Exhibits Version: 0.4.2 Effective: 1/1/2014

Exhibits

Exhibit I	-	Formula-type Procedures for Development of Amounts of Power Sales
Exhibit II	-	Formula-type Procedures for Development of Amounts of Energy Sales
Exhibit III	-	Formula-type Procedures for Development of Unit Rates for Power Sales
Exhibit IV	-	Formula-type Procedures for Development of Unit Rates for Energy Sales
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FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

"Transmission Loss Multipliers" are equal to:

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

"Transmission Loss Multipliers" are equal to:

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

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

"Transmission Loss Multipliers" are equal to:

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

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

"Transmission Loss Multipliers" are equal to:

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	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)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

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

C. Fixed Transmission Expense

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

ELECTRIC PLANT IN SERVICE

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

1. Intangible Plant Investment
   Water power 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 through348.

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

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

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

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

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the 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.

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.

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.

PLANT HELD FOR FUTURE USE - LAND

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

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the 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.

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 to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) over a period other than the average remaining life. In the 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC ordered NSP (Minn) to amortize the theoretical reserve surplus for transmission, distribution, intangible, and general assets over an eight-year period, commencing January 1, 2013. The NSP (Wis) portion of the reserve is $26,674,271. The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

In its 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868), NSP (Minn) proposed to accelerate the amortization of the theoretical reserve surplus. Specifically, NSP (Minn) proposed that 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. In its order setting interim rates issued January 2, 2014, the MPUC approved the Company's interim rates proposal, subject to refund and hearing procedures. A final MPUC decision is expected in March 2015.

This account is classified to the transmission, distribution, intangible and general functions of plant.

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	NSP (Wis) Actual to Theoretical Reserve Difference (Remaining Balance as of Jan. 1, 2014)
Intangible 1/	$417,044	$365,054	$0	$0
Transmission	200,466,880	149,597,398	26,645,321	23,314,656
Distribution 2/	109,362,353	109,362,353	18,051	15,795
General	6,727,378	5,888,716	10,899	9,536
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271	$23,339,987

If the final MPUC order in the 2014 test year rate case approves an amortization of the theoretical depreciation reserve different from that approved for interim rates, NSP (Minn) proposes to true-up the impact in 2015.

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.

<u>OTHER</u>

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

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

RETURN ON RATE BASE

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

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

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

Equity Return:

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

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

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

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

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

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

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

8. Income Tax Base

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

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

12. Federal and State Income Taxes

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

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

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

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

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:

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

Only North Dakota and Federal Income Taxes:

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

Only South Dakota and Federal Income Taxes:

S + F = _______________ (N)

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

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

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes

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

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

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

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

Income Tax Depreciation

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

Interest Expense

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

Preferred Dividend Credit

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

DEPRECIATION AND AMORTIZATION EXPENSE

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

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

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 for purposes of amortizing the NSP (Wis) portion ($26,674,271) of the NSP (Minn) theoretical reserve surplus amortization, as calculated on Exhibit V, Schedule 4.2. These amounts are in accordance with the Minnesota Public Utilities Commission (MPUC) decisions listed in Exhibit V, Schedule 4.2. The September 3, 2013 MPUC order in the 2013 NSP (Minn) test year rate case (Docket No. E002/GR-12-961) included an 8 year amortization period beginning January 1, 2013. The January 2, 2014 MPUC order setting interim rates in the 2014 NSP (Minn) test year rate case (Docket No. E002/GR-13-868) accepted the first year of NSP (Minn)'s proposal to amortize 50 percent of the remaining theoretical reserve surplus in 2014, subject to refund and hearing procedures. A final MPUC decision is expected in March 2015.

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)

Theoretical Reserve Surplus Amortization Expense represents the current year amortization of the total theoretical depreciation reserve surplus over the amortization period determined by the MPUC. If the final MPUC order in the 2014 test year rate case approves an amortization of the theoretical depreciation reserve different from that approved for interim rates, NSP (Minn) proposes to true-up the impact in 2015.

Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset)[1], by the plant functional classifications.

