Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401

May 27, 2021

Via E-Tariff

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 and Northern States Power Company, a Wisconsin corporation***
Amendment to Interchange Agreement Annual Update
Docket No. ER21-1401-000

Dear Ms. Bose:

On March 15, 2021, Xcel Energy Services Inc. ("XES"),[1] on behalf of Northern States Power Company, a Minnesota corporation ("NSPM"), and Northern States Power Company, a Wisconsin corporation ("NSPW") (jointly the "NSP Companies"), submitted to the Federal Energy Regulatory Commission ("Commission") in the above-referenced docket 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") to become effective as of January 1, 2021 (the "March 15 Filing").

On May 5, 2021, pursuant to 18 C.F.R. § 35.17(b) (2020) of the Commission's regulations and other FERC guidance,[2] the NSP Companies filed a Tariff Record with an effective date of "12/31/9998" for the purpose of deferring the need for the Commission to take action on the NSP Companies' filing.

In this filing, the NSP Companies amend the March 15 Filing to reflect revised transmission loss factors from its 2020 system loss study due to an administrative error in the calculation of the four-year average transmission loss factors. Although the NSP Companies are filing revisions to all of the Exhibits to the Interchange Agreement to comply with the Commission's eTariff processes (since the Interchange Agreement has not been filed in section format), only the following Interchange Agreement exhibits are being revised in this filing:

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[1] XES is the centralized service company for the Xcel Energy Inc. holding company system and represents the NSP Companies and the other Xcel Energy operating companies in proceedings before the Commission.

[2] *See Requirements for Filings By Public Utilities Seeking to Extend the Date for Commission Action on Statutory Filings* (posted at http://www.ferc.gov/docs-filing/etariff/comm-order/extend-date.pdf).

Exhibit I
Exhibit II
Exhibit III
Exhibit IV

Marked versions of the complete Exhibit tariff pages showing the proposed revisions to the Interchange Agreement are included with this filing as an attachment in the XML package. The NSP Companies propose the revised tariff sheets be effective January 1, 2021 as requested in the March 15 Filing, and respectfully request any waiver necessary for the tariff sheets to be effective on the date requested, so the NSP Companies' integrated electric system (the "NSP System") cost allocations may be in effect for the full 2021 fiscal year.

A. Proposed Revised Tariff Sheets Effective January 1, 2021

Exhibits I, II, III and IV – Updated Amended Transmission Loss Multipliers

In the March 15 Filing, the NSP Companies filed an electrical loss analysis which updated the demand and energy transmission loss ratios ("Transmission Loss Multipliers") used in the Interchange Agreement for allocation of demand and energy between the NSP Companies. In this filing, the NSP Companies amend the March 15 Filing to correct for an administrative error in the calculation of the four-year average (2016-2019) transmission loss factors and resulting impact on the calculation of the Transmission Loss Multipliers. The current transmission loss factors accepted in Docket No. ER19-1340-000 and the proposed transmission loss factors from the March 15 Filing and amended in this filing are as follows:

	Current		Proposed (3/15/2021)		Amended (5/27/2021)	
Loss Ratios	NSPM	NSPW	NSPM	NSPW	NSPM	NSPW
Demand	3.3%	5.5%	3.7%	4.8%	3.6%	4.8%
Energy	3.4%	5.2%	3.6%	4.9%	3.7%	4.7%

The demand and energy Transmission Loss Multipliers stated in the Interchange Agreement Exhibits are calculated by subtracting 1 minus the applicable loss ratio. For example, the amended NSPW demand loss multiplier equals 1.0 minus 0.048, or 0.952. The current Transmission Loss Multipliers accepted in Docket No. ER19-1340-000 and the proposed Transmission Loss Multipliers from the March 15 Filing and amended in this filing are as follows:

	Current		Proposed (3/15/2021)		Amended (5/27/2021)	
Loss Multipliers	NSPM	NSPW	NSPM	NSPW	NSPM	NSPW
Demand	0.967	0.945	0.963	0.952	0.964	0.952
Energy	0.966	0.948	0.964	0.951	0.963	0.953

The impact of the amended Transmission Loss Multipliers is shown in Appendix A. Appendix B is a copy of the updated loss study in support of the proposed transmission loss ratio and transmission loss multipliers.

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

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

a. This transmittal letter;

b. The proposed revised Interchange Agreement Exhibits in clean format as an attachment in the XML package, with a January 1, 2021 requested effective date;

c. The proposed revised Interchange Agreement Exhibits in marked format, showing changes to the exhibits since they were accepted for filing in Docket No. ER20-1249-000;

d. The following appendices:

 i. Appendix A, which sets forth the proposed 2021 36-month coincident peak demands, the financial impact of these proposed demands on each of the NSP Companies, and a statement of impact regarding depreciation rates on each of the NSP Companies; and

 ii. Appendix B, a copy of the 2020 NSP System loss study supporting the proposed transmission loss ratios and the methodology used to calculate the proposed ratios.

A copy or electronic notice of this filing will be sent by e-mail to all State Commissions with jurisdiction over the NSP Companies and the official service list established by the Commission for the above-captioned docket. The NSP Companies will also provide a courtesy copy of this filing to the Director, Division of Electric Power Regulation – Central. A copy of this filing will be available for public inspection at the offices of NSPM at 414 Nicollet Mall – 401—7th , Minneapolis, Minnesota; and NSPW's office at 1414 W. Hamilton Avenue, Eau Claire, Wisconsin

C. <u>Conclusion</u>

The NSP Companies respectfully request the Commission accept the revised tariff sheets to the Interchange Agreement for filing effective January 1, 2021. Please direct any questions regarding this filing to the undersigned (715-737-2417) or Mr. David E. Pettit (303-294-2599).

Sincerely,

/s/ *Karen L. Everson*

Karen L. Everson
Director, Utility Accounting
Xcel Energy Services Inc., on behalf of
Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Commission in this proceeding.

Dated at Minneapolis, Minnesota this XXth day of May, 2021.

/s/ *Paget Pengelly*
Paget Pengelly
Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-6892
paget.j.pengelly@xcelenergy.com

Northern States Power Companies **Appendix A**
Interchange Agreement **Page 1**
Comparison of Costs - Present and Proposed Rate Schedules – Amendment to Interchange Agreement – Annual Update

Specification of Average Monthly Coincidental Peak Demands
2021 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 2019	A	5,523	0.964	5,324	1,156	0.952	1,101
February	A	5,138	0.964	4,953	1,082	0.952	1,030
March	A	5,133	0.964	4,948	1,097	0.952	1,045
April	A	4,679	0.964	4,510	936	0.952	892
May	A	5,167	0.964	4,981	989	0.952	941
June	A	6,388	0.964	6,158	1,065	0.952	1,014
July	A	7,469	0.964	7,200	1,305	0.952	1,242
August	A	6,539	0.964	6,304	1,209	0.952	1,151
September	A	6,619	0.964	6,381	1,093	0.952	1,040
October	A	4,535	0.964	4,372	938	0.952	893
November	A	5,026	0.964	4,845	1,064	0.952	1,013
December 2019	A	5,196	0.964	5,009	1,097	0.952	1,045
Total 2019		67,413		64,986	13,032		12,407
January 2020	A	5,093	0.964	4,909	1,077	0.952	1,025
February	A	4,996	0.964	4,816	1,094	0.952	1,042
March	A	4,593	0.964	4,428	949	0.952	904
April	A	4,244	0.964	4,091	852	0.952	811
May	A	5,120	0.964	4,935	986	0.952	939
June	A	6,925	0.964	6,676	1,191	0.952	1,134
July	F	6,687	0.964	6,446	1,237	0.952	1,178
August	F	6,648	0.964	6,408	1,276	0.952	1,215
September	F	5,992	0.964	5,776	1,093	0.952	1,040
October	F	4,339	0.964	4,183	900	0.952	857
November	F	4,418	0.964	4,259	950	0.952	905
December 2020	F	4,845	0.964	4,671	1,061	0.952	1,010
Total 2020		63,900		61,599	12,666		12,058
January 2021	F	4,867	0.964	4,692	1,057	0.952	1,006
February	F	4,701	0.964	4,532	1,017	0.952	968
March	F	4,543	0.964	4,379	962	0.952	916
April	F	4,151	0.964	4,001	875	0.952	833
May	F	5,222	0.964	5,034	1,015	0.952	966
June	F	6,810	0.964	6,565	1,254	0.952	1,194
July	F	6,812	0.964	6,567	1,263	0.952	1,203
August	F	6,771	0.964	6,527	1,305	0.952	1,242
September	F	6,126	0.964	5,905	1,121	0.952	1,068
October	F	4,469	0.964	4,308	931	0.952	886
November	F	4,554	0.964	4,390	983	0.952	936
December 2021	F	4,982	0.964	4,803	1,095	0.952	1,042
Total 2021		64,008		61,703	12,879		12,261
3 Three Total		195,320	0.964	188,289	38,577	0.952	36,725
			2021 CP Ratio	**0.836786**		**2021 CP Ratio**	**0.163214**

