit	2.63%
E367	Underground Conductor and Devices	2.70%
E368	Line Transformers	3.28%
E368	Line Capacitors	3.69%
E369	Overhead Services	3.39%
E369	Underground Services	3.43%
E370	Meters	4.54%
E370.1	Meters-Old	3.95%
E373	Street Lighting and Signal Systems	4.74%

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.22%
E391	Office Furniture and Equipment	5.56%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	18.00%
E392	Transportation Equipment – Light Truck	9.00%
E392	Transportation Equipment – Trailers	9.00%
E392	Transportation Equipment – Heavy Trucks	7.92%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	6.67%
E394	Hand Held Meter Readers	20.00%
E395	Laboratory Equipment	10.00%
E396	Power Operated Equipment	9.00%
E397	Communication Equipment	11.11%
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES

NSP(Wis):

FERC ACCOUNT		DESCRIPTION	***ANNUAL DEPRECIATION*** RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	3.01%
E312	STEAM	Boiler Plant Equipment	3.21%
E314	STEAM	Turbogenerator Units	3.28%
E315	STEAM	Accessory Electric Equipment	3.42%
E316	STEAM	Miscellaneous Power Plant Equipment	3.75%
E302	HYDRO	Franchises & Consents	3.52%
E331	HYDRO	Structures and Improvements	2.87%
E332	HYDRO	Reservoirs, Dams & Water	2.65%
E333	HYDRO	Water Wheels, Turbines & Generators	3.32%
E334	HYDRO	Accessory Electric Equipment	2.93%
E335	HYDRO	Miscellaneous Power Plant Equipment	2.74%
E341	OTHER	Structures and Improvements	3.08%
E342	OTHER	Fuel Holders, Producers & Accessories	3.37%
E343	OTHER	Prime Movers	2.86%
E344	OTHER	Generators	3.49%
E345	OTHER	Accessory Electric Equipment	4.70%
E346	OTHER	Miscellaneous Power Plant Equipment	6.76%
TRANSMISSION			
E352		Structures and Improvements	2.98%
*E352		Structures and Improvements-Prod.	3.04%
E353		Station Equipment	3.13%
*E353		Station Equipment-Prod.	3.26%
E354		Towers and Fixtures	2.69%
E355		Poles and Fixtures	2.98%
E356		Overhead Conductors & Devices	3.01%
E357		Underground Conduit	2.84%
E358		Underground Conductors & Devices	2.89%
E359		Roads and Trails	2.27%

DISTRIBUTION

E361	Structures and Improvements	2.85%
*E361	Structures and Improvements-Prod.	1.66%
E362	Station Equipment	3.12%
*E362	Station Equipment-Prod.	2.47%
E364	Poles, Towers and Fixtures	3.71%
E365	Overhead Conductors and Devices	3.42%
E366	Underground Conduit	3.15%
E367	Underground Conductor and Devices	3.14%
E368	Line Transformers	3.56%
E368	Line Transformers/Other	3.56%
E368	Line Capacitors	3.59%
E369	Overhead Services	3.97%
E369	Underground Services	3.97%
E370	Meters	4.20%
E370.1	Meters-Old	4.30%
E370.2	Meters-AMR	4.74%
E371	Customer Installations	2.55%
E373	Street Lighting	6.38%

ELECTRIC GENERAL

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.86%
E391	Office Furniture and Equipment	5.00%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	12.86%
E392	Transportation Equipment – Light Truck	12.86%
E392	Transportation Equipment – Heavy Truck	9.00%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	5.00%
E395	Laboratory Equipment	5.00%
E396	Power Operated Equipment	7.50%
E397	Communication Equipment	6.67%
E397	Communication Equipment-EMS	9.09%
E398	Miscellaneous Equipment	5.00%

SPECIFICATIONS OF DEMAND AND ENERGY CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Northern States Power Company,
a Minnesota corporation
Northern States Power Company,
a Wisconsin corporation
Docket No. ER12-1348-000

May 23, 2012

Xcel Energy Services Inc.
414 Nicollet Mall – 5th Floor
Minneapolis, MN 55401

Attention: James P. Johnson
Assistant General Counsel

Reference: Annual Update to Interchange Agreement

Dear Mr. Johnson:

On March 26, 2012, Xcel Energy Services Inc. filed a revised Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy (Interchange Agreement) between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin).[1] The request for waiver of the 60-day prior notice requirements pursuant to section 35.11 of the Commission's regulations (18 C.F.R. § 35.11) is granted.[2] The tariff record is accepted effective January 1, 2012, as requested.[3]

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[1] Northern States Power Company (Minnesota) is the designated filer. Northern States Power Company (Wisconsin) previously submitted a concurrence record for the Interchange Agreement in Docket No. ER11-3235-000.

[2] *Central Hudson Gas and Electric Company, et al.*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 (1992), and *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, *clarified*, 65 FERC ¶ 61,081 (1993).

[3] Northern States Power Company, a Minnesota corporation, FERC FPA Electric Tariff, Market Tariffs, Exhibits, 0.1.0.

The filing was noticed on March 26, 2012, with comments due on or before April 16, 2012. None was filed. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your Company.

This action is taken pursuant to the authority delegated to the Director, Division of Electric Power Regulation - Central, under 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power
Regulation - Central