[1] When the amortization is completed, NSP (Minn) and NSP (Wis) will make a section 205 filing with the Commission to add FERC Account 407.3 (reduction of Regulatory Asset), or other appropriate account, to this Schedule 8.1, to amortize the Theoretical Reserve Surplus regulatory asset over the average remaining lives of the functional classes of assets.

PROVISION FOR DEFERRED INCOME TAXES

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

PROPERTY TAXES

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

INSURANCE EXPENSE

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

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

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

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

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.

NET PURCHASED POWER DEMAND COSTS

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

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

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

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

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

CREDITS FOR PRODUCTION-RELATED SERVICES

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

CREDITS FOR TRANSMISSION RELATED SERVICES

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

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

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

FUEL EXPENSES

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

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

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

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

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

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power 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.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

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

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

		Calendar Year 2014 Contract Year Monthly Coincidental Peak Demands (KW)		
		NSP (Minn)	NSP (Wis)	Total System
2012	January	5371	1031	6402
	February	4967	966	5933
	March	5020	921	5941
	April	4710	879	5590
	May	6067	948	7015
	June	7409	1149	8558
	July	8049	1337	9386
	August	7433	1228	8661
	September	7005	1220	8225
	October	4914	963	5877
	November	5210	1007	6216
	December	5382	1027	6409
	Total	71,536	12,675	84,211
2013	January	5559	1112	6671
	February	5316	1030	6346
	March	5012	978	5990
	April	4762	894	5656
	May	5433	845	6278
	June	6898	1111	8009
	July	7303	1302	8605
	August	7353	1252	8605
	September	6670	1186	7856
	October	5151	916	6067
	November	5342	1007	6350
	December	5462	1064	6526
	Total	70,262	12,698	82,961
2014	January	5662	1078	6740
	February	5536	1064	6600
	March	5108	1015	6123
	April	4920	949	5869
	May	5871	1039	6910
	June	7400	1263	8663
	July	7335	1327	8662
	August	7384	1277	8661
	September	6705	1215	7920
	October	5183	937	6120
	November	5389	1037	6426
	December	5511	1090	6601
	Total	72,003	13,292	85,295

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2014 CONTRACT YEAR

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

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	4.75%
E312	STEAM	Boiler Plant Equipment	3.48%
E314	STEAM	Turbogenerator Units	3.53%
E315	STEAM	Accessory Electric Equipment	3.08%
E316	STEAM	Miscellaneous Power Plant Equipment	3.68%
E302	NUCLEAR	Franchises & Consents	4.49%
E321	NUCLEAR	Structures and Improvements	4.25%
E322	NUCLEAR	Reactor Plant Equipment	3.63%
E323	NUCLEAR	Turbogenerator Units	1.60%
E324	NUCLEAR	Accessory Electric Equipment	2.10%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.49%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.59%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.72%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	3.95%
E332	HYDRO	Reservoirs, Dams and Waterways	3.95%
E333	HYDRO	Water Wheels, Turbines & Generators	3.95%
E334	HYDRO	Accessory Electric Equipment	3.95%
E335	HYDRO	Miscellaneous Power Plant Equipment	3.95%
E340.1	OTHER	Wind Rights	4.01%
E341	OTHER	Structures and Improvements	4.51%
E342	OTHER	Fuel Holders, Producers & Accessories	2.92%
E344	OTHER	Generators	3.39%
E345	OTHER	Accessory Electric Equipment	3.58%
E346	OTHER	Miscellaneous Power Plant Equipment	5.56%
E348	OTHER	Energy Storage Equipment – Production	0.00%

TRANSMISSION

E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.54%
*E352	Structures and Improvements-Prod.	1.54%
E353	Station Equipment	2.03%
*E353	Station Equipment-Prod.	2.03%
E354	Towers and Fixtures	1.88%
*E354	Towers and Fixtures-Prod.	1.92%
E355	Poles and Fixtures	2.15%
*E355	Poles and Fixtures-Prod.	2.19%
E356	Overhead Conductors & Devices	2.10%
*E356	Overhead Conductors & Devices-Prod.	2.14%
E357	Underground Conduit	1.37%
E358	Underground Conductors & Devices	1.84%