A = Actual
F = Forecast

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Comparison of Costs - Present and Proposed Rate Schedules
Allocation of 2021 Estimated Demand Costs, at Authorized, and Proposed Peaks
IMPACT OF CHANGE IN ANNUAL DEMAND ALLOCATORS – Amendment to Interchange Agreement – Annual Update

	2021 Estimated Demand Costs		
	NSP-M	**NSP-W**	**System**
Production	Demand Costs	Demand Costs	Demand Costs
Fixed Charges-Demand	$940,541,581	$34,439,808	$974,981,389
Fixed O & M, Capacity Purchases, & Other	601,456,368	22,447,911	623,904,279
Total	$1,541,997,949	$56,887,719	$1,598,885,668
Transmission			
Fixed Charges	$345,310,177	$129,015,133	$474,325,309
Fixed Portion of O & M	47,206,590	14,548,830	61,755,420
Net Transmission Expense & Wheeling Revenues	(20,433,914)	n/a	(20,433,914)
Total	$372,082,853	$143,563,963	$515,646,816
Total Estimated Demand Costs	$1,914,080,802	$200,451,681	$2,114,532,484

	Allocate 2021 System Demand Costs Using 2020 Authorized CP's		
	NSP-M	**NSP-W**	**System**
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	3.30%	5.50%	
Authorized Demand Loss Multipliers	0.967	0.945	
2020 Authorized CP Ratio	0.838543	0.161457	1.000000
Net Costs using 2020 Authorized CP's - Production	$1,340,734,385	$258,151,283	$1,598,885,668
Net Costs using 2020 Authorized CP's - Transmission	432,392,028	83,254,788	515,646,816
Total Allocated Demand Costs @ Authorized CP's	$1,773,126,412	$341,406,071	$2,114,532,484

	Allocate 2021 System Demand Costs Using 2021 Proposed CP's		
Coincident Peak Ratios (CP's)			
Proposed Transmission Loss Rate	3.60%	4.80%	
Proposed Demand Loss Multipliers	0.964	0.952	
2021 Proposed CP Ratio	**0.836786**	**0.163214**	**1.000000**
Net Costs using 2021 Proposed CP's - Production	$1,337,925,143	$260,960,525	$1,598,885,668
Net Costs using 2021 Proposed CP's - Transmission	431,486,036	84,160,779	515,646,816
Total Allocated Demand Costs @ Proposed CP's	$1,769,411,179	$345,121,305	$2,114,532,484

	Change In Cost of Service (with Proposed Loss Multipliers)		
	NSP-M	**NSP-W**	**System**
Change in Ratios	(0.001757)	0.001757	0.00000
Change in Production	($2,809,242)	$2,809,242	$0
Change in Transmission	(905,991)	905,991	0
Total Change in Cost of Service	($3,715,234)	$3,715,234	$0

	Total Change In Cost of Service		
	NSP-M	**NSP-W**	**System**
Impact of Change in CP Demands	($697,796)	$697,796	$0
Impact of Change in Loss Multipliers	($3,017,438)	$3,017,438	$0
Total Impact of Change in CP Demands & Loss Multipliers	**($3,715,234)**	**$3,715,234**	**$0**

As included in March 15, 2021 Filing	**Total Change In Cost of Service**		
	NSP-M	**NSP-W**	**System**
Impact of Change in CP Demands	($697,796)	$697,796	$0
Impact of Change in Loss Multipliers	($3,317,701)	$3,317,701	($0)
Total Impact of Change in CP Demands & Loss Multipliers	**($4,015,497)**	**$4,015,497**	**$0**

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Comparison of Costs - Present and Proposed Rate Schedules
Effect On 2021 Budget – Amendment to Interchange Agreement – Annual Update

	NSP(M)	NSP(W)			
Coincident Peaks Ratio	0.836786	0.163214			

		Present Depreciation Rates		
Production		NSP-M	NSP-W	System
NSP-M to NSP-W	$415,372,805	$347,578,148	$67,794,657	$415,372,805
NSP-W to NSP-M	20,607,318	17,243,915	3,363,403	20,607,318
Total Production	$435,980,123	$364,822,063	$71,158,060	$435,980,123
Transmission				
NSP-M to NSP-W	$80,143,271	$67,062,767	$13,080,504	$80,143,271
NSP-W to NSP-M	37,131,833	31,071,398	6,060,435	37,131,833
Total Transmission	$117,275,104	$98,134,165	$19,140,939	$117,275,104
Distribution				
NSP-M to NSP-W	$78,422	$65,622	$12,800	$78,422
NSP-W to NSP-M	3,414	2,857	557	3,414
Total Distribution	$81,836	$68,479	$13,357	$81,836
General System Control				
NSP-M to NSP-W	$2,602,785	$2,177,974	$424,811	$2,602,785
NSP-W to NSP-M	429,021	358,999	70,022	429,021
Total General System Control	$3,031,806	$2,536,973	$494,833	$3,031,806
Total	$556,368,869	$465,561,680	$90,807,189	$556,368,869

		Proposed Depreciation Rates		
Production		NSP-M	NSP-W	System
NSP-M to NSP-W	$447,928,750	$374,820,507	$73,108,243	$447,928,750
NSP-W to NSP-M	22,172,806	18,553,894	3,618,912	22,172,806
Total Production	$470,101,556	$393,374,401	$76,727,155	$470,101,556
Transmission				
NSP-M to NSP-W	$80,143,271	$67,062,767	$13,080,504	$80,143,271
NSP-W to NSP-M	37,131,833	31,071,398	6,060,435	37,131,833
Total Transmission	$117,275,104	$98,134,165	$19,140,939	$117,275,104
Distribution				
NSP-M to NSP-W	$78,955	$66,068	$12,887	$78,955
NSP-W to NSP-M	3,414	2,857	557	3,414
Total Distribution	$82,369	$68,925	$13,444	$82,369
General System Control				
NSP-M to NSP-W	$2,602,785	$2,177,974	$424,811	$2,602,785
NSP-W to NSP-M	429,021	358,999	70,022	429,021
Total General System Control	$3,031,806	$2,536,973	$494,833	$3,031,806
Total	$590,490,835	$494,114,464	$96,376,371	$590,490,835

		Change In Cost of Service		
Production		NSP-M	NSP-W	System
NSP-M to NSP-W	$32,555,945	$27,242,359	$5,313,586	$32,555,945
NSP-W to NSP-M	1,565,488	1,309,979	255,509	1,565,488
Total Production	$34,121,433	$28,552,338	$5,569,095	$34,121,433
Transmission				
NSP-M to NSP-W	$0	$0	$0	$0
NSP-W to NSP-M	0	0	0	0
Total Transmission	$0	$0	$0	$0
Distribution				
NSP-M to NSP-W	$533	$446	$87	$533
NSP-W to NSP-M	0	0	0	0
Total Distribution	$533	$446	$87	$533
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	$34,121,966	$28,552,784	$5,569,182	$34,121,966

Change Included in March 15, 2021 Filing	$34,121,966	$28,547,938	$5,574,028	$34,121,966
Difference	$0	$4,846	($4,846)	$0

NSP Companies (NSPM/NSPW) 2020 Interchange Agreement Transmission Loss Study

Xcel Energy Services; Transmission Planning.

Craig Wrisley

Dylan Kohl

Jason Standing

Aug 12, 2020
(Revised April 26, 2021)

Contents.

1.0: Scope of Study.

This study seeks to recommend revised demand and energy transmission loss percentages for Northern States Power Company Minnesota (“NSPM”) and Northern States Power Company Wisconsin (“NSPW”) (collectively “NSP” or “NSP Companies”) which are used to allocate costs in the Interchange Agreement. The losses in this study are based upon the data that has been collected from NSP’s state estimator for years 2016 through 2019.

2.0: Methodology.

This study uses NSP hourly state estimator data to calculate both the demand and energy losses on NSP’s transmission system. The state estimator has the ability to provide over 8000 states of data for calculating losses, which is significantly more than the amount possible during an offline study. The demand losses are defined as the losses that occur on NSP’s transmission system during the monthly peak hourly load, whereas energy losses are defined as the summation of all hourly losses in a given month. This analysis was performed for each month in the years 2016 through 2019 for which data has been collected. To calculate the required percentages, these losses will then be divided by NSP’s local balancing authority (LBA) load. In the case of demand losses, the load will be the peak hour load while the energy loss will be the summation of MW-Hr loads in the given month. Not all the loads in NSP’s LBA are NSP’s native load. Loads from Great River Energy (GRE) and Dairyland Power Cooperative (DPC) are within NSP’s LBA. Great River Energy is an electric cooperative based in Minnesota while Dairyland Power Cooperative is an electric cooperative based in Wisconsin. These loads also create losses on the transmission system and need to be added to NSP’s load to obtain the correct loss percentages. These loads will be added to the respective company divisors; GRE to NSPM and DPC to NSPW.