DISTRIBUTION

E361	Structures and Improvements	2.20%
*E361	Structures and Improvements-Prod.	2.17%
E362	Station Equipment	2.22%
*E362	Station Equipment-Prod.	2.18%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	4.35%
E365	Overhead Conductors and Devices	2.99%
E366	Underground Conduit	2.05%
E367	Underground Conductor and Devices	2.22%
E368	Line Transformers	3.21%
E368	Line Capacitors	4.29%
E369	Overhead Services	3.95%
E369	Underground Services	2.58%
E370	Meters	6.59%
E370.1	Meters-Old	0.00%
E373	Street Lighting and Signal Systems	4.61%

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	2.12%
E391	Office Furniture and Equipment	5.07%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	10.97%
E392	Transportation Equipment – Light Truck	8.41%
E392	Transportation Equipment – Trailers	6.95%
E392	Transportation Equipment – Heavy Trucks	7.24%
E393	Stores Equipment	5.00%
E394	Tools, Shop and Garage Equipment	6.67%
E394	Hand Held Meter Readers	0.00%
E395	Laboratory Equipment	10.00%
E396	Power Operated Equipment	8.41%
E397	Communication Equipment	11.11%
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2014 CONTRACT YEAR

NSP(Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	4.61%
E312	STEAM	Boiler Plant Equipment	3.65%
E314	STEAM	Turbogenerator Units	4.36%
E315	STEAM	Accessory Electric Equipment	4.21%
E316	STEAM	Miscellaneous Power Plant Equipment	2.23%
E302	HYDRO	Franchises & Consents	3.85%
E331	HYDRO	Structures and Improvements	3.40%
E332	HYDRO	Reservoirs, Dams and Waterways	3.43%
E333	HYDRO	Water Wheels, Turbines & Generators	2.54%
E334	HYDRO	Accessory Electric Equipment	3.44%
E335	HYDRO	Miscellaneous Power Plant Equipment	3.56%
E341	OTHER	Structures and Improvements	1.68%
E342	OTHER	Fuel Holders, Producers & Accessories	1.63%
E343	OTHER	Prime Movers	1.90%
E344	OTHER	Generators	1.54%
E345	OTHER	Accessory Electric Equipment	1.26%
E346	OTHER	Miscellaneous Power Plant Equipment	1.37%
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%

<u>DISTRIBUTION</u>

E361	Structures and Improvements	2.13%
*E361	Structures and Improvements-Prod.	2.12%
E362	Station Equipment	2.44%
*E362	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 Transformers/Other	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	3.22%
E370.2	Meters-AMR	6.53%
E371	Customer Installations	5.01%
E373	Street Lighting and Signal Systems	6.63%

<u>GENERAL - ELECTRIC</u>

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.59%
E391	Office Furniture and Equipment	4.97%
E391	Network Equipment	24.25%
E392	Transportation Equipment – Auto	13.28%
E392	Transportation Equipment – Light	13.51%
E392	Truck	9.81%
E392	Transportation Equipment – Heavy	9.97%
E392	Truck	9.96%
E393	Transportation Equipment –	4.97%4.97%4.75%8.23%6.64%9.05%4.98%
E394	Trailers	
E395	Transportation Equipment – M	
E396	Veh Group 4	
E397	Stores Equipment	
E397	Tools, Shop and Garage	
E398	Equipment	
	Laboratory Equipment	
	Power Operated Equipment	
	Communication Equipment	
	Communication Equipment-EMS	
	Miscellaneous Equipment	

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	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

Exhibit I	-	Formula-type Procedures for Development of Amounts of Power Sales
Exhibit II	-	Formula-type Procedures for Development of Amounts of Energy Sales
Exhibit III	-	Formula-type Procedures for Development of Unit Rates for Power Sales
Exhibit IV	-	Formula-type Procedures for Development of Unit Rates for Energy Sales
Exhibit V	-	Formula-type Procedures for Development of Demand Related Costs
Exhibit VI	-	Formula-type Procedures for Development of Energy Related Costs
Exhibit VII	-	Specification of Rate of Return on Common Equity
Exhibit VIII	-	Specification of Average Monthly Peak Demands
Exhibit IX	-	Specification of Depreciation Rates
Exhibit X	-	Specification of Demand and Energy Classification of Production Expenses

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

"Transmission Loss Multipliers" are equal to:

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

"Transmission Loss Multipliers" are equal to:

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

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

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

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

"Transmission Loss Multipliers" are equal to:

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

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

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

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

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

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

Where:

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

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

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

"Transmission Loss Multipliers" are equal to:

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

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

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

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	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)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

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

C. Fixed Transmission Expense

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

ELECTRIC PLANT IN SERVICE

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

1. Intangible Plant Investment
   Water power 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 ~~346~~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.