3.0: Description of Losses.

Losses are the portion of energy lost on the transmission system in the form of heat. There are several contributing factors to losses on the transmission system due to various factors listed below:

- NSP Local Balancing Authority electrical demand
- Generation Dispatch – the location and hours a generator operates will influence transmission losses
- Line outages – a planned or unexpected outage of a line can change the loading on the remaining system

- New facilities – new lines, substations, and generation can change the loading on the transmission and distribution system
- Power factor – power factor influences the current on the line, and therefore, the losses
- Temperature – the resistance of a conductor increases as the temperature increases. The conductor temperature is influenced by the combined effect of the ambient air temperature and wind velocity as well as the heat generated due to current flow in the conductor

4.0: Description of Local Balancing Authority.

A Balancing Authority Area, formerly known as a Control Area, is defined as all generators, loads, and transmission that are within a metered boundary. The Balancing Authority (BA) is the entity responsible for the regulation and stabilization for the grid frequency by balancing electric generation and electric demand. Currently, Midcontinent Independent System Operator (MISO) is the balancing authority for all MISO members, including NSP. However, NSP Companies are a party to the MISO's Balancing Authority Agreement as a Local Balancing Authority (LBA). This arrangement splits balancing authority responsibilities between MISO and NSP. NSP's LBA for this study will be defined as all generators, loads, and transmission that are within NSP's metered boundary.

5.0: Description of the State Estimator.

A State Estimator (SE) provides a complete complex voltage solution for the network model which is used for further analysis and computations. The SE solution is based on real-time measurements, scheduled load and generation, and dispatcher/operator entries. SE is performed several times per hour and provides a continuous snapshot of the network.

The Energy Management System (EMS) has real-time measurements received from the field through telemetry. The real-time measurements are imperfect but redundant. This redundancy permits the SE to determine an estimate for the voltage magnitude and angles for the observable portion of the network model which best matches the information given by the unfiltered measurements. For that portion of the network model that is unobservable (real-time measurements not available), load and generation is scheduled. These scheduled values along with any dispatcher/operator entries are used by the SE to determine a voltage magnitude and angle estimate for the unobservable portion of the network model.

The State Estimator accepts node voltage measurements, branch ampere magnitude measurements, as well as both active and reactive power measurements for node injection and branch flow (measurement pairs as well as unpaired measurements). In addition, the SE solution requires information on scheduled desired voltages, forecasted load, and generation. The SE processes status measurements such as logical device positions, transformers, and phase shifter tap positions. In addition to these status measurements, dispatcher/operator entry of equipment status (open/close or different tap position) and data base default status information is utilized to build a complete real-time network model.

The result of the State Estimator function is a real-time network description with a complete steady-state complex voltage solution. This solved real-time network is created for the use of the several applications in the EMS including the Transmission Loss Calculation function.

6.0: Loss Calculations.

For the calculation of the demand losses, the monthly peak in NSP's LBA was used. The calculations for the demand losses are as follows:

2016 Demand Loss Calculations

	NSPM			NSPW		
Month	2016 Peak Demand (MW)	2016 Peak Loss (MW)	Percentage Loss	2016 Peak Demand (MW)	2016 Peak Loss (MW)	Percentage Loss
January	6,310	152.15	2.41%	1,298	48.23	3.72%
February	6,131	465.2	7.59%	1,221	135.68	11.11%
March	5,629	128.95	2.29%	1,110	66.71	6.01%
April	5,733	206.45	3.60%	1,025	79.99	7.81%
May	6,799	108.61	1.60%	1,120	23.14	2.07%
June	7,970	198.05	2.48%	1,293	48.83	3.78%
July	9,098	273.03	3.00%	1,485	82.62	5.56%
August	8,909	330.12	3.71%	1,484	91.18	6.14%
September	6,759	220.43	3.26%	1,241	82.43	6.64%
October	5,840	208.04	3.56%	1,047	55.98	5.35%
November	5,828	186.26	3.20%	1,088	56.83	5.22%
December	6,521	289.06	4.43%	1,282	62.46	4.87%
Total	81,528	2,766.35	**3.43%**	14,693	834.07	**5.69%**

2017 Demand Loss Calculations

	NSPM			NSPW		
Month	2017 Peak Demand (MW)	2017 Peak Loss (MW)	Percentage Loss	2017 Peak Demand (MW)	2017 Peak Loss (MW)	Percentage Loss
January	5,699	136.31	2.39%	1,246	55.94	4.49%
February	5,361	250.41	4.67%	1,218	71.40	5.86%
March	5,001	157.42	3.15%	1,138	62.99	5.54%
April	4,775	155.77	3.26%	1,053	55.49	5.27%
May	5,559	165.09	2.97%	1,080	58.49	5.42%
June	7,128	280.28	3.93%	1,287	76.75	5.96%
July	7,702	223.8	2.91%	1,428	63.41	4.44%
August	7,057	224.41	3.18%	1,344	83.43	6.21%
September	7,449	289.58	3.89%	1,379	83.13	6.03%
October	5,133	139.77	2.72%	1,134	56.67	5.00%
November	5,197	269.13	5.18%	1,192	54.61	4.58%
December	5,574	257.67	4.62%	1,269	89.65	7.06%
Total	71,635	2,549.64	**3.57%**	14,768	811.95	**5.49%**

2018 Demand Loss Calculations

	NSPM			NSPW		
Month	2018 Peak Demand (MW)	2018 Peak Loss (MW)	Percentage Loss	2018 Peak Demand (MW)	2018 Peak Loss (MW)	Percentage Loss
January	5,393	265.69	4.93%	1,312	84.08	6.41%
February	5,208	273.81	5.26%	1,227	70.80	5.77%
March	4,713	206.66	4.38%	1,147	41.40	3.61%
April	4,572	205.23	4.49%	1,114	41.13	3.69%
May	6,749	237.73	3.52%	1,457	67.23	4.61%
June	7,353	302.56	4.11%	1,494	58.84	3.94%
July	7,369	216.28	2.94%	1,453	38.96	2.68%
August	7,056	195.14	2.77%	1,437	81.41	5.67%
September	6,324	185.88	2.94%	1,298	49.59	3.82%
October	4,719	211.05	4.47%	1,043	42.08	4.03%
November	5,013	165.97	3.31%	1,196	39.15	3.27%
December	5,022	220.33	4.39%	1,236	51.11	4.14%
Total	69,491	2,686.33	**3.96%**	15,414	665.78	**4.30%**

2019 Demand Loss Calculations

Month	NSPM			NSPW		
	2019 Peak Demand (MW)	2019 Peak Loss (MW)	Percentage Loss	2019 Peak Demand (MW)	2019 Peak Loss (MW)	Percentage Loss
January	5,523	177.55	3.21%	1,308	40.38	3.09%
February	5,138	209.28	4.07%	1,246	33.05	2.65%
March	5,133	254.61	4.96%	1,261	54.04	4.28%
April	4,662	148.49	3.18%	1,055	42.65	4.04%
May	4,860	129.50	2.66%	1,101	31.90	2.90%
June	5,969	174.08	2.92%	1,201	33.65	2.80%
July	7,167	215.13	3.00%	1,452	57.16	3.94%
August	6,237	154.44	2.48%	1,292	55.15	4.27%
September	6,362	212.04	3.33%	1,206	38.20	3.17%
October	4,493	123.75	2.75%	1,067	31.03	2.91%
November	5,026	240.96	4.79%	1,218	86.76	7.12%
December	5,196	226.72	4.36%	1,256	66.47	5.29%
Total	65,766	2,266.55	**3.48%**	14,663	570.44	**3.87%**

Energy loss percentages were also calculated for the data collected for years 2016 through 2019.