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 Mid~~west~~continent Independent ~~Transmission~~ 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.

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.

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.

PLANT HELD FOR FUTURE USE - LAND

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

ELECTRIC CONSTRUCTION WORK IN PROGRESS

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

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 to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) over a period other than the average remaining life. In the 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC ordered NSP (Minn) to amortize the theoretical reserve surplus for transmission, distribution, intangible, and general assets over an eight-year period, commencing January 1, 2013. The NSP (Wis) portion of the reserve is $26,674,271. The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

In its 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868), NSP (Minn) proposed to accelerate the amortization of the theoretical reserve surplus. Specifically, NSP (Minn) proposed that 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. In its order setting interim rates issued January 2, 2014, the MPUC approved the Company's interim rates proposal, subject to refund and hearing procedures. A final MPUC decision is expected in March 2015.

This account is classified to the transmission, distribution, intangible and general functions of plant.

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	NSP (Wis) Actual to Theoretical Reserve Difference (Remaining Balance as of Jan. 1, 2014)
Intangible 1/	$417,044	$365,054	$0	$0
Transmission	200,466,880	149,597,398	26,645,321	23,314,656
Distribution 2/	109,362,353	109,362,353	18,051	15,795
General	6,727,378	5,888,716	10,899	9,536
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271	$23,339,987

If the final MPUC order in the 2014 test year rate case approves an amortization of the theoretical depreciation reserve different from th~~ose~~at approved for interim rates, NSP (Minn) proposes to true-up the impact in 2015.

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.

OTHER

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

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

RETURN ON RATE BASE

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

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

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

Equity Return:

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

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

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

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

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

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

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

8. Income Tax Base

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

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

12. Federal and State Income Taxes

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

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

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

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

NSP Company (Minnesota)

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

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

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

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

NSP Company (Wisconsin):

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

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

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

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

Income Tax Depreciation

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

Interest Expense

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

Preferred Dividend Credit

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

DEPRECIATION AND AMORTIZATION EXPENSE

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

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

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 for purposes of amortizing the NSP (Wis) portion ($26,674,271) of the NSP (Minn) theoretical reserve surplus amortization, as calculated on Exhibit V, Schedule 4.2. These amounts are in accordance with the Minnesota Public Utilities Commission (MPUC) decisions listed in Exhibit V, Schedule 4.2. The September 3, 2013 MPUC order in the 2013 NSP (Minn) test year rate case (Docket No. E002/GR-12-961) included an 8 year amortization period beginning January 1, 2013. The January 2, 2014 MPUC order setting interim rates in the 2014 NSP (Minn) test year rate case (Docket No. E002/GR-13-868) accepted the first year of NSP (Minn)'s proposal to amortize 50 percent of the remaining theoretical reserve surplus in 2014, subject to refund and hearing procedures. A final MPUC decision is expected in March 2015.

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)

Theoretical Reserve Surplus Amortization Expense represents the current year amortization of the total theoretical depreciation reserve surplus over the amortization period determined by the MPUC. If the final MPUC order in the 2014 test year rate case approves an amortization of the theoretical depreciation reserve different from that approved for interim rates, NSP (Minn) proposes to true-up the impact in 2015.

Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset)[1], by the plant functional classifications.

[1] When the amortization is completed, NSP (Minn) and NSP (Wis) will make a section 205 filing with the Commission to add FERC Account 407.3 (reduction of Regulatory Asset), or other appropriate account, to this Schedule 8.1, to amortize the Theoretical Reserve Surplus regulatory asset over the average remaining lives of the functional classes of assets.

PROVISION FOR DEFERRED INCOME TAXES

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

PROPERTY TAXES

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

INSURANCE EXPENSE

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

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

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

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

~~Production~~ 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.