2016 Energy Loss Calculations

Month	NSPM			NSPW		
	2016 Energy Demand (MWh)	2016 Energy Loss (MWh)	Percentage Loss	2016 Energy Demand (MWh)	2016 Energy Loss (MWh)	Percentage Loss
January	3,808,556	114,280	3.00%	761,192	27,713	3.64%
February	3,439,792	121,413	3.53%	689,509	28,767	4.17%
March	3,422,090	128,038	3.74%	665,909	31,751	4.77%
April	3,247,289	124,880	3.85%	619,747	31,963	5.16%
May	3,451,077	117,941	3.42%	641,956	23,959	3.73%
June	3,957,516	118,908	3.00%	690,700	24,785	3.59%
July	4,383,449	146,068	3.33%	772,843	31,601	4.09%
August	4,387,525	139,533	3.18%	781,824	31,872	4.08%
September	3,589,330	120,354	3.35%	664,740	27,135	4.08%
October	3,413,337	117,991	3.46%	647,228	27,190	4.20%
November	3,341,108	122,866	3.68%	640,656	30,283	4.73%
December	3,820,479	144,134	3.77%	744,789	32,502	4.36%
Total	44,261,548	1,516,406	**3.44%**	8,321,093	349,521	**4.22%**

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2017 Energy Loss Calculations

	NSPM			NSPW		
Month	2017 Energy Demand (MWh)	2017 Energy Loss (MWh)	Percentage Loss	2017 Energy Demand (MWh)	2017 Energy Loss (MWh)	Percentage Loss
January	3,378,577	129,461	3.83%	744,946	29,060	3.90%
February	2,880,055	121,734	4.23%	647,470	29,012	4.48%
March	3,118,766	114,781	3.68%	693,992	30,038	4.33%
April	2,820,330	106,629	3.78%	616,683	25,296	4.10%
May	2,976,340	102,629	3.45%	638,274	27,187	4.26%
June	3,428,793	122,934	3.59%	697,040	27,208	3.90%
July	3,840,430	131,212	3.42%	770,864	29,957	3.89%
August	3,442,515	144,925	4.21%	721,408	32,764	4.54%
September	3,279,553	108,568	3.31%	687,254	28,327	4.12%
October	3,028,929	111,112	3.67%	676,056	26,157	3.87%
November	3,031,111	116,967	3.86%	704,569	26,565	3.77%
December	3,315,761	135,446	4.08%	772,858	35,988	4.66%
Total	38,541,160	1,446,398	**3.76%**	8,371,414	347,558	**4.15%**

2018 Energy Loss Calculations

	NSPM			NSPW		
Month	2018 Energy Demand (MWh)	2018 Energy Loss (MWh)	Percentage Loss	2018 Energy Demand (MWh)	2018 Energy Loss (MWh)	Percentage Loss
January	3,220,112	153,722	4.77%	797,619	50,950	6.39%
February	2,866,683	133,109	4.64%	693,301	39,713	5.73%
March	2,880,232	117,571	4.08%	702,771	44,049	6.27%
April	2,734,315	114,236	4.18%	660,913	35,375	5.35%
May	3,060,320	105,278	3.44%	700,652	37,980	5.42%
June	3,317,870	111,562	3.36%	727,380	35,762	4.92%
July	3,567,768	116,162	3.26%	778,399	41,522	5.33%
August	3,507,871	113,671	3.24%	771,605	37,628	4.88%
September	2,971,664	105,269	3.54%	666,165	35,299	5.30%
October	2,779,699	103,902	3.74%	665,120	29,062	4.37%
November	2,885,219	110,197	3.82%	700,895	32,645	4.66%
December	3,034,659	122,027	4.02%	733,213	38,509	5.25%
Total	36,826,410	1,406,706	**3.84%**	8,598,033	458,495	**5.32%**

2019 Energy Loss Calculations

Month	NSPM			NSPW		
	2019 Energy Demand (MWh)	2019 Energy Loss (MWh)	Percentage Loss	2019 Energy Demand (MWh)	2019 Energy Loss (MWh)	Percentage Loss
January	3,170,350	122,819	3.87%	781,544	35,800	4.58%
February	2,920,764	116,863	4.00%	708,121	28,944	4.09%
March	2,902,710	109,504	3.77%	721,223	36,109	5.01%
April	2,632,077	92,612	3.52%	632,666	27,147	4.29%
May	3,060,320	93,907	3.07%	696,204	30,255	4.35%
June	3,317,870	100,530	3.03%	718,438	36,073	5.02%
July	3,567,768	115,939	3.25%	777,766	45,346	5.83%
August	3,507,871	111,063	3.17%	766,023	45,601	5.95%
September	2,971,664	112,846	3.80%	668,411	45,560	6.82%
October	2,779,699	106,021	3.81%	659,011	34,365	5.21%
November	2,885,219	116,690	4.04%	699,151	46,679	6.68%
December	3,034,659	106,678	3.52%	734,397	40,649	5.54%
Total	36,750,970	1,305,471	**3.57%**	8,562,954	452,527	**5.28%**

With the numbers calculated in this study, a 48 month average was calculated to provide recommended loss factors for the Interchange Agreement. These recommended loss factors are shown in the table below.

2019 NSP Loss Study Ratios (proposed loss factors)		
Loss Ratios	NSPM	NSPW
Demand	3.61%	4.84%
Energy	3.65%	4.74%

7.0: Validation of Energy Management System (EMS) Losses.

Validation was performed on NSP's state estimator data, which is sourced from NSP's Energy Management System (EMS), to ensure accurate results for this loss study. Two forms of validation were performed with a criterion that results should be within 5 percent. The first validation was to compare NSP's state estimator data with an independent set of data. In this case, the MISO state estimator loss data was chosen. One detail to note is that the MISO state estimator only monitors facilities under MISO functional control. The facilities under MISO functional control are 100 kV and above. This means, in order to compare the two state estimator results, NSP's data needs to be restricted to assets that are 100 kV and above. The second validation will be to perform offline calculation in PSS/e for the sub-100 kV assets.

Validation of NSP EMS Losses vs. MISO State Estimator Losses

The NSP state estimator results were compared to the MISO state estimator results for validation purposes. Peak hour data from August 26, 2013 at 5 p.m. was used for this comparison and validation. MISO's state estimator calculated NSP Local Balancing Authority (LBA) losses at 265 MW. NSP's state estimator calculated a total of 261.97 MW for the 100 kV and above assets. The two state estimator calculations differ by 1.5 percent, which is an acceptable variance for validation.

Validation of NSP EMS Losses vs. PSS/e Offline Powerflow Calculations

To validate the state estimator losses for assets that are below 100 kV, an offline comparison was performed using the same August 26th peak hour data. A PSS/e powerflow model was setup to recreate the flows observed on the state estimator on the August 26, 2013 peak hour. The flow is recreated by a two bus system in which the observed flow is recreated by a negative load with a swing bus to calculate the losses. The swing bus would also regulate the voltage on the load bus to 1 per unit (pu). The impedance for the 69 kV lines was obtained from NSP's CAPE models, which contain the most accurate data for line impedances for NSP transmission lines.

The first transmission line selected for verification is the Cannon Falls – Northfield 69 kV transmission line. The impedance parameters provided by NSP's CAPE model for this line are:

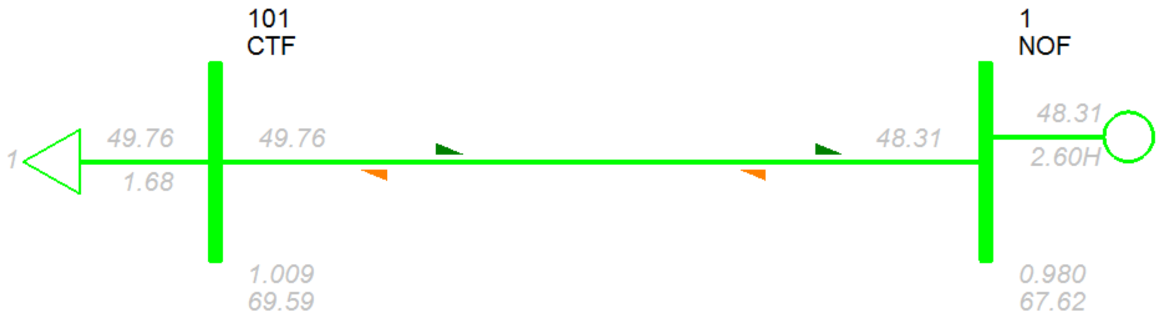
R = .05956 pu, X = .19297 pu, B = .00417 pu

The state estimator data for this line is as follows:

Company	Division	Sub Station	Name	Type	Volt	Src Rpt Date	Src Rpt Hr	Mw	Mvar	Loss
NSP	KEYSTN	CTF	CTF-NOF	LINE	69	8/26/2013	17:13	49.76	1.68	1.44

A PSS/e model was created in PSS/e version 33.6 to recreate the flows observed in the state estimator. The real power flow condition of 49.76 MW leaving the Cannon Falls

Transmission substation was recreated by a negative load and a swing bus being placed at Northfield bus to solve for the loss on the Cannon Falls Transmission – Northfield 69 kV line. Upon solving this simple model, PSS/e calculated a loss value of 1.45 MW, which is slightly higher than the 1.44 MW calculated by the state estimator. However, this difference is less than 1 percent, which validates the state estimator results.