NET PURCHASED POWER DEMAND COSTS

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

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

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

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

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

CREDITS FOR PRODUCTION-RELATED SERVICES

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

CREDITS FOR TRANSMISSION RELATED SERVICES

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

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)		

FUEL EXPENSES

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

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

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

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

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

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power 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.

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

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

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

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year ~~2013~~2014 Contract Year

Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
~~2011~~2012	January	5371~~5582~~	1031~~1017~~	6402~~6599~~
	February	4967~~5488~~	966~~1021~~	5933~~6509~~
	March	5020~~5205~~	921~~943~~	5941~~6147~~
	April	4710~~4794~~	879~~887~~	5590~~5682~~
	May	6067~~5239~~	948~~998~~	7015~~6237~~
	June	7409~~7696~~	1149~~1283~~	8558~~8979~~
	July	8049~~8083~~	1337~~1348~~	9386~~9431~~
	August	7433~~7157~~	1228~~1078~~	8661~~8235~~
	September	7005~~7367~~	1220~~1231~~	8225~~8598~~
	October	4914~~5469~~	963~~886~~	5877~~6355~~
	November	5210~~5170~~	1007~~928~~	6216~~6098~~
	December	5382~~5389~~	1027~~1013~~	6409~~6403~~
	Total	71,536~~72,638~~	12,675~~12,634~~	84,211~~85,272~~
~~2012~~2013	January	5559~~5385~~	1112~~1031~~	6671~~6415~~
	February	5316~~5017~~	1030~~966~~	6346~~5983~~
	March	5012~~5055~~	978~~921~~	5990~~5975~~
	April	4762~~4730~~	894~~879~~	5656~~5608~~
	May	5433~~6089~~	845~~947~~	6278~~7036~~
	June	6898~~7413~~	1111~~1148~~	8009~~8561~~
	July	7303~~7355~~	1302~~1317~~	8605~~8672~~
	August	7353~~7398~~	1252~~1274~~	8605~~8672~~
	September	6670~~6810~~	1186~~1243~~	7856~~8053~~
	October	5151~~5260~~	916~~945~~	6067~~6206~~
	November	5342~~5244~~	1007~~997~~	6350~~6241~~
	December	5462~~5557~~	1064~~1097~~	6526~~6653~~
	Total	70,262~~71,312~~	12,698~~12,764~~	82,961~~84,076~~
~~2013~~2014	January	5662~~5496~~	1078~~1062~~	6740~~6558~~
	February	5536~~5351~~	1064~~1039~~	6600~~6390~~
	March	5108~~5075~~	1015~~916~~	6123~~5991~~
	April	4920~~4757~~	949~~949~~	5869~~5706~~
	May	5871~~6041~~	1039~~1077~~	6910~~7118~~
	June	7400~~7183~~	1263~~1299~~	8663~~8482~~
	July	7335~~7184~~	1327~~1298~~	8662~~8482~~
	August	7384~~7199~~	1277~~1282~~	8661~~8481~~
	September	6705~~6834~~	1215~~1253~~	7920~~8087~~
	October	5183~~5283~~	937~~957~~	6120~~6240~~
	November	5389~~5256~~	1037~~1009~~	6426~~6265~~
	December	5511~~5571~~	1090~~1107~~	6601~~6678~~
	Total	72,003~~71,229~~	13,292~~13,249~~	85,295~~84,478~~

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

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2013~~2014 CONTRACT YEAR

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

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~3.15%~~4.75%
E312	STEAM	Boiler Plant Equipment	~~3.42%~~3.48%
E314	STEAM	Turbogenerator Units	~~3.52%~~3.53%
E315	STEAM	Accessory Electric Equipment	~~3.00%~~3.08%
E316	STEAM	Miscellaneous Power Plant Equipment	~~2.84%~~3.68%
~~E302~~	~~NUCLEAR~~	~~Franchises & Consents~~	~~4.91%~~
E302	NUCLEAR	Franchises & Consents	4.49%
E321	NUCLEAR	Structures and Improvements	~~2.42%~~4.25%
E322	NUCLEAR	Reactor Plant Equipment	~~2.60%~~3.63%
E323	NUCLEAR	Turbogenerator Units	~~3.40%~~1.60%
E324	NUCLEAR	Accessory Electric Equipment	~~2.55%~~2.10%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	~~2.24%~~4.49%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.59%
~~E325~~	~~NUCLEAR~~	~~Decommissioning FERC Wisconsin Jurisdiction~~	~~0.00%~~
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	~~0.71%~~0.72%
~~E302~~	~~HYDRO~~	~~Franchises & Consents~~	~~3.74%~~
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	~~0.92%~~3.95%
E332	HYDRO	Reservoirs, Dams and Waterways	~~2.91%~~3.95%
E333	HYDRO	Water Wheels, Turbines & Generators	~~4.65%~~3.95%
E334	HYDRO	Accessory Electric Equipment	~~4.64%~~3.95%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~1.09%~~3.95%
E340.1	OTHER	Wind Rights	~~3.14%~~4.01%
E341	OTHER	Structures and Improvements	~~3.08%~~4.51%
E342	OTHER	Fuel Holders, Producers & Accessories	~~2.91%~~2.92%
E344	OTHER	Generators	~~3.63%~~3.39%
E345	OTHER	Accessory Electric Equipment	~~3.32%~~3.58%
E346	OTHER	Miscellaneous Power Plant Equipment	~~3.52%~~5.56%
E348	OTHER	Energy Storage Equipment – Production	0.00%

TRANSMISSION

E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.54%
*E352	Structures and Improvements-Prod.	1.54%
E353	Station Equipment	2.03%
*E353	Station Equipment-Prod.	2.03%
E354	Towers and Fixtures	1.88%
*E354	Towers and Fixtures-Prod.	1.92%
E355	Poles and Fixtures	2.15%
*E355	Poles and Fixtures-Prod.	2.19%
E356	Overhead Conductors & Devices	2.10%
*E356	Overhead Conductors & Devices-Prod.	2.14%
E357	Underground Conduit	1.37%
E358	Underground Conductors & Devices	1.84%

DISTRIBUTION

E361	Structures and Improvements	~~2.28%~~2.20%
*E361	Structures and Improvements-Prod.	~~2.18%~~2.17%
E362	Station Equipment	~~2.19%~~2.22%
*E362	Station Equipment-Prod.	2.18%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	~~4.64%~~4.35%
E365	Overhead Conductors and Devices	~~2.79%~~2.99%
E366	Underground Conduit	~~2.10%~~2.05%
E367	Underground Conductor and Devices	~~2.07%~~2.22%
E368	Line Transformers	~~3.07%~~3.21%
E368	Line Capacitors	~~4.53%~~4.29%
E369	Overhead Services	~~4.50%~~3.95%
E369	Underground Services	~~3.12%~~2.58%
E370	Meters	~~5.75%~~6.59%
E370.1	Meters-Old	0.00%
E373	Street Lighting and Signal Systems	~~4.59%~~4.61%

GENERAL - ELECTRIC
~~GENERAL - ELECTRIC~~

E303	Intangible Plant – 5 Year	20.00%
E390	Structures and Improvements	~~2.29%~~2.12%
E391	Office Furniture and Equipment	~~5.22%~~5.07%
E391	Network Equipment	25.00%
E392	Transportation Equipment – Auto	~~16.40%~~10.97%
E392	Transportation Equipment – Light Truck	~~9.15%~~8.41%
E392	Transportation Equipment – Trailers	~~8.38%~~6.95%
E392	Transportation Equipment – Heavy Trucks	~~7.62%~~7.24%
E393	Stores Equipment	~~5.34%~~5.00%
E394	Tools, Shop and Garage Equipment	~~6.44%~~6.67%
E394	Hand Held Meter Readers	0.00%
E395	Laboratory Equipment	~~8.39%~~10.00%
E396	Power Operated Equipment	~~8.30%~~8.41%
E397	Communication Equipment	~~10.50%~~11.11%
E397	Communication Equipment-AMR	~~6.70%~~6.67%
E398	Miscellaneous Equipment	~~7.32%~~6.67%