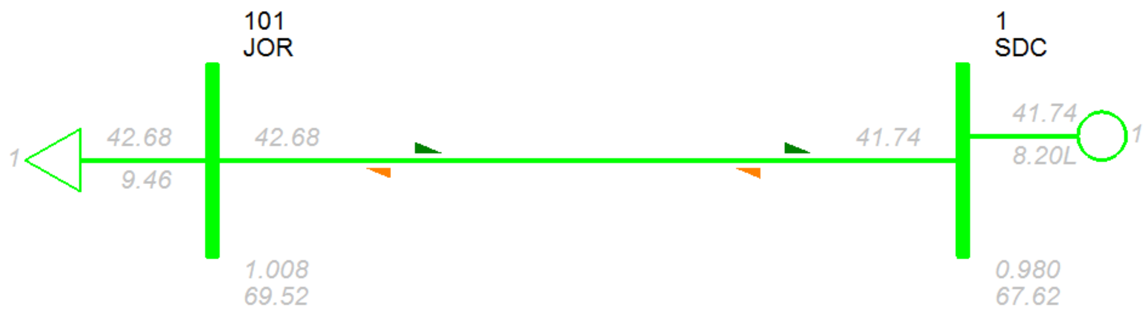


The Jordan to Sand Creek 69 kV transmission line was also selected as a line to validate the NSP companies state estimator results. The impedance parameters provided by NSP's CAPE model for this line are:

R = .04969 pu, X = .07283 pu, B = .00114 pu

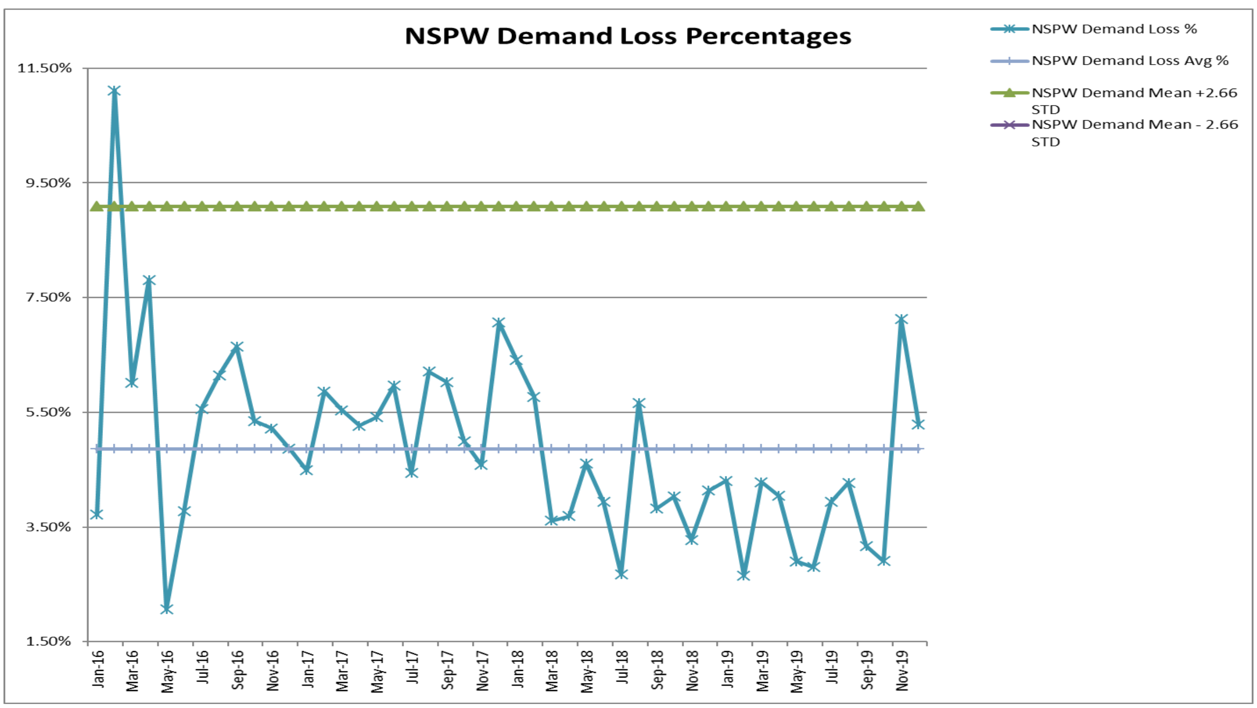
Company	Division	Sub Station	Name	Type	Volt	Src Rpt Date	Src Rpt Hr	Mw	Mvar	Loss
NSP	KEYSTN	JOR	JOR-SDC	LINE	69	8/26/13	17:13	42.68	9.46	0.93

Again, a PSS/e model was created in PSS/e version 33.6 to recreate the actual flows observed in the state estimator. The real power flow was 42.68 MW leaving the Jordan substation and was recreated by a negative load and a swing bus was placed at Sand Creek bus to solve for the losses on the Jordan-Sand Creek 69 kV line. Upon solving this PSS/e model, PSS/e calculated a loss of 0.94 MW, which is slightly higher than the 0.93 MW calculated by the state estimator. This difference is approximately 1 percent, which validates the state estimator results.



Validation of NSP EMS Losses statistical outlier analysis

A final validation was performed to identify any outlier percentages for the percentages that were calculated. The standard deviations were calculated for the four loss percentages in this report and multiplied by 2.66. This number was added and subtracted to the mean percentage and plotted in the graphs below. Any percentage outside of these bounds should only have less than a 1 percent probability and should be investigated further.



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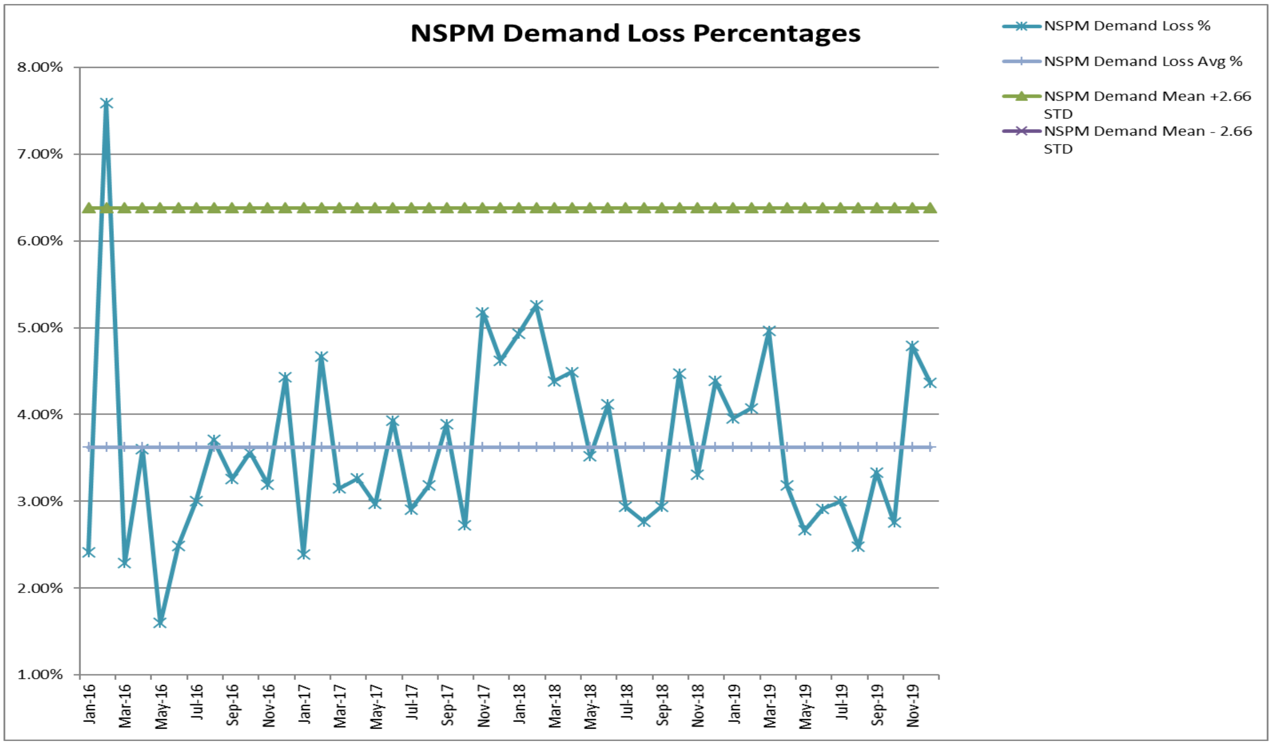

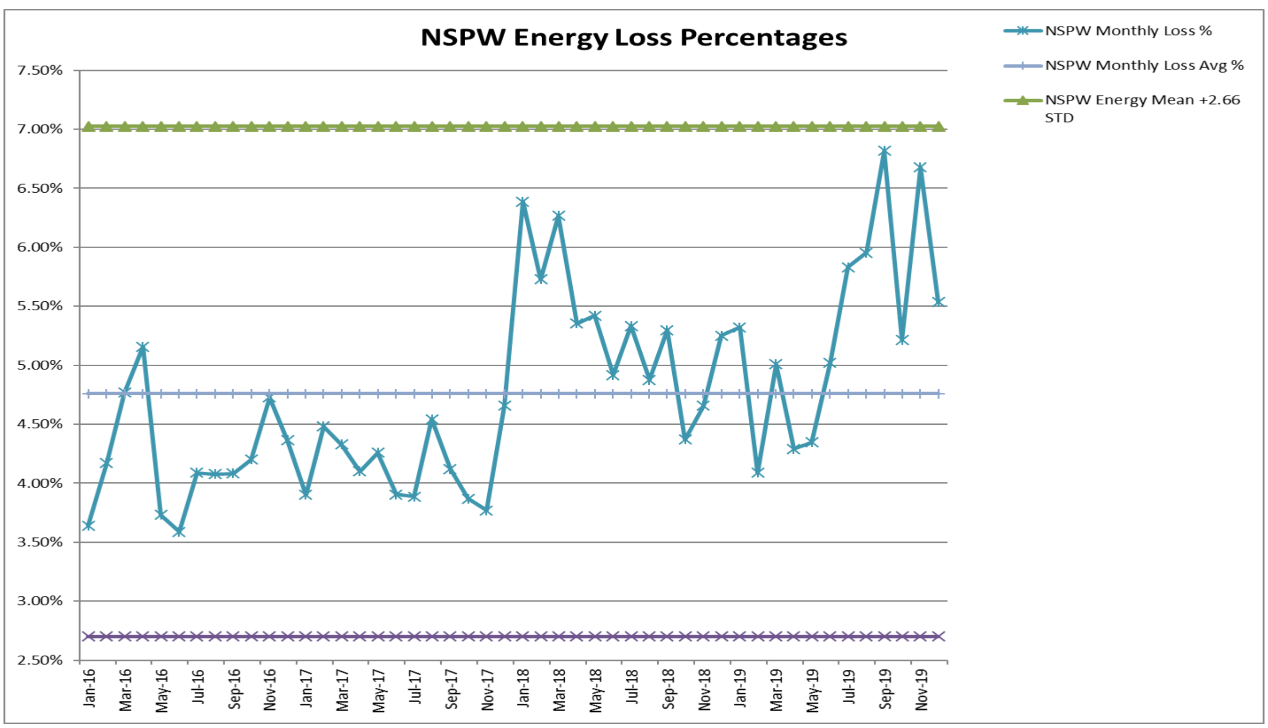

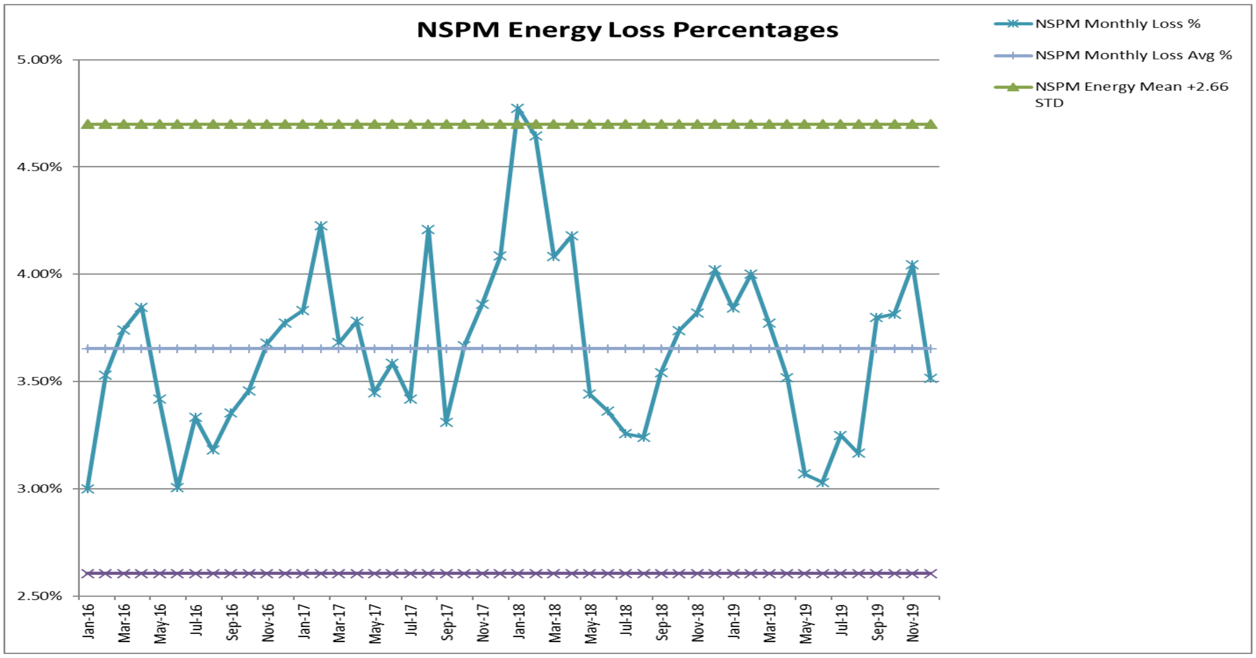

February 8, 2016 data point, NSPM and NSPW demand loss percentage data was outside of 2.66 standard deviations from the mean. That day was a high transfer day leading to high losses on the 500 kV system and interconnected 230kV system in northern Minnesota and high transfers into Wisconsin from Minnesota.

January 2018, NSPM energy loss percentage data was outside of 2.66 standard deviations from the mean. That month was during the polar vortex, in which temperatures dropped to very low levels resulting in many generators not being able to operate. Many of the generators that were able to run were located in Minnesota and were exporting to other regions, leading to increased losses.

Exhibits

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

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.~~963~~964 for NSP(Minn)
0.952 for NSP(Wis)

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY 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 current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~964~~963 for NSP(Minn)
0.~~951~~953 for NSP(Wis)

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

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR 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.~~963~~964 for NSP(Minn)
0.952 for NSP(Wis)

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY 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 current month excluding energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~964~~963 for NSP(Minn)
0.~~951~~953 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

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)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		

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)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
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)

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 1**

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 and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1.1

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 Midcontinent Independent System Operator, Inc.'s (MISO) 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.2

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2

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 intangible, 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2.1

ACCUMULATED PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 3

ACCUMULATED DEFERRED INCOME TAXES

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

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.1

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 Midcontinent Independent 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 4.2**

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
Functional Class	**Total NSP (Minn) Actual to Theoretical Reserve Difference**	**NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference**	**NSP (Wis) Actual to Theoretical Reserve Difference**
Intangible 1/	$417,044	$365,054	$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).
2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 5

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 6

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 6 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 6

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, or such date after January 1 determined by the Coordinating Committee, 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 such 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 of 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

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

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

Agreement to Coordinate Planning and Operations and Interchange Power and Energy — **Exhibit V Schedule 7**

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 8.1**

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 8.2**

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.3

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT
RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.4

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC (“Benson Power”) biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the “Total Actual Benson Power Termination Costs”). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)’s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility (“Benson Power Termination Costs”).

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)’s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)’s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)’s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 9

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 10

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 11

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 12

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12.1

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 13

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 14

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 15

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 16

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 17**

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

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

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)		

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit VI
Schedule 2**

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2.1

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. 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. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Windsource® program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price (“LMP”) from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

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

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 10.40%.