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2014 CONTRACT YEAR

NSP(Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	~~3.28%~~4.61%
E312	STEAM	Boiler Plant Equipment	~~3.47%~~3.65%
E314	STEAM	Turbogenerator Units	~~3.56%~~4.36%
E315	STEAM	Accessory Electric Equipment	~~3.65%~~4.21%
E316	STEAM	Miscellaneous Power Plant Equipment	~~3.82%~~2.23%
E302	HYDRO	Franchises & Consents	~~3.53%~~3.85%
E331	HYDRO	Structures and Improvements	~~2.98%~~3.40%
E332	HYDRO	Reservoirs, Dams ~~&~~and Waterways	~~2.79%~~3.43%
E333	HYDRO	Water Wheels, Turbines & Generators	~~3.49%~~2.54%
E334	HYDRO	Accessory Electric Equipment	~~3.10%~~3.44%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~2.91%~~3.56%
E341	OTHER	Structures and Improvements	~~1.12%~~1.68%
E342	OTHER	Fuel Holders, Producers & Accessories	~~1.14%~~1.63%
E343	OTHER	Prime Movers	~~1.10%~~1.90%
E344	OTHER	Generators	~~1.24%~~1.54%
E345	OTHER	Accessory Electric Equipment	~~1.62%~~1.26%
E346	OTHER	Miscellaneous Power Plant Equipment	~~1.64%~~1.37%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	~~3.09%~~2.01%
*E352		Structures and Improvements-Prod.	~~3.10%~~1.98%
E353		Station Equipment	~~3.25%~~2.58%
*E353		Station Equipment-Prod.	~~3.26%~~2.33%
E354		Towers and Fixtures	~~2.77%~~1.73%
E355		Poles and Fixtures	~~2.97%~~2.99%
E356		Overhead Conductors & Devices	~~2.96%~~2.60%
E357		Underground Conduit	~~2.39%~~2.08%
E358		Underground Conductors & Devices	~~1.45%~~2.73%
E359		Roads and Trails	~~2.24%~~1.43%

DISTRIBUTION

E361	Structures and Improvements	~~3.00%~~2.13%
*E361	Structures and Improvements-Prod.	~~2.99%~~2.12%
E362	Station Equipment	~~3.10%~~2.44%
*E362	Station Equipment-Prod.	~~3.12%~~2.41%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	~~3.64%~~5.48%
E365	Overhead Conductors and Devices	~~3.43%~~4.28%
E366	Underground Conduit	~~3.22%~~1.80%
E367	Underground Conductor and Devices	~~3.21%~~2.73%
E368	Line Transformers	~~3.61%~~2.56%
E368	Line Transformers/Other	~~3.61%~~2.56%
E368	Line Capacitors	~~3.66%~~3.09%
E369	Overhead Services	~~3.93%~~4.02%
E369	Underground Services	~~3.93%~~2.78%
E370	Meters	~~4.00%~~3.99%
E370.1	Meters-Old	~~4.17%~~3.22%
E370.2	Meters-AMR	~~4.50%~~6.53%
E371	Customer Installations	~~2.84%~~5.01%
E373	Street Lighting and Signal Systems	~~6.38%~~6.63%

~~ELECTRIC GENERAL~~ GENERAL - ELECTRIC

E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	~~2.86%~~2.59%
E391	Office Furniture and Equipment	~~5.00%~~4.97%
E391	Network Equipment	~~25.00%~~24.25%
E392	Transportation Equipment – Auto	~~12.86%~~13.28%
E392	Transportation Equipment – Light Truck	~~12.86%~~13.51%
E392	Transportation Equipment – Heavy Truck	~~9.00%~~9.81%
E392	Transportation Equipment – Trailers	9.97%
E392	Transportation Equipment – M Veh Group 4	9.96%
E393	Stores Equipment	~~5.00%~~4.97%
E394	Tools, Shop and Garage Equipment	~~5.00%~~4.97%
E395	Laboratory Equipment	~~5.00%~~4.75%
E396	Power Operated Equipment	~~7.50%~~8.23%
E397	Communication Equipment	~~6.67%~~6.64%
E397	Communication Equipment-EMS	~~9.09%~~9.05%
E398	Miscellaneous Equipment	~~5.00%~~4.98%

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

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

SPECIFICATIONS OF DEMAND AND ENERGY CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
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