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2021 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2019	January	5,523	1,156	6,679
	February	5,138	1,082	6,220
	March	5,133	1,097	6,231
	April	4,679	936	5,615
	May	5,167	989	6,156
	June	6,388	1,065	7,454
	July	7,469	1,305	8,774
	August	6,539	1,209	7,748
	September	6,619	1,093	7,712
	October	4,535	938	5,473
	November	5,026	1,064	6,090
	December	5,196	1,097	6,293
	Total	67,413	13,032	80,445
2020	January	5,093	1,077	6,170
	February	4,996	1,094	6.090
	March	4,593	949	5,542
	April	4,244	852	5,096
	May	5,120	986	6,106
	June	6,925	1,191	8,116
	July	6,687	1,237	7,924
	August	6,648	1,276	7,924
	September	5,992	1,093	7,085
	October	4,339	900	5,239
	November	4,418	950	5,368
	December	4,845	1,061	5,906
	Total	63,900	12,666	76,566
2021	January	4,867	1,057	5,924
	February	4,701	1,017	5,718
	March	4,543	962	5,505
	April	4,151	875	5,026
	May	5,222	1,015	6,237
	June	6,810	1,254	8,064
	July	6,812	1,263	8,076
	August	6,771	1,305	8,076
	September	6,126	1,121	7,247
	October	4,469	931	5,400
	November	4,554	981	5,537
	December	4,982	1,095	6,077
	Total	64,008	12,879	76,887

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2021 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. 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
PRODUCTION			
E311	STEAM	Structures and Improvements	4.38%
E312	STEAM	Boiler Plant Equipment	4.47%
E314	STEAM	Turbogenerator Units	4.66%
E315	STEAM	Accessory Electric Equipment	3.65%
E316	STEAM	Miscellaneous Power Plant Equipment	3.94%
E302	NUCLEAR	Franchises & Consents	5.23%
E321	NUCLEAR	Structures and Improvements	5.01%
E322	NUCLEAR	Reactor Plant Equipment	4.01%
E323	NUCLEAR	Turbogenerator Units	3.58%
E324	NUCLEAR	Accessory Electric Equipment	4.09%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.83%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	7.57%
E332	HYDRO	Reservoirs, Dams and Waterways	5.28%
E333	HYDRO	Water Wheels, Turbines & Generators	5.49%
E334	HYDRO	Accessory Electric Equipment	5.86%
E335	HYDRO	Miscellaneous Power Plant Equipment	9.09%
E340.1	OTHER	Wind Rights	4.31%
E341	OTHER	Structures and Improvements	3.79%
E342	OTHER	Fuel Holders, Producers & Accessories	4.23%
E343	OTHER	Prime Movers	3.32%
E344	OTHER	Generators	4.09%
E345	OTHER	Accessory Electric Equipment	3.84%
E346	OTHER	Miscellaneous Power Plant Equipment	6.21%
E348	OTHER	Energy Storage Equipment – Production	7.15%

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

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.48%
*E352	Structures and Improvements-Prod.	1.48%
E353	Station Equipment	2.03%
*E353	Station Equipment-Prod.	2.03%
E354	Towers and Fixtures	1.78%
*E354	Towers and Fixtures-Prod.	1.78%
E355	Poles and Fixtures	2.39%
*E355	Poles and Fixtures-Prod.	2.39%
E356	Overhead Conductors & Devices	2.02%
*E356	Overhead Conductors & Devices-Prod.	2.02%
E357	Underground Conduit	1.36%
E358	Underground Conductors & Devices	2.05%
DISTRIBUTION		
E361	Structures and Improvements	2.09%
*E361	Structures and Improvements-Prod.	2.08%
E362	Station Equipment	2.29%
*E362	Station Equipment-Prod.	2.31%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	4.64%
E365	Overhead Conductors and Devices	3.18%
E366	Underground Conduit	2.14%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	3.21%
E368	Line Capacitors	3.97%
E369	Overhead Services	4.34%
E369	Underground Services	2.41%
E370	Meters	5.67%
E370.2	AGIS Meters	5.58%
E370.3	Electric Vehicle Chargers	5.58%
E373	Street Lighting and Signal Systems	5.27%

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

GENERAL - ELECTRIC

E302	Franchises & Consents	5.50%
E303	Intangible Plant – 5 Year	20.77%
E303	Intangible Plant – 10 Year	10.00%
E390	Structures and Improvements	2.23%
E391	Office Furniture and Equipment	4.70%
E391	Network Equipment	16.28%
E392	Transportation Equipment – Auto	9.77%
E392	Transportation Equipment – Light Truck	8.65%
E392	Transportation Equipment – Trailers	6.41%
E392	Transportation Equipment – Heavy Trucks	6.73%
E393	Stores Equipment	4.54%
E394	Tools, Shop and Garage Equipment	6.39%
E395	Laboratory Equipment	9.84%
E396	Power Operated Equipment	6.09%
E397	Communication Equipment – General	9.61%
E397	Communication Equipment – Two Way	10.18%
E397	Communication Equipment – AMR	6.08%
*E397	Communication Equipment – EMS	6.30%
E397	Communication Equipment – Smart Grid	9.61%
E398	Miscellaneous Equipment	6.31%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2021 Approved Accrual	Docket No./Case No.
Minnesota Retail	$14,030,831	E-002/M-17-828
North Dakota Retail	$276,513	PU-12-813
South Dakota Retail	$1,234,251	EL14-058
Wisconsin Retail	$4,830,150	4220-UR-124

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2021 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	6.06%
E312	STEAM	Boiler Plant Equipment	4.77%
E314	STEAM	Turbogenerator Units	4.80%
E315	STEAM	Accessory Electric Equipment	5.70%
E316	STEAM	Miscellaneous Power Plant Equipment	3.95%
E302	HYDRO	Franchises & Consents	3.85%
E331	HYDRO	Structures and Improvements	3.68%
E332	HYDRO	Reservoirs, Dams and Waterways	3.75%
E333	HYDRO	Water Wheels, Turbines & Generators	4.24%
E334	HYDRO	Accessory Electric Equipment	4.71%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.28%
E341	OTHER	Structures and Improvements	2.50%
E342	OTHER	Fuel Holders, Producers & Accessories	3.04%
E343	OTHER	Prime Movers	3.66%
E344	OTHER	Generators	3.09%
E345	OTHER	Accessory Electric Equipment	3.20%
E346	OTHER	Miscellaneous Power Plant Equipment	1.71%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.01%
*E352		Structures and Improvements-Prod.	1.98%
E353		Station Equipment	2.58%
*E353		Station Equipment-Prod.	2.33%
E354		Towers and Fixtures	1.73%
E355		Poles and Fixtures	2.99%
E356		Overhead Conductors & Devices	2.60%
E357		Underground Conduit	2.08%
E358		Underground Conductors & Devices	2.73%
E359		Roads and Trails	1.43%

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

DISTRIBUTION		
E361	Structures and Improvements	2.13%
*E361	Structures and Improvements – Prod.	2.12%
E362	Station Equipment	2.44%
*362	Station Equipment – Prod.	2.41%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	5.48%
E365	Overhead Conductors and Devices	4.28%
E366	Underground Conduit	1.80%
E367	Underground Conductor and Devices	2.73%
E368	Line Transformers	2.56%
E368	Line Capacitors	3.09%
E369	Overhead Services	4.02%
E369	Underground Services	2.78%
E370	Meters	3.99%
E370.1	Meters – Old	4.90%
E370.2	Meters – AMR	6.53%
E371	Customer Installations	5.36%
E373	Street Lighting and Signal Systems	6.63%

GENERAL ELECTRIC		
E302	Franchises & Consents	5.00%
E303	Intangible Plant – 5 Year	21.13%
E303	Intangible Plant – 7 Year	14.29%
E390	Structures and Improvements	2.59%
E391	Office Furniture and Equipment	4.97%
E391	Network Equipment	24.25%
E392	Transporation Equipment – Auto	13.51%
E392	Transportation Equipment – Light Truck	9.81%
E392	Transportation Equipment – Trailers	9.97%
E392	Transportation Equipment – Heavy Truck	9.96%
E393	Stores Equipment	4.97%
E394	Tools, Shop and Garage Equipment	4.97%
E395	Laboratory Equipment	4.75%
E396	Power Operated Equipment	8.23%
E397	Communication Equipment – AES/AMR	6.63%
*E397	Communication Equipment – EMS	9.05%
E398	Miscellaneous Equipment	4.98%

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

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	

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

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification 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	
548.1	Operation of energy storage equipment	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	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

Exhibits

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

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:

0.964 for NSP(Minn)
0.952 for NSP(Wis)

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY 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 current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.963 for NSP(Minn)
0.953 for NSP(Wis)

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

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR 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:

0.964 for NSP(Minn)
0.952 for NSP(Wis)

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY 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 current month excluding energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.963 for NSP(Minn)
0.953 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Windsource® program.

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

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)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		

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)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
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)

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1

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 and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.1

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 Midcontinent Independent System Operator, Inc.'s (MISO) 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.2

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 2**

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 intangible, 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2.1

ACCUMULATED PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 3**

ACCUMULATED DEFERRED INCOME TAXES

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

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.1

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 Midcontinent Independent 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 4.2**

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
Functional Class	**Total NSP (Minn) Actual to Theoretical Reserve Difference**	**NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference**	**NSP (Wis) Actual to Theoretical Reserve Difference**
Intangible 1/	$417,044	$365,054	$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).
2/ Distribution reserve difference included under "NSP (Wis) Actual to Theoretical Reserve Difference" relates to Distribution serving system generation.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 5**

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy | **Exhibit V Schedule 6**

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 6 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, or such date after January 1 determined by the Coordinating Committee, 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 such 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 of 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 8.2**

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 8.3**

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT
RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.4

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 9

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 10

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 11

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12.1

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market 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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 13

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 14

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 15

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 16

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 17

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

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

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)		

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 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.

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Exhibit VI Schedule 2

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.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2.1

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.

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Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. 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. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies or statutes that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Windsource® program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price (“LMP”) from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

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

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 10.40%.

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2021 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2019	January	5,523	1,156	6,679
	February	5,138	1,082	6,220
	March	5,133	1,097	6,231
	April	4,679	936	5,615
	May	5,167	989	6,156
	June	6,388	1,065	7,454
	July	7,469	1,305	8,774
	August	6,539	1,209	7,748
	September	6,619	1,093	7,712
	October	4,535	938	5,473
	November	5,026	1,064	6,090
	December	5,196	1,097	6,293
	Total	67,413	13,032	80,445
2020	January	5,093	1,077	6,170
	February	4,996	1,094	6.090
	March	4,593	949	5,542
	April	4,244	852	5,096
	May	5,120	986	6,106
	June	6,925	1,191	8,116
	July	6,687	1,237	7,924
	August	6,648	1,276	7,924
	September	5,992	1,093	7,085
	October	4,339	900	5,239
	November	4,418	950	5,368
	December	4,845	1,061	5,906
	Total	63,900	12,666	76,566
2021	January	4,867	1,057	5,924
	February	4,701	1,017	5,718
	March	4,543	962	5,505
	April	4,151	875	5,026
	May	5,222	1,015	6,237
	June	6,810	1,254	8,064
	July	6,812	1,263	8,076
	August	6,771	1,305	8,076
	September	6,126	1,121	7,247
	October	4,469	931	5,400
	November	4,554	981	5,537
	December	4,982	1,095	6,077
	Total	64,008	12,879	76,887

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2021 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. 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
PRODUCTION			
E311	STEAM	Structures and Improvements	4.38%
E312	STEAM	Boiler Plant Equipment	4.47%
E314	STEAM	Turbogenerator Units	4.66%
E315	STEAM	Accessory Electric Equipment	3.65%
E316	STEAM	Miscellaneous Power Plant Equipment	3.94%
E302	NUCLEAR	Franchises & Consents	5.23%
E321	NUCLEAR	Structures and Improvements	5.01%
E322	NUCLEAR	Reactor Plant Equipment	4.01%
E323	NUCLEAR	Turbogenerator Units	3.58%
E324	NUCLEAR	Accessory Electric Equipment	4.09%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.83%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	7.57%
E332	HYDRO	Reservoirs, Dams and Waterways	5.28%
E333	HYDRO	Water Wheels, Turbines & Generators	5.49%
E334	HYDRO	Accessory Electric Equipment	5.86%
E335	HYDRO	Miscellaneous Power Plant Equipment	9.09%
E340.1	OTHER	Wind Rights	4.31%
E341	OTHER	Structures and Improvements	3.79%
E342	OTHER	Fuel Holders, Producers & Accessories	4.23%
E343	OTHER	Prime Movers	3.32%
E344	OTHER	Generators	4.09%
E345	OTHER	Accessory Electric Equipment	3.84%
E346	OTHER	Miscellaneous Power Plant Equipment	6.21%
E348	OTHER	Energy Storage Equipment – Production	7.15%

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

<u>TRANSMISSION</u>		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.48%
*E352	Structures and Improvements-Prod.	1.48%
E353	Station Equipment	2.03%
*E353	Station Equipment-Prod.	2.03%
E354	Towers and Fixtures	1.78%
*E354	Towers and Fixtures-Prod.	1.78%
E355	Poles and Fixtures	2.39%
*E355	Poles and Fixtures-Prod.	2.39%
E356	Overhead Conductors & Devices	2.02%
*E356	Overhead Conductors & Devices-Prod.	2.02%
E357	Underground Conduit	1.36%
E358	Underground Conductors & Devices	2.05%
<u>DISTRIBUTION</u>		
E361	Structures and Improvements	2.09%
*E361	Structures and Improvements-Prod.	2.08%
E362	Station Equipment	2.29%
*E362	Station Equipment-Prod.	2.31%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	4.64%
E365	Overhead Conductors and Devices	3.18%
E366	Underground Conduit	2.14%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	3.21%
E368	Line Capacitors	3.97%
E369	Overhead Services	4.34%
E369	Underground Services	2.41%
E370	Meters	5.67%
E370.2	AGIS Meters	5.58%
E370.3	Electric Vehicle Chargers	5.58%
E373	Street Lighting and Signal Systems	5.27%

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GENERAL - ELECTRIC

E302	Franchises & Consents	5.50%
E303	Intangible Plant – 5 Year	20.77%
E303	Intangible Plant – 10 Year	10.00%
E390	Structures and Improvements	2.23%
E391	Office Furniture and Equipment	4.70%
E391	Network Equipment	16.28%
E392	Transportation Equipment – Auto	9.77%
E392	Transportation Equipment – Light Truck	8.65%
E392	Transportation Equipment – Trailers	6.41%
E392	Transportation Equipment – Heavy Trucks	6.73%
E393	Stores Equipment	4.54%
E394	Tools, Shop and Garage Equipment	6.39%
E395	Laboratory Equipment	9.84%
E396	Power Operated Equipment	6.09%
E397	Communication Equipment – General	9.61%
E397	Communication Equipment – Two Way	10.18%
E397	Communication Equipment – AMR	6.08%
*E397	Communication Equipment – EMS	6.30%
E397	Communication Equipment – Smart Grid	9.61%
E398	Miscellaneous Equipment	6.31%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2021 Approved Accrual	Docket No./Case No.
Minnesota Retail	$14,030,831	E-002/M-17-828
North Dakota Retail	$276,513	PU-12-813
South Dakota Retail	$1,234,251	EL14-058
Wisconsin Retail	$4,830,150	4220-UR-124

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SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2021 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	6.06%
E312	STEAM	Boiler Plant Equipment	4.77%
E314	STEAM	Turbogenerator Units	4.80%
E315	STEAM	Accessory Electric Equipment	5.70%
E316	STEAM	Miscellaneous Power Plant Equipment	3.95%
E302	HYDRO	Franchises & Consents	3.85%
E331	HYDRO	Structures and Improvements	3.68%
E332	HYDRO	Reservoirs, Dams and Waterways	3.75%
E333	HYDRO	Water Wheels, Turbines & Generators	4.24%
E334	HYDRO	Accessory Electric Equipment	4.71%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.28%
E341	OTHER	Structures and Improvements	2.50%
E342	OTHER	Fuel Holders, Producers & Accessories	3.04%
E343	OTHER	Prime Movers	3.66%
E344	OTHER	Generators	3.09%
E345	OTHER	Accessory Electric Equipment	3.20%
E346	OTHER	Miscellaneous Power Plant Equipment	1.71%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.01%
*E352		Structures and Improvements-Prod.	1.98%
E353		Station Equipment	2.58%
*E353		Station Equipment-Prod.	2.33%
E354		Towers and Fixtures	1.73%
E355		Poles and Fixtures	2.99%
E356		Overhead Conductors & Devices	2.60%
E357		Underground Conduit	2.08%
E358		Underground Conductors & Devices	2.73%
E359		Roads and Trails	1.43%

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<u>DISTRIBUTION</u>		
E361	Structures and Improvements	2.13%
*E361	Structures and Improvements – Prod.	2.12%
E362	Station Equipment	2.44%
*362	Station Equipment – Prod.	2.41%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	5.48%
E365	Overhead Conductors and Devices	4.28%
E366	Underground Conduit	1.80%
E367	Underground Conductor and Devices	2.73%
E368	Line Transformers	2.56%
E368	Line Capacitors	3.09%
E369	Overhead Services	4.02%
E369	Underground Services	2.78%
E370	Meters	3.99%
E370.1	Meters – Old	4.90%
E370.2	Meters – AMR	6.53%
E371	Customer Installations	5.36%
E373	Street Lighting and Signal Systems	6.63%
<u>GENERAL ELECTRIC</u>		
E302	Franchises & Consents	5.00%
E303	Intangible Plant – 5 Year	21.13%
E303	Intangible Plant – 7 Year	14.29%
E390	Structures and Improvements	2.59%
E391	Office Furniture and Equipment	4.97%
E391	Network Equipment	24.25%
E392	Transporation Equipment – Auto	13.51%
E392	Transportation Equipment – Light Truck	9.81%
E392	Transportation Equipment – Trailers	9.97%
E392	Transportation Equipment – Heavy Truck	9.96%
E393	Stores Equipment	4.97%
E394	Tools, Shop and Garage Equipment	4.97%
E395	Laboratory Equipment	4.75%
E396	Power Operated Equipment	8.23%
E397	Communication Equipment – AES/AMR	6.63%
*E397	Communication Equipment – EMS	9.05%
E398	Miscellaneous Equipment	4.98%

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

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	

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

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification 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	
548.1	Operation of energy storage equipment	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	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed