Department of Energy
Western Area Power Administration
Upper Great Plains Region
P.O. Box 35800
Billings, MT 59107-5800

April 2, 2007

Dear Transmission Customers and Other Interested Parties:

Enclosed is the Integrated System (IS) Transmission and Ancillary Services Rate Calculation which will be effective May 1, 2007. The rates are as follows:

Service	Rate Schedule	Rate
Network Transmission	UGP-NT1	Load-ratio share of 1/12 of the Annual Revenue Requirement for IS Transmission Service of $134,878,205.
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $2.78/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 3.81 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$57.20/schedule/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.08/kWmonth
Regulation and Frequency Response	UGP-AS3	$0.06/kWmonth
Energy Imbalance	UGP-AS4	For negative excursions outside of 3 percent bandwidth, the Upper Great Plains Region reserves the right to charge 100 mills/kWh. Positive excursions outside the bandwidth will be lost to the system.
Spinning/Supplemental Reserves	UGP-AS5 and 6	$0.14/kWmonth of customer load

The IS Transmission Loss Factor effective May 1, 2007, is 4 percent and unchanged from the previous 2-year period.

If you have any questions concerning the IS Transmission and Ancillary Services Rate Calculation, please telephone Lloyd Linke at (605) 882-7500.

Sincerely,

Robert J. Harris

Robert J. Harris
Regional Manager

Enclosure

Integrated System Transmission and Ancillary Services Rate Calculation

Western Area Power Administration
Basin Electric Power Cooperative
Heartland Consumers Power District

Effective May 1, 2007

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective May 1, 2007

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Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
2006

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		
4	Basin Electric	$39,865,324	Basin Electric Revenue Requirement Worksheet
5	Western	$98,770,765	Western Annual IS Transmission Costs Worksheet, L69
6	Heartland	$203,726	Heartland IS Tariff Worksheet
7		$138,839,815	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$346,565	MRES Irv Simmons Revenue Requirement Worksheet
12		$3,021,763	NWPS Revenue Requirement Worksheet
13		$3,368,328	
14			
15			
16	**Transmission Revenue Credits**		
17			
18	Short-Term Firm Point-to-Point Transmission Service Credit		
19		($309,950)	
20			
21	Non-Firm Point-to-Point Transmission Service Credit		
22		($33,447)	
23			
24	Revenue from Existing Transmission Agreements		
25		($6,504,693)	
26			
27	Scheduling, System Control and Dispatch Service Credit		
28		($481,848)	
29			
30			
31	**Annual Revenue Requirement for IS Transmission Service**		
32			
33		$134,878,205	L7 + L13 + L19 + L22 + L25 + L28

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
2006

Line No.			Notes
1			
2			
3	Annual Revenue Requirement for IS Transmission Service		Notes
4			
5		$134,878,205	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	IS Transmission System Total Load		
9			
10		4,036,000 KW	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo		
14			
15	**$2.78 / KW-Mo**		L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
2006

Line No.			Notes
1			
2			
3	Firm Point-to-Point Transmission Rate in $/KW-Mo		Notes
4			
5		$2.78 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	Maximum Non-Firm Point-to-Point Transmission Rate		
10		**3.81 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2006

A.	Fixed Charge Rate	22.337%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,233,192	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,626,008	(A x B)
D.	FY 2006 Number of Daily Schedules	63,388	
E.	Rate for Scheduling, System Control and Dispatch Service ($/schedule/day)	**$57.20**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2005.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (38.4%) and communication facilities plant (68.8%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2002 Pick-Sloan and Fort Peck Results of Operations Schedule 1, the Transmission Plant-in-Service worksheet, and the Net Plant Investment worksheet.)

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2006 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$1,758,264	(1)
B.	BEPC & HCPD Reactive Service Revenue Requirement	$1,642,198	(2)
C.	MRES Reactive Service Revenue Requirement	$371,323	(3)
D.	Total Reactive Revenue Requirement	$3,771,785	(A+B+C)
E.	2006 IS Transmission System Total Load (kW-Yr)	4,045,000	(4)
F.	Annual Reactive Charge ($/kW-Yr)	$0.93	(D/E)
G.	Monthly Reactive Charge ($/kW-Mo)	$0.08	(F/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2005, Western's Costs".

(2) Basin Electric cost support data.

(3) Missouri River Energy Services cost support data.

(4) IS Firm Long Term Peak Transmission plus IS Short Term Firm Point-to-Point.

Rate for Reserves for 2006

A.	Fixed Charge Rate	18.115%	(1)	
B.	Generation Net Plant Costs	$ 480,501,178	(2)	
C.	Annual Cost of Generation	$ 87,042,788	(A x B)	
D.	Plant Capacity (kW)	2,539,000		
E.	Cost/kW ($/kW)	$ 34.28	(C / D)	
F.	Monthly Charge ($/kW-mo)	$ 2.86	(E / 12 months)	
G.	Western's Load (kW-Yr)	1,553,000	(3)	
H.	Capacity used for Reserves (kW)	77,650	(Gx5%)	(4)
I.	Annual Reserves Revenue Requirement	$ 2,661,842	(E x H)	
J.	Annual Charge ($/kW-Yr)	$ 1.71	(I /G)	
K.	Monthly Charge ($/kW-mo)	$ 0.14	(J/12)	

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2005.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less total generation plant depreciation.

(3) Average of Western's monthly peaks for 2006.

(4) MAPP operating reserve requirement.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2006
(Integrated System)

A.	Western Regulation Revenue Requirement	$1,456,591	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$90,709	(2)
C.	Total Regulation Revenue Requirement	$1,547,300	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,193,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.71	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.06	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2005, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2006 Watertown Control Area.

Integrated System Load Data

2006 IS Transmission System Total Load
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	01/16/06	1900	3,370	529	3,899
2	02/17/06	800	3,719	538	4,257
3	03/20/06	2000	3,251	477	3,728
4	04/03/06	900	2,939	481	3,420
5	05/31/06	1700	3,004	480	3,484
6	06/30/06	1600	3,836	474	4,310
7	07/28/06	1700	4,365	469	4,834
8	08/03/06	1800	4,013	479	4,492
9	09/07/06	1800	3,154	480	3,634
10	10/30/06	1900	3,381	474	3,855
11	11/29/06	1900	3,767	481	4,248
12	12/07/06	800	3,788	481	4,269
13					
14	**12 CP**		3,549	487	4,036

2006 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 5, 2005	19:00	1932 MW	85 MW	2017 MW
February 8, 2005	9:00	2181 MW	101 MW	2282 MW
March 1, 2005	8:00	1805 MW	75 MW	1880 MW
April 28, 2005	10:00	1734 MW	67 MW	1801 MW
May 23, 2005	17:00	1792 MW	77 MW	1869 MW
June 22, 2005	17:00	2188 MW	103 MW	2291 MW
July 20, 2005	18:00	2440 MW	123 MW	2563 MW
August 8, 2005	18:00	2225 MW	110 MW	2335 MW
September 9, 2005	17:00	1891 MW	85 MW	1976 MW
October 25, 2005	8:00	2169 MW	78 MW	2247 MW
November 16, 2005	19:00	2466 MW	93 MW	2559 MW
December 6, 2005	19:00	2405 MW	94 MW	2499 MW
Total		25,228	1091	26,319
			Average Control Area Load	2,193

(1) The East Control Area Load has the NWPS surplus and MDU loads removed.

(2) The West Control Area Load does not have the NorthWestern Energy- Montana load removed.

Western's
Transmission Cost Data

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
1			
2	**A. Operation and Maintenance Expense for Transmission**		
3			
4	Transmission O&M Expense	$42,146,271	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$42,146,271	L4 ÷ L5
7			
8	Net Transmission Plant Investment	$442,204,357	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.531%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$11,551,752	A&G Expenses Worksheet, C6L15
16			
17	Net Transmission Plant Investment	$442,204,357	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.612%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$19,825,936	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$442,204,357	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.483%	L24/L26

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
29			
30			
31	**D. Taxes Other than Income Taxes for Transmission**		
32			
33	Not applicable.		
34			
35			
36	**E. Allocation of General Plant to Transmission**		
37			
38	No General Plant identified at this time, all plant is identified as either generation or transmission related.		
39			
40			
41	**F. Cost of Capital**		
42			
43	Weighted Transmission Composite Interest Rate	5.710%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.531%	L10
49			
50	A&G Expense	2.612%	L19
51			
52	Depreciation Expense	4.483%	L28
53			
54	Taxes Other than Income Taxes	0.000%	
55			
56	Allocation of General Plant to Transmission	0.000%	

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
57			
58	Cost of Capital	5.710%	L43
59			
60	Total	22.336%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	22.336%	L60
66			
67	Net Transmission Plant Investment	$442,204,357	L8
68			
69	Annual Western-UGPR Transmission Cost	$98,770,765	L65 * L67
70			

Transmission Revenue from Existing Agreements
Pick Sloan Missouri Basin Program - Eastern Division
FY 2006

Line No.	Description	Amount
1		
2	Montana-Dakota Utilities Company	$465,363
3	MAPP	$3,969,086
4		
5	Total	$4,434,449

O&M Expenses
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	**Total Electric Operating Expense**	281,891,218	92,431,762			374,322,980
3						
4	**Less:**					
5	**Other Power Supply Expenses**	224,560,947	58,827,201			283,388,148
6	**A&G Expenses**	12,198,513	6,582,546			18,781,059
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	1,360,299	1,863,564			3,223,863
9						
10	**Plus:**					
11	**Moveable Property Interest**	627,995	363,536			991,531
12	**Warehouse Stores Interest**	90,121	101,890			192,011
13						
14	**COE/BOR Total**			30,581,076	29,707,289	60,288,365
15	**PS Total O&M**	44,489,575	25,623,877	30,581,076	29,707,289	130,401,817
16						
17	**PS-ED Transmission O&M 4/**	41,900,282	245,989	0	0	42,146,271
18						
19	**PS-ED Generation O&M 5/**	1,170,076	0	30,581,076	29,707,289	61,458,441

1/ All Western UGPR O&M Expenses are from the FY 2005 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from Schedule 5.

2/ All Western RMR O&M Expenses are from the FY 2005 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from Schedule 5.

3/ Total BOR and Corps O&M Expenses are from the FY 2005 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14.

4/ The portion of O&M expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

5/ The portion of O&M expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

DEPRECIATION EXPENSE
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR	(3) WESTERN RMR	(4) COE	(5) BOR	(6) Total
1						
2	PS Depreciation Expense	20,915,709 1/	13,283,403 2/	27,570,173 3/	4,005,489 4/	65,774,774
3						
4	PS-ED Transmission Depreciation 5/	19,698,415	127,521	0	0	19,825,936
5						
6	PS-ED Generation Depreciation 6/	550,083	0	27,570,173	4,005,489	32,125,745

1/ FY 2005 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2005 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2005 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet. COE transmission depreciation is actual COE switchyard depreciation.

6/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet. COE generation depreciation is COE total depreciation less transmission depreciation.

A&G Expenses
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1) Object Class	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	1411	2,663,521	1,616,628	0	0	4,280,149
3	1412	1,641,218	1,784,869	0	0	3,426,087
4	1415	(179,073)	(122,660)	0	0	(301,733)
5	1416	(64,945)	(51,387)	0	0	(116,332)
6	1431	0	0	0	0	0
7	1432	0	0	0	0	0
8	1441	4,673,143	2,673,588	0	0	7,346,731
9	1442	3,464,649	681,508	0	0	4,146,157
10	2541	0	0	0	0	0
11	2596	0	0	0	0	0
11	25DA	0	0	0	0	0
12	25DH	0	0	0	0	0
13	**PS Total A&G**	12,198,513	6,582,546	0	0	18,781,059
14						
15	**PS-ED Transmission A&G 4/**	11,488,560	63,192	0	0	11,551,752
16						
17	**PS-ED Generation A&G 5/**	320,821	0	0	0	320,821

1/ Western UGPR A&G Expenses are from the FY 2005 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11A.

2/ Western RMR A&G Expenses are from the FY 2005 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11A.

3/ A&G Expenses for COE and BOR are unavailable. All COE and BOR A&G expenses are included in O&M Expenses.

4/ The portion of A&G expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

5/ The portion of A&G expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

NET PLANT INVESTMENT
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total
1										
2	Total PS Plant-in-Service	879,018,587	1/	564,442,612	2/	903,283,702	3/	407,451,634	12/	2,754,196,535
3	PS-ED Transmission Plant-in-Service	827,875,999	4/	5,422,857	5/	0	6/	0		833,298,856
4	PS-ED Generation Plant-in-Service	23,076,026	7/	0		903,283,702	L2-L3	407,451,634	L2-L3	1,333,811,362
5	Generation Plant to Total Plant	0.0263	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.9418	L3/L2	0.0096	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	413,163,008	8/	205,997,667	9/	493,767,805	10/	195,664,413	11/	1,308,592,893
9	PS-ED Trans. Accumulated Depreciation	389,116,921	L6*L8	1,977,578	L6*L8	0	13/	0	L6*L8	391,094,499
10	PS-ED Gen. Accumulated Depreciation	10,866,187	L5*L8	0	L5*L8	493,767,805	L8-L9	195,664,413	L5*L8	700,298,405
11	PS-ED Net Transmission Plant	438,759,078	L3-L9	3,445,279	L3-L9	0	L3-L9	0	L3-L9	442,204,357
12	PS-ED Net Generation Plant	12,209,839	L4-L10	0	L4-L10	409,515,897	L4-L10	211,787,221	L4-L10	633,512,957

1/ Transmission Plant-in-Service Worksheet, C2L498.
2/ FY 2005 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2005 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L498.
5/ Transmission Plant-in-Service Worksheet, C5L507.
6/ Transmission Plant-in-Service Worksheet, C5L511.
7/ Transmission Plant-in-Service Worksheet, C4L498.
8/ FY 2005 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2005 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2005 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2005 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2005 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ FY 2005 accumulated depreciation on the COE switchyards.

COST OF CAPITAL
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total	
1											
2	**Long Term Debt:**										
3	FY 2005 Balances	495,888,267	1/	303,111,972	1/	454,274,506	1/	82,529,545	1/	1,335,804,290	
4											
5	**Interest Expenses:**										
6	FY 2005 Simple Interest	28,269,604	2/	21,561,406	2/	14,398,227	2/	3,702,215	2/	67,931,452	
7	Average Interest Rate	5.701%	L6/L3	7.113%	L6/L3	3.169%	L6/L3	4.486%	L6/L3		
8	Transmission Plant Factor	0.9935	3/	0.0065	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.710%	7/
10	Generation Plant Factor	0.0173	8/	0.0000	9/	0.6772	10/	0.3055	11/		
11	Weighted Gen. Composite Rate									3.615%	12/

1/ FY 2005 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2005 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
3/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
4/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
5/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
6/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
7/ (C2L7*C2L8)+(C3L7*C3L8)+(C4L7*C4L8)+(C5L7*C5L8).
8/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
9/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
10/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
11/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
12/ (C2L7*C2L10)+(C3L7*C3L10)+(C4L7*C4L10)+(C5L7*C5L10).

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
1	Transmission Lines					
2	AURORA- BROOKINGS 115-KV T/L	$133,157.92			133,158	
3	AURORA-FLANDREAU 115-KV T/L	$96,623.18			96,623	
4	BEULAH-GARRISON	$352,214.17			352,214	
5	BISMARCK-GLENHAM	$5,000,750.15			5,000,750	
6	BISMARCK-JAMESTOWN NO. 1	$5,473,497.34			5,473,497	
7	BISMARCK-JAMESTOWN NO. 2	$3,096,816.00			3,096,816	
8	BISMARCK-MEDORA	$4,783,893.45			4,783,893	
9	BROOKINGS-SIOUX FALLS	$1,174,861.20			1,174,861	
10	BROOKINGS-WATERTOWN NO. 2	$645,505.24			645,505	
11	BROOKINGS-WATERTOWN NO. 3	$3,318,557.94			3,318,558	
12	BROOKINGS-WHITE 115/230KV	$2,952,236.87			2,952,237	
13	CARRINGTON-JAMESTOWN	$377,544.10			377,544	
14	CHARLIE CREEK-BELFIELD	$13,674,183.41			13,674,183	
15	CONRAD-SHELBY #3	$5,804,318.27			5,804,318	
16	CRESTON-MARYVILLE	$1,366,481.00			1,366,481	
17	DAWSON COUNTY - MILES CITY	$2,622,978.36			2,622,978	
18	DAWSON-GLENDIVE	$553,799.83			553,800	
19	DAWSON-MEDORA	$2,867,800.05			2,867,800	
20	DAWSON-O'FALLON CREEK	$317,413.05			317,413	
21	DAWSON-WILLISTON	$1,258,899.68			1,258,900	
22	DENISON-CRESTON	$3,978,012.94			3,978,013	
23	DEVILS LAKE-CARRINGTON	$7,237,287.85			7,237,288	
24	DEVILS LAKE-LAKOTA	$1,872,141.80			1,872,142	
25	EDGELEY-FORMAN	$377,081.25			377,081	
26	EDGELEY-GROTON	$771,572.37			771,572	
27	ELK CREEK-NEWELL-MAURINE 115-kV T/L	$60,704.18			60,704	
28	FARGO-GRAND FORKS	$2,369,098.07			2,369,098	
29	FARGO-MORRIS	$6,910,157.41			6,910,157	
30	FORMAN-SUMMIT (BISMARCK)	$922,097.72			922,098	
31	FORMAN-SUMMIT (HURON)	$487,533.50			487,534	
32	FORT PECK-DAWSON #1	$493,203.21			493,203	
33	FORT PECK-DAWSON #2	$6,060,933.88			6,060,934	
34	FORT PECK-HAVRE	$28,773,463.87			28,773,464	
35	FORT PECK-WHATELY	$160,325.00			160,325	
36	FORT PECK-WILLISTON	$6,057,421.40			6,057,421	
37	FORT RANDALL-FORT THOMPSON 1&2	$6,717,268.81			6,717,269	
38	FORT RANDALL-GAVIN'S POINT	$1,014,592.54			1,014,593	
39	FORT RANDALL-GREGORY	$630,776.48			630,776	
40	FORT RANDALL-MT VERNON	$967,828.17			967,828	
41	FORT RANDALL-O'NEILL	$502,230.00			502,230	
42	FORT RANDALL-SIOUX CITY 1&2	$8,532,124.61			8,532,125	
43	FORT THOMPSON-GRAND ISLAND	$16,397,505.05			16,397,505	
44	FORT THOMPSON-HURON 230-KV 1&2	$3,990,211.34			3,990,211	
45	FORT THOMPSON-SIOUX FALLS 1&2	$9,542,122.27			9,542,122	
46	FT. PECK-WOLF POINT #2 230/115-KV	$7,663,746.77			7,663,747	
47	GARRISON-BISMARCK 230KV 1&2	$5,176,777.72			5,176,778	
48	GARRISON-JAMESTOWN	$4,306,775.15			4,306,775	
49	GARRISON-MALLARD	$1,266,644.80			1,266,645	
50	GARRISON-WM. J. NEAL	$545,452.00			545,452	
51	GAVINS POINT-BELDEN	$455,727.00			455,727	
52	GAVINS POINT-SIOUX FALLS	$1,331,321.00			1,331,321	
53	GRANITE FALLS- MORRIS	$3,279,089.40			3,279,089	
54	GRANITE FALLS-MINNESOTA VALLEY	$156,778.00			156,778	
55	GREAT FALLS-CONRAD	$12,811,701.91			12,811,702	
56	GREGORY-MISSION	$2,148,291.45			2,148,291	
57	GROTON-HURON	$1,212,199.37			1,212,199	
58	GROTON-SUMMIT	$2,739,189.45			2,739,189	
59	HAVRE-RAINBOW	$505,537.57			505,538	
60	HAVRE-SHELBY#2	$5,561,904.64			5,561,905	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
61	HESKETT-DEVAUL	$434,208.50			434,209	
62	HETTINGER-NEW UNDERWOOD	$10,966,326.96			10,966,327	
63	HURON-MT VERNON	$617,622.68			617,623	
64	HURON-WATERTOWN 230KV 1&3	$4,886,323.14			4,886,323	
65	JAMESTOWN-EDGELEY	$324,360.39			324,360	
66	JAMESTOWN-FARGO NO. 1	$3,963,118.87			3,963,119	
67	JAMESTOWN-FARGO NO. 2	$3,155,849.87			3,155,850	
68	JAMESTOWN-GRAND FORKS	$13,584,610.95			13,584,611	
69	JAMESTOWN-VALLEY CITY	$1,051,927.92			1,051,928	
70	LEEDS-DEVILS LAKE	$2,151,246.63			2,151,247	
71	LEEDS-ROLLA	$322,882.88			322,883	
72	MALLARD-RUGBY	$1,282,435.85			1,282,436	
73	MARTIN-MISSION	$750,437.49			750,437	
74	MARTIN-PHILIP	$794,022.00			794,022	
75	MAURINE-RAPID CITY	$2,815,118.06			2,815,118	
76	MILES CITY-BAKER	$8,438,591.00			8,438,591	
77	MILES CITY-CUSTER	$3,321,747.26			3,321,747	
78	NEW UNDERWOOD-PHILIP	$2,116,604.94			2,116,605	
79	NEW UNDERWOOD-RAPID CITY NO. 1	$979,279.15			979,279	
80	NEW UNDERWOOD-RAPID CITY NO. 2	$309,991.00			309,991	
81	NEW UNDERWOOD-STEGALL (HURON)	$2,672,946.94			2,672,947	
82	OAHE-FORT THOMPSON 230KV 1&2	$3,149,033.94			3,149,034	
83	OAHE-FORT THOMPSON 230KV 3&4	$5,119,118.61			5,119,119	
84	OAHE-GLENHAM	$4,592,967.53			4,592,968	
85	OAHE-MAURINE	$1,791,779.34			1,791,779	
86	OAHE-NEW UNDERWOOD	$6,447,607.02			6,447,607	
87	OAHE-PIERRE	$388,816.19			388,816	
88	O'FALLON CREEK-MILES CITY	$622,672.25			622,672	
89	PIERRE-PHILIP	$1,187,033.63			1,187,034	
90	RAPID CITY-ELK CREEK 115-kV T/L	$52,063.76			52,064	
91	RUGBY-LEEDS	$226,216.71			226,217	
92	SHELBY-SHELBY#2	$576,089.67			576,090	
93	SIOUX CITY-DENISON	$1,661,310.76			1,661,311	
94	SIOUX CITY-SPENCER	$1,938,352.95			1,938,353	
95	SIOUX FALLS- SIOUX CITY	$3,217,192.17			3,217,192	
96	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	$277,896.62				
97	SUMMIT-WATERTOWN	$6,743,203.05			6,743,203	
98	TIBER TAP-TIBER	$1,084,857.50			1,084,858	
99	UTICA JCT-SIOUX FALLS	$3,496,153.33			3,496,153	
100	VALLEY CITY-FORMAN	$1,527,895.21			1,527,895	
101	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM	$312,931.04			312,931	
102	WATERTOWN-GRANITE FALLS 1&2	$5,269,587.40			5,269,587	
103	WATERTOWN-SIOUX CITY	$26,679,768.73			26,679,769	
104	WATFORD CITY-BEULAH	$1,401,905.02			1,401,905	
105	WILLISTON-WATFORD CITY	$563,079.21			563,079	
106	WM. J. NEAL-RUGBY	$3,436,269.71			3,436,270	
107	YELLOWTAIL-CUSTER	$2,280,202.78			2,280,203	
108	Subtotal	368,842,018	0	0	368,842,018	
109						
110	Substations					
111	ARMOUR SUBSTATION	$2,018,666.06	(82,000)		1,936,666	
112	ASH SUBSTATION	$63,325.31			63,325	
113	AURORA SUBSTATION	$2,899,880.73			2,899,881	
114	BELDEN SUBSTATION	$187,367.19			187,367	
115	BELFIELD SUBSTATION	$8,092,823.69			8,092,824	
116	BERESFORD SUBSTATION	$3,492,462.41	(593,719)		2,898,743	17% of the costs of this facility have been allocated to distribution.
117	BISBEE SUBSTATION	$272,529.27	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution.
118	BISMARK SUBSTATION	$8,576,702.47			8,576,702	
119	BOLE SUB	$20,062.47			20,062	
120	BOLE SUB (BEFP)	$3,177,623.35			3,177,623	
121	BONESTEEL SUBSTATION	$3,366,565.82	(1,683,283)		1,683,283	50% of the costs of this facility have been allocated to distribution.
122	BROOKINGS SUBSTATION	$3,821,278.79			3,821,279	
123	CARRINGTON SUBSTATION	$3,543,522.46	(460,658)		3,082,864	13% of the costs of this facility have been allocated to distribution.

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
124	CIRCLE SUBSTATION	$1,507,470.49			1,507,470	
125	CONRAD SUB	$255,894.14			255,894	
126	CONRAD SUB (BEPS)	$5,188,005.78			5,188,006	
127	CRESTON SUBSTATION	$5,040,654.85	(55,000)		4,985,655	
128	CROSSOVER SUB	$172,081.82			172,082	
129	CROSSOVER SUB	$11,108,808.06			11,108,808	
130	CUSTER SUBSTATION (BEFP)	$2,473,102.76			2,473,103	
131	CUSTER SUBSTATION	$1,872,701.85			1,872,702	
132	CUSTER TRAIL SUBSTATION	$103,149.06	(51,575)		51,574	50% of the costs of this facility have been allocated to distribution.
133	DAWSON COUNTY SUBSTATION	$9,705,450.32	(776,436)		8,929,014	8% of the costs of this facility have been allocated to distribution.
134	DENISON SUBSTATION	$16,018,934.32			16,018,934	
135	DEVAUL SUBSTATION	$867,666.53	(520,600)		347,067	60% of the costs of this facility have been allocated to distribution.
136	DEVILS LAKE SUBSTATION	$2,524,909.81	(277,740)		2,247,170	11% of the costs of this facility have been allocated to distribution.
137	EAGLE BUTTE SUBSTATION	$1,163,201.09			1,163,201	
138	EDGELEY SUBSTATION	$3,315,337.02	(464,147)		2,851,190	14% of the costs of this facility have been allocated to distribution.
139	ELK CREEK SUBSTATION	$2,078,657.27			2,078,657	
140	ELLENDALE SUBSTATION	$217,468.95	(124,000)		93,469	
141	EXIRA SWITCHING STATION	$4,131,968.78			4,131,969	
142	FAITH SUBSTATION	$1,223,906.02	(611,953)		611,953	50% of the costs of this facility have been allocated to distribution.
143	FARGO SUBSTATION	$19,956,502.64	(47,000)		19,909,503	
144	FLANDREAU SUBSTATION	$3,538,787.03	(601,594)		2,937,193	17% of the costs of this facility have been allocated to distribution.
145	FORMAN SUBSTATION	$3,892,710.67	(506,052)		3,386,659	13% of the costs of this facility have been allocated to distribution.
146	FORT RANDALL	$253,780.27			253,780	
147	FORT THOMPSON #2	$7,362,969.63			7,362,970	
148	FORT THOMPSON SUBSTATION	$14,058,748.68	(354,000)		13,704,749	
149	GLENDIVE SUBSTATION	$1,737,087.96			1,737,088	
150	GRAND FORKS SUBSTATION	$9,328,426.85			9,328,427	
151	GRAND ISLAND SUBSTATION	$9,070,638.04			9,070,638	
152	GRANITE FALLS SUBSTATION	$9,692,005.83	(57,000)		9,635,006	
153	GREAT FALLS SUB (BEFP)	$87,833.73			87,834	
154	GREAT FALLS SUB	$470,855.94			470,856	
155	GREGORY SUBSTATION	$1,469,030.71	(293,806)		1,175,225	20% of the costs of this facility have been allocated to distribution.
156	GROTON SUBSTATION	$3,223,857.99			3,223,858	
157	HAVRE SUBSTATION	$6,010,068.28	(1,021,712)		4,988,356	17% of the costs of this facility have been allocated to distribution.
158	HURON SUBSTATION	$11,053,999.16			11,053,999	
159	JAMESTOWN SUBSTATION	$19,166,418.94	(1,916,642)		17,249,777	10% of the costs of this facility have been allocated to distribution.
160	KILLDEER SUBSTATION	$266,926.80			266,927	
161	LAKOTA SUBSTATION	$1,599,215.72	(527,741)		1,071,475	33% of the costs of this facility have been allocated to distribution.
162	LEEDS SUBSTATION	$980,360.55	(137,250)		843,111	14% of the costs of this facility have been allocated to distribution.
163	MARTIN SUBSTATION	$653,491.63			653,492	
164	MARYVILLE SUBSTATION	$1,525.00			1,525	
165	MAURINE SUBSTATION	$5,652,050.81			5,652,051	
166	MIDLAND SUBSTATION	$676,395.81			676,396	
167	MILES CITY #2	$1,007,302.85			1,007,303	
168	MILES CITY SUB #3	$2,202,460.98			2,202,461	
169	MILES CITY SUBSTATION (BEFP)	$160,336.34			160,336	
170	MILES CITY SUBSTATION	$5,640,431.84			5,640,432	
171	MISSION SUBSTATION	$2,507,204.19			2,507,204	
172	MORRIS SUBSTATION	$4,560,669.80			4,560,670	
173	MT VERNON SUBSTATION	$1,036,939.65			1,036,940	
174	NEW UNDERWOOD SUBSTATION	$7,319,797.23	(805,178)		6,514,619	11% of the costs of this facility have been allocated to distribution.
175	NEWELL SUBSTATION	$979,875.36			979,875	
176	Non-Facility	$250,035.99			250,036	
177	O'FALLON CREEK SUBSTATION	$2,261,957.17	(1,130,979)		1,130,978	50% of the costs of this facility have been allocated to distribution.
178	PHILIP SUBSTATION	$1,739,097.77			1,739,098	
179	PIERRE SUBSTATION	$4,291,265.55	(2,145,633)		2,145,633	50% of the costs of this facility have been allocated to distribution.
180	RAINBOW SUBSTATION	$723,556.12			723,556	
181	RAPID CITY SUBSTATION	$3,712,450.14			3,712,450	
182	RICHLAND SUBSTATION	$1,458,733.93	(1,166,987)		291,747	80% of the costs of this facility have been allocated to distribution.
183	ROLLA SUBSTATION	$979,520.44	(244,880)		734,640	25% of the costs of this facility have been allocated to distribution.
184	RUDYARD SUBSTATION	$2,469,782.39	(419,863)		2,049,919	17% of the costs of this facility have been allocated to distribution.
185	RUGBY SUBSTATION	$6,193,897.03	(867,146)		5,326,751	14% of the costs of this facility have been allocated to distribution.
186	SAVAGE SUB	$74,402.89			74,403	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
187	SHELBY SUBSTATION	$1,050,358.95			1,050,359	
188	SHELBY SUBSTATION #2 (BEFP)	$194,287.82			194,288	
189	SHELBY SUBSTATION #2 (BEPS)	$4,194,040.87			4,194,041	
190	SIOUX CITY #2	$9,381,796.34			9,381,796	
191	SIOUX CITY SUBSTATION	$15,201,490.75	(57,000)		15,144,491	
192	SIOUX FALLS SUBSTATION	$6,310,420.28			6,310,420	
193	SPENCER	$3,240,714.97			3,240,715	
194	SULLY BUTTES	$74,427.83			74,428	
195	SUMMIT SUBSTATION	$2,740,512.85			2,740,513	
196	TYNDALL SUBSTATION	$880,286.23			880,286	
197	UTICA JCT.	$139,640.96			139,641	
198	VALLEY CITY SUBSTATION	$2,926,247.75			2,926,248	
199	VERONA	$25,210.13			25,210	
200	VIRGIL FODNESS SUBSTATION	$2,524,096.48			2,524,096	
201	WALL SUBSTATION	$1,495,431.64	(747,716)		747,716	50% of the costs of this facility have been allocated to distribution.
202	WASHBURN SUBSTATION	$1,421,618.70			1,421,619	
203	WATERTOWN #2	$2,968,648.79			2,968,649	
204	WATERTOWN STATIC VAR SYSTEM	$11,703,689.27			11,703,689	
205	WATERTOWN SUBSTATION	$10,140,474.18			10,140,474	
206	WATFORD CITY SUB	$1,030,525.88	(30,000)		1,000,526	
207	WHATELY (NORTHERN)	$40,859.63			40,860	
208	WHATELY SUBSTATION	$104,408.65	(52,204)		52,205	50% of the costs of this facility have been allocated to distribution.
209	WHITE 345/115 SUB	$8,774,692.38			8,774,692	
210	WICKSVILLE SUBSTATION	$660,601.41	(330,301)		330,300	50% of the costs of this facility have been allocated to distribution.
211	WILLISTON SUBSTATION	$6,715,283.27			6,715,283	
212	WINNER SUBSTATION	$3,222,334.86	(1,611,167)		1,611,168	50% of the costs of this facility have been allocated to distribution.
213	WOLF POINT SUBSTATION	$7,296,850.18	(2,189,055)		5,107,795	30% of the costs of this facility have been allocated to distribution.
214	WOONSOCKET SUBSTATION	$1,063,436.83			1,063,437	
215	YANKTON SUBSTATION	$302,095.12			302,095	
216	Subtotal	394,100,068	(23,098,282)	0	371,001,786	
217						
218	**Line Taps & Related Equipment**					
219	ANITA	$6,259.21			6,259	
220	ASSINNIBOINE	$35,004.78			35,005	
221	BAKER (BEFP)	$133,554.26			133,554	
222	BAKER	$97,831.84			97,832	
223	CANYON FERRY	$15,144.73			15,145	
224	CANYON FERRY	$72,350.85			72,351	
225	CHARLIE CREEK	$1,119,512.94			1,119,513	
226	CHINOOK	$3,943.04			3,943	
227	COTTON	$1,399.06			1,399	
228	DICKINSON	$63,735.83			63,736	
229	E. J. MANNING	$51,273.95			51,274	
230	EAGLE	$156,285.34			156,285	
231	FORSYTH	$32,069.70			32,070	
232	FORSYTH	$273,368.24			273,368	
233	HARLEM	$220,801.65			220,802	
234	HETTINGER	$4,451.01			4,451	
235	HIGHWOOD	$22,896.21			22,896	
236	LAKE PLATTE	$2,628.16			2,628	
237	MALLARD	$12,833.40			12,833	
238	MALTA	$28,180.66			28,181	
239	NASHUA SUB	$72,367.83			72,368	
240	O'NEILL SUB (NPP)	$115,789.96			115,790	
241	POPLAR (MDU)	$3,758.31			3,758	
242	PRIMGHAR	$575.04			575	
243	SPALDING	$22,234.28			22,234	
244	STANLEY	$49,735.05			49,735	
245	STEGALL 230KV (BCPS)	$3,599.00			3,599	
246	TERRY TAP	$64,792.21			64,792	
247	TERRY TAP	$371,751.26	(185,876)		185,875	50% of the costs of this facility have been allocated to distribution.
248	TIBER TAP	$166,305.58	(83,153)		83,153	50% of the costs of this facility have been allocated to distribution.
249	V. T. HANLON	$8,748.75			8,749	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
250	WITTEN	$25,430.00			25,430	
251	WM. J. NEAL	$9,918.91			9,919	
252	YANKTON JCT.	$30,753.21			30,753	
253	ZENITH	$2,047.18			2,047	
254	Subtotal	3,301,331	(269,029)	0	3,032,302	
255						
256	O&M Service & Maintenance Centers					
257	ARMOUR O&M SER. CEN.	$895,999.84			896,000	
258	BISMARCK O&M SER. CEN.	$7,204,785.33			7,204,785	
259	DAWSON SER. CEN.	$22,545.10			22,545	
260	DEVILS LAKE O&M SER. CEN.	$173,367.61			173,368	
261	Fargo Line Maintenance Facility	$849,999.50			850,000	
262	FARGO O&M SER. CEN.	$794,988.13			794,988	
263	FORT PECK SER. CEN.	$1,003,139.01			1,003,139	
264	FORT THOMPSON O&M S. C.	$261,767.06			261,767	
265	HAVRE SERVICE CENTER	$191,340.59			191,341	
266	HURON O&M SER. CEN.	$2,447,467.29			2,447,467	
267	JAMESTOWN O&M SER. CEN.	$994,207.64			994,208	
268	MILES CITY MTCE FAC.	$21,816.75			21,817	
269	MILES CITY MTCE FAC.	$1,003,437.32			1,003,437	
270	NEW UNDERWOOD SER. CEN.	$96,884.41			96,884	
271	PHILIP O&M SER. CENT.	$1,705,194.71			1,705,195	
272	PIERRE O&M SER. CEN.	$1,047,818.04			1,047,818	
273	RAPID CITY GARAGE & STOR.	$2,055,931.92			2,055,932	
274	SIOUX CITY O&M SER. CEN.	$3,009,019.03			3,009,019	
275	SIOUX FALLS O&M SER. CEN.	$77,456.44			77,456	
276	WATERTOWN MAINT. CEN.	$1,203,651.10			1,203,651	
277	Subtotal	25,060,817	0	0	25,060,817	
278						
279	Operation Centers					
280	WATERTOWN OPERATIONS CENT	$1,975,501.72		(632,161)	1,343,341	
281	WATERTOWN OPER CTR (BFPS)	$11,303,988.91		(3,617,276)	7,686,713	Column 4 shows 32.0% of the Watertown Operations Center that was prorated to generation based on FTE associated with generation.
282	Subtotal	13,279,491	0	(4,249,437)	9,030,054	
283						
284	Mobile Equipment				0	
285	MOB 115KV SWITCH TRAILER	$12,328.00			12,328	
286	MOB 115KV SWITCH TRAILER	$57,412.75			57,413	
287	MOB TRANSF 111KV 15MVA	$213,000.00			213,000	
288	MOB TRANSF 115KV 10MVA	$76,258.00			76,258	
289	MOB TRANSF 115KV 10MVA	$142,234.84			142,235	
290	MOB TRANSF 115KV 25MVA	$556,464.43			556,464	
291	MOB TRANSF 115KV 40MVA	$499,220.26			499,220	
292	MOB TRANSF 230KV 1-33MVA	$170,278.00			170,278	
293	MOBILE BY PASS KIT (BISMARCK)	$35,070.98			35,071	
294	MOBILE BY PASS KIT (FT.PECK)	$7,038.00			7,038	
295	MOBILE BY PASS KIT (HURON)	$163,694.91			163,695	
296	MOBILE SUB 110KV	$127,143.62			127,144	
297	MOBILE SUB 115KV 20MVA	$404,166.08			404,166	
298	MOBILE SUB 41.8 KV	$192,498.02			192,498	
299	MOBILE SUB 69KV	$71,118.00			71,118	
300	MOB SH.REACTOR	$179,327.81			179,328	
301	Subtotal	2,907,254	0	0	2,907,254	
302						
303	Transmission-Related Generation Facilities					
304	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	$81,944.00		(81,944)	0	
305	CANYON FERRY-EAST HELENA "A"	$141,044.00		(141,044)	0	
306	CANYON FERRY-EAST HELENA "B"	$141,044.00		(141,044)	0	
307	FORT PECK POWERPLANT (COE)	$5,286,537.23		(5,286,537)	0	
308	FORT THOMPSON-BIG BEND NO. 1	$922,163.82		(922,164)	0	
309	FORT THOMPSON-BIG BEND NO. 2	$690,735.13		(690,735)	0	
310	Subtotal	7,263,468	0	(7,263,468)	0	
311						
312	Communication Facilities				0	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
313	ATLANTIC COMMUNICATION SITE	$17,199.41		(5,359)	11,840	Column 4 shows 31.16% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation.
314	BAKER RELAY	$27,791.28		(8,660)	19,131	
315	BANTRY	$55,420.91		(17,269)	38,152	
316	BARRETT	$244,695.30		(76,247)	168,448	
317	BATTLE MT. MICROWAVE	$463,563.04		(144,446)	319,117	
318	BELLE PRAIRIE	$16,110.97		(5,020)	11,091	
319	BELLE PRAIRIE	$577,323.35		(179,894)	397,429	
320	BENEDICT	$36,771.72		(11,458)	25,314	
321	BEULAH	$21,155.88		(6,592)	14,564	
322	BIG BEND	$113,361.84		(35,324)	78,038	
323	BIJOU REPEATER	$603,314.75		(187,993)	415,322	
324	BISMARCK REPEATER	$421,391.23		(131,306)	290,085	
325	BISON REPEATER	$210,846.39		(65,700)	145,146	
326	BRINSMADE	$215,245.49		(67,070)	148,175	
327	BRISTOL	$11,441.22		(3,565)	7,876	
328	BRUNSVILLE REPEATER	$201,619.13		(62,825)	138,794	
329	BUFFALO	$255,050.57		(79,474)	175,577	
330	CAHOON	$234,523.27		(73,077)	161,446	
331	CARRINGTON REPEATER	$741,252.99		(230,974)	510,279	
332	CHARTER OAK REPEATER	$12,545.79		(3,909)	8,637	
333	CHARTER OAK REPEATER	$3,121.00		(973)	2,148	
334	CHINOOK (BEFP)	$284,048.28		(88,509)	195,539	
335	CHINOOK REPEATER	$15,293.08		(4,765)	10,528	
336	CLARK MW REPEATER	$588,027.14		(183,229)	404,798	
337	CLEVELAND REPEATER, N.D.	$263,617.34		(82,143)	181,474	
338	COLEMAN REPEATER	$288,293.92		(89,832)	198,462	
339	COLOME REPEATER	$469,004.51		(146,142)	322,863	
340	CONRAD BUTTE REPEATER	$370,461.79		(115,436)	255,026	
341	CONRAD BUTTE REPEATER	$117,595.27		(36,643)	80,952	
342	CROW LAKE REPEATER	$311,803.34		(97,158)	214,645	
343	CROWN BUTTE	$203,198.15		(63,317)	139,881	
344	CULBERTSON RADIO RELAY SITE	$22,729.00		(7,082)	15,647	
345	CUSTER LOOKOUT	$203,979.14		(63,560)	140,419	
346	DALTON (WES)	$198,020.76		(61,703)	136,318	
347	DEVILS LAKE REPEATER	$496,231.04		(154,626)	341,605	
348	DODSON REPEATER	$276,811.78		(86,255)	190,557	
349	DOGDEN BUTTE	$274,023.83		(85,386)	188,638	
350	DRISCOLL	$196,774.32		(61,315)	135,459	
351	DUPREE REPEATER	$1,821.43		(568)	1,253	
352	DUTTON REPEATER	$260,358.08		(81,128)	179,230	
353	EAST RAINY BUTTE	$270,849.02		(84,397)	186,452	
354	ECKELSON	$288,401.37		(89,866)	198,535	
355	ELKTON	$323,756.30		(100,882)	222,874	
356	ELLENDALE REPEATER	$330,513.26		(102,988)	227,525	
357	ELLSWORTH AIR BASE	$59,668.55		(18,593)	41,076	
358	ERHARD	$312,148.26		(97,265)	214,883	
359	EXIRA REPEATER	$50,556.02		(15,753)	34,803	
360	F. L. BLAIR	$39,437.33		(12,289)	27,148	
361	FAIRPOINT REPEATER	$339,030.39		(105,642)	233,388	
362	FALLON REPEATER	$271,939.04		(84,736)	187,203	
363	FLOWING WELLS	$68,763.06		(21,427)	47,336	
364	FORBES COMMUNICATION SITE	$45,316.06		(14,120)	31,196	
365	FORT PECK RELAY (WES)	$250,959.53		(78,199)	172,761	
366	FORT THOMPSON REPEATER	$306,861.40		(95,618)	211,243	
367	FORT THOMPSON REPEATER (EAST RIVER)	$301,613.97		(93,983)	207,631	
368	FOX CREEK MICROWAVE	$579,063.41		(180,436)	398,627	
369	FRYBURG SUB & MICROWAVE	$210,966.62		(65,737)	145,230	
370	GARRISON	$193,068.91		(60,160)	132,909	
371	GARY REPEATER	$228,493.55		(71,199)	157,295	
372	GAVIN'S POINT	$169,008.84		(52,663)	116,346	
373	GAVINS POINT REPEATER	$278,567.67		(86,802)	191,766	
374	GETTYSBURG REPEATER	$296,476.20		(92,382)	204,094	
375	GRAND FORKS MINNKOTA (MPC)	$22,643.50		(7,056)	15,588	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
376	HAILSTONE BUTTE	$174,962.63		(54,518)	120,445	
377	HALLOWAY REPEATER	$266,614.17		(83,077)	183,537	
378	HATHAWAY	$209,090.52		(65,153)	143,938	
379	HELENA RELAY (LAND ONLY)	$422.00		(131)	291	
380	HERMOSA MICROWAVE	$302,700.91		(94,322)	208,379	
381	HIGHLAND REPEATER	$177,963.52		(55,453)	122,511	
382	HIGHMORE REPEATER	$251,511.29		(78,371)	173,140	
383	HINSDALE	$201,837.42		(62,893)	138,944	
384	HINSDALE REPEATER	$25,152.91		(7,838)	17,315	
385	HOPEWELL REPEATER	$384,133.10		(119,696)	264,437	
386	HUNTER MICROWAVE	$333,962.36		(104,063)	229,899	
387	HURON DISTRICT OFFICE	$817,927.45		(254,866)	563,061	
388	HYSHAM	$259,920.49		(80,991)	178,929	
389	JAMESTOWN REPEATER	$90,628.08		(28,240)	62,388	
390	JONES CREEK	$251,033.91		(78,222)	172,812	
391	KELLY CREEK	$15,210.26		(4,740)	10,470	
392	KELLY CREEK	$300,277.28		(93,566)	206,711	
393	KILLDEER REPEATER	$393,258.07		(122,539)	270,719	
394	KNEE HILL MW	$308,285.26		(96,062)	212,223	
395	KNEE HILL MW	$119,303.04		(37,175)	82,128	
396	KONES CORNER REPEATER	$470,206.91		(146,516)	323,691	
397	LAC QUI PARLE	$747,618.69		(232,958)	514,661	
398	LAKE ANDES REPEATER	$743,351.63		(231,628)	511,724	
399	LEFOR	$188,834.86		(58,841)	129,994	
400	LINDSAY RIDGE	$235,489.14		(73,378)	162,111	
401	LODGEPOLE REPEATER	$186,559.45		(58,132)	128,427	
402	MAKOSHIKA	$1,401.00		(437)	964	
403	MALTA REPEATER	$289,598.79		(90,239)	199,360	
404	MANDAN MICROWAVE SITE	$69,987.59		(21,808)	48,180	
405	MAPLE RIVER	$172,792.24		(53,842)	118,950	
406	MARTIN REPEATER	$288,354.34		(89,851)	198,503	
407	MAYVILLE	$369,575.26		(115,160)	254,415	
408	MIDLAND REPEATER	$660,338.82		(205,762)	454,577	
409	MILES CITY SUB (BEFP)	$305,417.90		(95,168)	210,250	
410	MOE REPEATER	$317,410.58		(98,905)	218,506	
411	MOORHEAD	$251,422.35		(78,343)	173,079	
412	MORRIS REPEATER & MICROWAVE	$24,820.50		(7,734)	17,087	
413	MORRIS REPEATER & MICROWAVE	$299,932.72		(93,459)	206,474	
414	NEWCASTLE REPEATER	$216,330.02		(67,408)	148,922	
415	OAHE	$440,320.79		(137,204)	303,117	
416	O'KREEK REPEATER	$508,753.93		(158,528)	350,226	
417	ORCHARD REPEATER	$51,067.67		(15,913)	35,155	
418	OTO MICROWAVE	$16,445.21		(5,124)	11,321	
419	OTTUMWA ROAD REPEATER SITE	$7,684.53		(2,394)	5,291	
420	PAGE N.D.	$1,646.00		(513)	1,133	
421	PAHOJA SUB	$66,444.02		(20,704)	45,740	
422	PEAK	$269,132.89		(83,862)	185,271	
423	PHILIP JCT. REPEATER	$545,124.57		(169,861)	375,264	
424	PICKSTOWN REPEATER	$10,134.00		(3,158)	6,976	
425	PINE RIDGE	$15,765.53		(4,913)	10,853	
426	PINE RIDGE	$273,893.58		(85,345)	188,549	
427	PRIMGHAR REPEATER	$11,989.79		(3,736)	8,254	
428	PUKWANNA REPEATER	$255,427.42		(79,591)	175,836	
429	RAPID CITY REPEATER	$341,292.17		(106,347)	234,945	
430	RICHARDSON COULEE	$207,294.95		(64,593)	142,702	
431	RICHARDSON COULEE REPEATER	$24,536.19		(7,645)	16,891	
432	RICHLAND MW REPEATER (BEPS)	$532,826.91		(166,029)	366,798	
433	ROCKY RIDGE REPEATER	$226,933.71		(70,713)	156,221	
434	ROLLAG	$172,921.71		(53,882)	119,040	
435	RUGBY REPEATER	$291,249.14		(90,753)	200,496	
436	RUTLAND	$29,927.19		(9,325)	20,602	
437	SACO	$1,237.00		(385)	852	
438	SENTINEL BUTTE	$224,545.68		(69,968)	154,578	

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
439	SHEEP COULEE REPEATER	$517,298.41		(161,190)	356,108	
440	SIOUX CITY REPEATER	$576,462.33		(179,626)	396,836	
441	SIOUX FALLS REPEATER	$367,833.38		(114,617)	253,216	
442	SIOUX PASS	$42,197.79		(13,149)	29,049	
443	SNAKE BUTTE REPEATER	$732,730.01		(228,319)	504,411	
444	SPALDING REPEATER	$36,491.45		(11,371)	25,120	
445	SPIRIT MOUND	$226,292.67		(70,513)	155,780	
446	STRASBERG	$17,869.93		(5,568)	12,302	
447	SUMMIT REPEATER	$50,053.17		(15,597)	34,456	
448	TAPPEN REPEATER	$283,205.56		(88,247)	194,959	
449	TENNANT COMMUNICATIONS SITE	$8,781.54		(2,736)	6,046	
450	TORONTO REPEATER	$285,888.13		(89,083)	196,805	
451	TRIPP REPEATER	$186,047.37		(57,972)	128,075	
452	TRIPP REPEATER	$46,216.16	0	(14,401)	31,815	
453	TURKEY RIDGE REPEATER	$569,163.14		(177,351)	391,812	
454	TYLER REPEATER	$449,771.36		(140,149)	309,622	
455	VIDA	$14,357.45		(4,474)	9,883	
456	VIDA	$323,155.65		(100,695)	222,461	
457	WALL REPEATER	$454,607.17		(141,656)	312,951	
458	WATERTOWN REPEATER	$682,036.57		(212,523)	469,514	
459	WAYSIDE	$118,155.65		(36,817)	81,339	
460	WESSINGTON SPGS. REPEATER	$565,164.16		(176,105)	389,059	
461	WESTFIELD	$42,273.05		(13,172)	29,101	
462	WHITE SWAN	$116,529.47		(36,311)	80,218	
463	WHITLOCK (BCPS)	$117,921.59		(36,744)	81,178	
464	WOLBACH REPEATER	$52,848.48		(16,468)	36,380	
465	YELLOWTAIL PP (BEPS)	$88,909.07		(27,704)	61,205	
466	YELLOWTAIL SWITCHYARD (BEPS)	$271,476.13		(84,592)	186,884	
467	(DELETE) ZERO (PROPOSED)	$50,948.12		(15,875)	35,073	
468	Subtotal	37,108,857	0	(11,563,121)	25,545,736	
469						
470	Miles City Converter Station					
471	MILES CITY CONVERTER STATION	$21,595,941.85			21,595,942	
472	MILES CITY CONVERTER STATION	$860,089.15			860,089	
473	Subtotal	22,456,031	0	0	22,456,031	
474						
475	Distribution Facilities					
476	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	$190,465.19	(190,465)		0	
477	BUFORD TRENTON PUMP SUB	$657,833.85	(657,834)		0	These facilities have been determined to be used solely for distribution
478	FALLON PUMPING PLANT SUBS	$223,594.20	(223,594)		0	and are therefore not recovered in the transmission rate.
479	FALLON RELIFT PUMPING PLA	$171,256.71	(171,257)		0	
480	FALLON-GLENDIVE PUMP #4	$27,758.00	(27,758)		0	
481	FORT PECK-WOLF POINT	$234,539.69	(234,540)		0	
482	FRAZER PUMP SUB	$253,597.44	(253,597)		0	
483	GARRISON-SNAKE CREEK	$569,241.37	(569,241)		0	
484	GLENDIVE P.P. #1 SUB.	$425,706.26	(425,706)		0	
485	INTAKE SUBSTATION	$108,040.31	(108,040)		0	
486	INTAKE-INTAKE PUMP	$6,494.00	(6,494)		0	
487	KINSEY PUMP	$49,256.00	(49,256)		0	
488	SAVAGE PUMPING PLANT SUBS	$102,282.90	(102,283)		0	
489	SHIRLEY PUMP SUBSTATION	$166,016.66	(166,017)		0	
490	SNAKE CREEK PUMP SUBSTATI	$662,435.45	(662,435)		0	
491	SOUTH DAKOTA SCHOOL OF MINES AND TECHNOLOGY	$19,074.86	(19,075)		0	
492	TERRY PUMPING PLANT SWITC	$474,403.84	(474,404)		0	
493	TERRY PUMPING PLANT SWITC	$180.00	(180)		0	
494	TIBER DAM SUBSTATION	$318,567.85	(318,568)		0	
495	WIOTA SUBSTATION	$38,507.00	(38,507)		0	
496	Subtotal Distribution Facilities	4,699,252	(4,699,251)	0	1	
497						
498	Subtotal Upper Great Plains Region Facilities	879,018,587	(28,066,562)	(23,076,026) 0	827,875,999	
499						
500						
501						

Line No.	(1) DESCRIPTION	(2) FY2005 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
502	**Rocky Mountain Region Facilities**					
503	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1. These are RMR facilities utilized by both RMR and UGPR. The amount in Column 5 will be recovered by UGPR.
504	STEGALL SUBSTATION	8,760,202	(8,457,593)		302,609	
505	STEGALL-WAYSIDE	2,978,205			2,978,205	
506	YELLOWTAIL SWITCHYARD	7,416,827	(5,562,620)		1,854,207	
507		19,443,070	(14,020,213)	0	5,422,857	
508						
509	**Corps of Engineers Facilities**					
510	CORPS SWITCHYARD FACILITIES	29,782,666		(29,782,666)	0	
511		29,782,666	0	(29,782,666)	0	
512						
513	TOTAL FACILITIES	928,244,323	(42,086,775)	(52,858,692)	833,298,856	

Western's Ancillary Services Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2006 (WESTERN'S COSTS)

A. Fixed Charge Rate	18.115%	(1)
B. Generation Net Plant Costs ($)	$480,501,178	(2)
C. Annual Cost of Generation ($)	$87,042,788	(A x B)
D. Capability Used for Reactive Support (%)	2.02%	(3)
E. Reactive Service Revenue Requirement	$1,758,264	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2005.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less Depreciation Reserve.

(3) Five year average peak monthly percentage of condensing generation. Reference PO&M 59 Reports for 1992-1996.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2006
(Western's Costs)

A.	Fixed Charge Rate	17.356%	(1)
B.	Corps Generation Net Plant Costs ($)	179,278,688	(2)
C.	Annual Corps Generation Cost ($)	31,115,609	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	33.21	(C / D)
F.	Capacity Used for Regulation (kW)	43,860	(H x 2%)
G.	Regulation Revenue Requirement ($)	$1,456,591	(E x F)
H.	Load in Control Area(s) (kW-Yr)	2,193,000	(3)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2005.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/05.

(3) Average of monthly peaks for 2006 Watertown Control Area.

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Generation**		
3			
4	Generation O&M Expense	$61,458,441	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$646,214,975	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	9.511%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$320,821	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$646,214,975	L6
16			
17	A&G as % of Net Generation Plant Investment	0.050%	L13/L15
18			
19			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	$32,125,745	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$646,214,975	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	4.971%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Generation**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.583%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	9.511%	L8
47			
48	A&G Expense	0.050%	L17
49			
50	Depreciation Expense	4.971%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	3.583%	L41
57			
58	Total	18.115%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	18.115%	L59
64			
65	Net Generation Plant Investment	$646,214,975	L6
66			
67	Western Annual Generation Revenue Requirement	$117,061,843	L63 * L65
68			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Corps Generation**		
3			
4	Corps Generation O&M Expense	$30,581,076	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$422,203,067	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	7.243%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L17
14			
15	Net Corps Generation Plant Investment	$422,203,067	L6
16			
17	A&G as % of Net Generation Plant Investment	0.000%	L13/L15
18			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
19			
20	**C. Depreciation Expense for Corps Generation**		
21			
22	Corps Generation Depreciation Expense	$27,570,173	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$422,203,067	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	6.530%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Corps Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Corps Generation**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.583%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Corps Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	7.243%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	6.530%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	3.583%	L41
57			
58	Total	17.356%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	17.356%	L69
64			
65	Net Corps Generation Plant Investment	$422,203,067	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$73,277,564	L63 * L65
68			

Basin Electric's Transmission Cost Data

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

Line No.			Total	Allocator		Total Transmission	IS Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ 69,497,277	$ 39,543,680	$ 29,953,597
	REVENUE CREDITS							
2	Third Party Receipts		$ 2,055,645	TP	1.00000		$ 2,055,645	
3								
4	Third Party Payments		$ 321,644	TP	1.00000		$ 321,644	
5		(line 2 + 4)	$ 1,734,001				$ 1,734,001	
6	NET REVENUE REQUIREMENT	(line 1+ 5)					$ 37,809,679	

Revenue Requirement Worksheet
Utilitizing RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

	(1)	(2) RUS Form 12	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) Other Transmission
	GROSS PLANT IN SERVICE									
1	Production	12h.A.6.	1,828,957,146	NA		-	NA		-	-
2	Transmission	12h.A.11	500,295,865	DA		500,295,865	DA		308,633,608	191,662,256
3	Distribution	12h.A.16	-	NA		-	NA		-	-
4	General	12h.A.17	117,882,227							
4a	Direct Assign - Transmission		36,193,279	DA		36,193,279	DA		27,304,622	8,888,658
4b	Direct Assign - Production		23,095,180	NA		-	NA		-	-
4c	Other		58,593,768	WS	11.020%	6,456,751	WS	(page 4)	3,696,527	2,760,223
5	Intangible	12h.A.1	69,187,682	DA		68,136,267	DA		28,471,286	39,664,981
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18	$ 2,516,322,920			$ 611,082,161			$ 368,106,042	$ 242,976,118
				GP	24.285%		GP		14.629%	9.656%
							TPGP			
	ACCUMULATED DEPRECIATION									
7	Production	12h.B.1-4	930,253,959	NA		-	NA		-	-
8	Transmission	12h.B.5	230,382,281	DA		230,382,281	DA		163,229,636	67,152,645
9	Distribution	12h.B.6	-	NA		-	NA		-	-
10	General	12h.B.7	82,750,345							
10a	Direct Assign - Transmission		24,920,290	DA		24,920,290	DA		20,104,877	4,815,412
10b	Direct Assign - Production		18,446,250	NA		-	NA		-	-
10c	Other		39,383,805	WS	11.020%	4,339,905	WS	(page 4)	2,484,621	1,855,284
11	Intangible	12h.B.12	38,932,310	DA		38,867,093	DA		17,761,478	21,105,614
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18	$ 1,282,318,895			$ 298,509,569			$ 203,580,613	$ 94,928,956
	NET PLANT IN SERVICE									
13	Production	(line 1- line 7)	898,703,187	AUTO		-	AUTO		-	-
14	Transmission	(line 2- line 8)	269,913,584	AUTO		269,913,584	AUTO		145,403,971	124,509,611
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-
16	General	(line 4 - line 10)	35,131,882	AUTO		-	AUTO		-	-
16a	Direct Assign	(line 4a - line 10a)	11,272,990	AUTO		11,272,990	AUTO		7,199,745	4,073,245
16b	Production	(line 4b - line 10b)	4,648,929	AUTO		-	AUTO		-	-
16c	Other	(line 4c - line 10c)	19,209,963	AUTO		2,116,845	AUTO		1,211,906	904,939
17	Intangible	(line 5 - line 11)	30,255,372	AUTO		29,269,174	AUTO		10,709,807	18,559,366
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)	12a.B.L5 less L2	$ 1,234,004,025			$ 312,572,593			$ 164,525,429	$ 148,047,162
				NP	25.330%		NP		13.333%	11.997%

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Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) Other Transmission
	O&M									
1	Transmission less Account 565	12a.A.8.+ A.16.-12I.A.9	17,092,422	TE		-			-	-
2	Direct Assignment (Note A)	Accounting Records	9,055,486	DA		9,055,486	DA		6,658,837	2,396,649
3	Other	Accounting Records	8,036,937	TPW	100.000%	8,036,937	TPW	(page 4)	5,055,012	2,981,924
4	A&G	12a.A.13	35,785,212			-				
5	Less Regulatory Fees	Accounting Records	244,766	NA		-	NA		-	-
6	Production (Note B)	Accounting Records	1,973,114	NA		-	NA		-	-
7	Transmission (Note C)	Accounting Records	700,191	DA/TPW		700,191	DA /TPW	(page 4)	50,398	649,793
8	Headquarters		32,867,141	WS	11.020%	3,621,800	WS		2,073,502	1,548,299
9	TOTAL O&M (sum lines 1 and 4)		$ 52,877,634			$ 21,414,413			$ 13,837,749	$ 7,576,665
	DEBT SERVICE									
10	Interest Expense	12a.A.22-24.	68,251,072	NP	25.330%	17,287,962	NP	(page 2)	9,099,676	8,188,286
11	Principal Payments	12h.H.9.c	87,143,923	NP	25.330%	22,073,511	NP	(page 2)	11,618,594	10,454,918
12	Amort of Debt Discount (428)	12a.A.26	3,487,481							
13	Transmission	Accounting Records	948,071	TPWS	100.000%	948,071	TPWS		480,827	467,244
14	Headquarters	Accounting Records	59,779	WS	11.020%	6,587	WS	(page 4)	3,771	2,816
15	Production	Accounting Records	2,479,631	NA		-	NA		-	-
16	Other Deductions	12a.A.26	3,173,540	NA		-	NA		-	-
17	TOTAL DEBT SERVICE (sum lines 10, 11, 12,16)		$ 162,056,016			$ 40,316,131			$ 21,202,868	$ 19,113,264
	TAXES OTHER THAN INCOME TAXES									
	LABOR RELATED									
18	Payroll		-	NA		-	NA		-	-
19	Highway and vehicle		-	NA		-	NA		-	-
20	PLANT RELATED									
21	Property total	12a.A.21 (less income tax)	1,720,657							
22	Tax Reclassification	Accounting Records	(77,622)	NA	0.000%	-	NA			
23	Gross Receipts (Note D)	12a.A.21	1,798,279	DA		1,798,279	DA		1,361,514	436,766
24	Production		-	NA		-	NA		-	-
25	TOTAL OTHER TAXES		$ 1,720,657			$ 1,798,279			$ 1,361,514	$ 436,766
26	TOTAL OPERATING EXPENSES (Sum 9+17+25)		$ 216,654,307			$ 63,528,824			$ 36,402,130	$ 27,126,694
27	Margin		$ 23,562,831	NP	25.330%	$ 5,968,453	NP	(page 2)	$ 3,141,550	$ 2,826,903
28	REV. REQUIREMENT (sum lines 26+27)		$ 240,217,138			$ 69,497,277			$ 39,543,680	$ 29,953,597

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A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent		(6) IS Transmission	(7) Other Transmission
1	Production		31,650,918					2,244,058	1,675,654
2	Transmission-East		126,944						
3	Transmission-West		351,897	WS	Trans % of total wages	11.020%		6.309%	4.711%
4	Transmission-Allocated		3,440,871						
5	Distribution		-						
6	Other Transmission			TPWS	Trans % of total trans			57.251%	42.749%
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$35,570,630	TPW	West Trans %		(Trans % excluding West)	62.897%	37.103%

IS Transmission Wage and Salary Dollar Split

Line #		Amount	Allocator	Percent
8	Net IS transmission Plant (p.2.c.6.L.14, 16a, 17)	163,313,523		
9	Net Other transmission Plant (p.2.c.7.L.14, 16a,17)	147,142,223		
10	Total (sum lines 8 -9)	$310,455,746		
11	Percent of IS to Total Transmission (Note E)		ISTP	61.528%
12	Percent of Other to total Transmission		Other	38.472%
13	IS Trans Wage & Salary Dollar (L 4 times L 11)	$2,117,113		
14	Other Transmission Wage & Salary (L 4 times L 12)	$1,323,758		
15	Total Transmission Wage and Salary Allocated (L.4)	$3,440,871		

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Note
- A Includes Lease payments of $2,819,842 for member facilities in the IS system and O&M that is charged to specific lines or substations.
- B A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
- C Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
- D SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
  Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
- E MBPP net plant ($45,027,945) is excluded in the percentage calculations on line 11 and 12 as costs for transmission and A&G are directly allocated to MBPP

Basin Electric Power Cooperative
Lines
December 31, 2006

Worksheet 1
Page 1

CPX	Lines	Book Cost	Accum Depr	Net Book	Annual Depreciation
009	230KV LOS#1 to Logan (NSP)	751,708	487,139	264,569	20,689
012	230kv LO#1 DC Line to Washburn	1,485,282	1,450,404	34,878	-
021	345 kv line Stanton to SD Border	9,297,594	7,642,014	1,655,580	258,964
022	345 kv line - SD to Ft Thompson	9,134,431	7,317,302	1,817,129	240,854
023	345 kv line Stanton to SD Border	11,511,850	9,376,874	2,134,975	305,497
024	345 kv line SD to Watertown	10,164,504	7,977,130	2,187,374	312,739
025	230 kv line coal to Logan	4,430,205	3,021,407	1,408,798	110,453
026	230 kv line-230/115/69-sub (16)	289,132	231,447	57,685	8,076
031	115 kv line Logan to Kenmare	3,115,809	2,040,882	1,074,928	74,950
032	115 kv line Logan to Mallard	632,973	401,279	231,694	14,649
034	230 kv line Philip Tap-Philip Sub	853,709	716,334	137,375	23,222
127	345 kv N line #1 dbl circ	10,442,907	4,193,654	6,249,253	199,270
128	345 kv S line #2 dbl circ	11,215,381	4,816,192	6,399,189	202,527
129	500 kv AVS switchyd to SD bdr	57,926,565	25,430,455	32,496,110	1,066,860
130	500 kv SD bdr to Broadland sub	53,098,066	23,215,750	29,882,315	973,967
134	345 kv dbl circ line	942,053	564,889	377,164	27,714
141	230 kv line Broadland to Huron	1,068,625	491,851	576,774	20,646
150	230 kv line Estavan to Sask bdr	15,071,877	9,496,594	5,575,283	391,077
152	345 kv line AVS to Charlie Creek	9,291,907	5,194,787	4,097,120	244,338
185	230 kv line MC-Bowman-NU	9,481,900	6,657,834	2,824,066	271,110
311	115 kv tie line to Groton sub	136,010	82,472	53,539	3,872
361	69KV Line Cornbelt	41,112	3,351	37,762	1,200
411	230 KV Line RC to New Underwood	6,010,877	466,874	5,544,003	144,502
	Total IS Lines	$ 226,394,477	$ 121,276,914	$ 105,117,563	$ 4,917,175

Basin Electric Power Cooperative
Substations
December 31, 2006

Worksheet 1
Page 2

CPX	Substations	Book Cost	Accum Depr	Net Book	Annual Depreciation
013	230KV LO Washburn Substation	71,594	70,298	1,296	-
016	230/115/69KV LO Substation	1,234,995	1,087,201	147,794	26,262
036	345KV FT Thompson Substation	2,374,699	1,830,502	544,197	102,000
039	230/115KV Storla, SD Substation	2,108,942	1,609,987	498,955	89,582
040	230/115KV Philip, SD Substation	862,865	659,585	203,279	38,063
042	230KV Philip,SD Tap Substation	214,957	182,420	32,537	5,884
046	Martin, SD USBR Sub Capacitor Installed	200,287	133,261	67,026	8,340
047	Armour, SD USBR Sub Capacitor Installed	137,379	115,926	21,453	4,013
058	115KV Williston, ND Substation	643,259	426,392	216,867	18,467
060	230/115KV Dickinson, ND Substation	1,204,038	1,014,727	189,311	33,495
061	115KV Spirit Mound Switchyard	1,406,589	1,097,375	309,214	39,305
063	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,967	1,265,442	382,525	52,163
126	500KV Broadland SD, Substation	12,470,254	5,716,381	6,753,873	243,503
142	230KV USBR Huron Substation Addition	1,669,836	774,189	895,647	32,471
145	Manning,ND Sub Capacitor Installed	186,623	141,246	45,377	5,186
153	345/115KV Charlie Creek Substation	5,342,496	3,338,364	2,004,132	146,513
194	Bowman Sub -230 KV breakers	1,393,433	157,139	1,236,294	38,735
195	Hettinger Capacitors	827,735	70,000	757,735	22,789
196	Baker Capacitors	827,735	70,000	757,735	22,789
310	345/115KV Groton Substation Addition	5,019,759	2,880,173	2,139,586	133,601
325	230 mw Miles City DC Tie	18,989,386	11,103,645	7,885,741	525,716
362	69KV Substation - Cornbelt	1,557,920	127,750	1,430,170	45,765
408	RC Tie East Interconnect	1,060,552	95,455	965,098	29,469
470	Groton Clutch	1,872,537	25,769	1,846,768	25,769
711	230KV LO #1 Switchyard and AVS Addition	5,087,828	3,966,188	1,121,641	133,410
720	345/230KV LO#2 Switchyard and AVS Add	16,127,179	9,687,174	6,440,004	388,144
734	Tioga substation - Capacitor bank	387,866	160,128	227,738	10,675
735	345/230KV Watertown Substation	2,871,896	2,428,539	443,357	79,486
737	230/115KV Logan Substation & Sask Addition	4,115,005	2,826,634	1,288,371	110,311
767	345KV AVS Switchyard & Charlie Creek Add't	18,800,068	8,921,091	9,878,978	387,171
	Total IS Substations	**$ 110,715,677**	**$ 61,982,978**	**$ 48,732,699**	**$ 2,799,077**

Basin Electric Power Cooperative
Maintenance Buildings & Microwave
December 31, 2006

Worksheet 1
Page 3

CPX	Maintenance Buildings	Book Cost	Accum Depr	Net Book	Annual Depreciation
070	Mandan Transmission Maint Bldg	6,326,506	4,394,230	1,932,276	236,632
071	Gettysburg Trans Maint Bldg	1,030,782	915,413	115,369	29,816
072	Groton Trans Maint Bldg	2,032,864	864,383	1,168,481	140,749
109	Logan Trans Maint Bldg	1,131,515	916,943	214,572	32,790
119	Broadland Trans Maint Bldg	1,096,289	962,876	133,413	28,135
120	AVS Plantsite Trans Maint Bldg	3,778,418	2,880,024	898,394	73,322
	Total Maintenance Buildings	$ 15,396,374	$ 10,933,869	$ 4,462,506	$ 541,443

CPX	Microwave	Book Cost	Accum Depr	Net Book	Annual Depreciation
043	Microwave - North Dakota	7,550,864	5,613,148	1,937,716	375,458
044	Microwave -South Dakota	3,961,253	2,891,567	1,069,686	216,740
136	Microwave - SD AVS	834,723	653,135	181,588	37,412
137	Microwave - AVS	1,270,496	1,016,711	253,785	54,577
139	Microwave - ND Sask	1,279,463	998,192	281,271	62,849
155	Microwave - ND CC	1,000,407	780,796	219,610	46,119
308	Microwave - SD Groton	143,259	105,192	38,066	7,723
	Subtotal Microwave	$ 16,040,463	$ 12,058,741	$ 3,981,722	$ 800,878
	Non IS transmission 25.794%	(4,137,477)	(3,110,432)	(1,027,045)	(206,579)
	Total Microwave	$ 11,902,986	$ 8,948,309	$ 2,954,677	$ 594,300
	Accum Depr Adjustment		(2,046,078)		
	Total IS Facilities	$ 364,409,515	$ 201,095,992	$ 163,313,523	$ 8,851,995

Basin Electric Power Cooperative
Total Plant
December 31, 2006

Worksheet 2

	Production	IS Transmission	Other	Total Plant In Service
Book Basis-Generation	1,828,957,148	-	-	1,828,957,148
Accum Depr	(944,739,519)	-	-	-944,739,519
G/L Adjust -Accum Depr	14,485,560	-		14,485,560
Net Book	**898,703,189**	-		**898,703,189**
Book Basis-Transmission	2,366,589	308,633,608	189,295,667	500,295,864
Accum Depr	(32,568)	(165,493,153)	(68,505,440)	(234,031,160)
G/L Adjust -Accum Depr	-	2,263,516	1,385,363	3,648,879
Net Book	**2,334,021**	**145,403,971**	**122,175,590**	**269,913,583**
Book Basis General Plant	23,095,180	27,304,622	67,482,426	117,882,227
Accum Depr	(18,262,334)	(19,887,439)	(43,674,120)	(81,823,893)
G/L Adjust -Accum Depr	(183,916)	(217,438)	(525,097)	(926,452)
Net Book General Plant	**4,648,929**	**7,199,745**	**23,283,209**	**35,131,882**
Book Basis Intangibles	1,049,145	28,471,286	39,667,251	69,187,682
Accum Depr	(62,949)	(17,761,478)	(21,107,884)	(38,932,311)
Net Book Intangibles	**986,196**	**10,709,807**	**18,559,367**	**30,255,371**
Total	**906,672,336**	**163,313,523**	**164,018,166**	**1,234,004,025**
Gross Plant				**2,516,322,921**
Accum Depr with Adjustments				(1,282,318,896)
Net Plant				**1,234,004,025**

Basin Electric Power Cooperative
IS Revenue Requirement Worksheet
Third Party Payments and Receipts
December 31, 2006

Worksheet 3

Third Party Payments

ICCUA		224,112
LaCreek		97,532
Total Payments	**$**	**321,644**

Third Party Receipts

ICCUA		338,508
MDU/AVS		132,800
MAPP		1,584,337
Total Receipts	**$**	**2,055,645**

Basin Electric's Ancillary Services Cost Data

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

	East	West	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 260,824,394	$ 73,057,098	$ 17,503,249
Percent of revenue requirement to net plant	44.7590%	31.8468%	16.0142%

Production	LOS	AVS	SM	LRS	Other
$ 351,384,741	$ 98,282,779	$ 161,314,832	$ 1,226,783	$ 73,057,098	$ 17,503,249

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
	GROSS PLANT IN SERVICE										
1	Production	12h.A.6.	1,828,957,146	DA		1,828,957,146	287,010,690	848,204,039	24,930,271	549,462,329	119,349,818
2	Transmission	12h.A.11	500,295,865	NA		-					
3	Distribution	12h.A.16	-	NA		-					
4	General	12h.A.17	117,882,227	WS		-					
4a	Direct Assign - Transmission		36,193,279	NA		-					
4b	Direct Assign - Production		23,095,180	DA		23,095,180	7,326,884	8,916,086	230,428	6,339,228	282,554
4c	Other		58,593,768	WS	88.980%	52,137,017	15,364,765	21,204,648	183,815	15,142,567	241,223
5	Intangible	12h.A.1	69,187,682	NA		1,049,145	-	1,049,145	-	-	-
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18	$ 2,516,322,920			1,905,238,488	309,702,339	879,373,917	25,344,514	570,944,124	119,873,595
				GP	75.715%		12.308%	34.947%	1.007%	22.690%	4.764%
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4	930,253,959	DA		930,253,959	164,236,877	409,310,590	20,315,589	326,016,022	10,374,881
8	Transmission	12h.B.5	230,382,281	NA		-	-	-	-	-	-
9	Distribution	12h.B.6	-	NA		-	-	-	-	-	-
10	General	12h.B.7	82,750,345	WS			-	-	-	-	-
10a	Direct Assign - Transmission		24,920,290	NA		-	-	-	-	-	-
10b	Direct Assign - Production		18,446,250	DA		18,446,250	5,683,306	7,187,247	189,639	5,348,096	37,962
10c	Other		39,383,805	WS	88.980%	35,043,899	10,327,428	14,252,705	123,551	10,178,077	162,138
11	Intangible	12h.B.12	38,932,310	DA		62,949	-	62,949	-	-	-
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18	$ 1,282,318,895			983,807,058	180,247,611	430,813,491	20,628,779	341,542,195	10,574,981
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	898,703,187	AUTO		898,703,187	122,773,813	438,893,449	4,614,682	223,446,307	108,974,937
14	Transmission	(line 2- line 8)	269,913,584	AUTO		-	-	-	-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	-	-	-	-	-
16	General	(line 4 - line 10)	35,131,882	AUTO		-	-	-	-	-	-
16a	Direct Assign	(line 4a - line 10a)	11,272,990	AUTO		-	-	-	-	-	-
16b	Production	(line 4b - line 10b)	4,648,929	AUTO		4,648,929	1,643,578	1,728,638	40,789	991,132	244,592
16c	Other	(line 4c - line 10c)	19,209,963	AUTO		17,093,118	5,037,337	6,951,942	60,264	4,964,490	79,085
17	Intangible	(line 5 - line 11)	30,255,372	AUTO		986,196	-	986,196	-	-	-
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)	12a.B.L5 less L2	$ 1,234,004,025			921,431,430	129,454,728	448,560,426	4,715,735	229,401,929	109,298,614
				NP	74.670%		10.491%	36.350%	0.382%	18.590%	8.857%

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/06

No.	(1)	(2) Reference	(3) Company Total		(4) Allocator	(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
	O&M										
1	Production	12a.A.5.b+ A.15.b	184,005,565	DA		184,005,565	67,031,558	78,147,664	381,270	37,233,891	1,211,181
2	A&G	12a.A.13.b	35,785,212								
3	Less Regulatory Fees	Accounting Records	244,766	NA		-	-	-	-	-	-
4	Production (Note A)		1,973,114	DA	0.000%	1,973,114	-	-	-	1,973,114	-
5	Transmission (Note B)		700,191	NA		-	-	-	-	-	-
6	Headquarters		32,867,141	WS	88.980%	29,245,340	12,146,356	16,762,978	145,312	-	190,695
7	TOTAL O&M (sum lines 1 and 2)		$ 219,790,777			215,224,020	79,177,915	94,910,642	526,582	39,207,006	1,401,876
	DEBT SERVICE										
8	Interest Expense	12a.A.22.-24.b	68,251,072	NP	74.670%	50,963,110	7,159,964	24,809,263	260,821	12,667,906	6,045,157
9	Principal Payments	12h.H.9.c	87,143,923	NP	74.670%	65,070,411	9,141,942	31,676,813	333,020	16,200,096	7,718,540
10	Amort of Debt Discount (428)	12a.A.26.b	3,487,481	NP		-	-	-	-	-	-
11	Transmission	Accounting Records	948,071	NA		-	-	-	-	-	-
12	Headquarters	Accounting Records	59,779	WS	88.980%	53,192	22,092	30,489	264	-	347
13	Production	Accounting Records	2,479,631	DA		2,479,631	308,979	1,322,537	16,052	581,749	250,314
14	Other Deductions	12a.A.26.b	3,173,540	NA		-	-	-	-	-	-
15	TOTAL DEBT SERVICE (Sum lines 8,9,10,14)		$ 162,056,016			118,566,344	16,632,976	57,839,102	610,156	29,469,751	14,014,358
	TAXES OTHER THAN INCOME TAXES										
	LABOR RELATED										
	Payroll		-	WS		-	-	-	-	-	-
16	Highway and vehicle		-	WS		-	-	-	-	-	-
17	PLANT RELATED										
18	Property and Other Total	12a.A.21.b (less income tax)	1,209,995	GP		-	-	-	-	-	-
19	Property Headquarters	Accounting Records	(57,920)	NA	0.000%	-	-	-	-	-	-
20	Gross Receipts Tax	12a.A.21.b (less income tax)	1,267,915	NA		-	-	-	-	-	-
21	Production (Note C)		-	DA		-	-	-	-	-	-
22	TOTAL OTHER TAXES		$ 1,209,995			-	-	-	-	-	-
23	TOTAL OPERATING EXPENSES (Sum 7+15+22)		$ 383,056,788			333,790,364	95,810,891	152,749,744	1,136,738	68,676,757	15,416,234
24	Margin		$ 23,562,831	NP	74.670%	$17,594,378	$2,471,888	$8,565,088	$90,045	$4,380,341	$2,087,015
25	REV. REQUIREMENT (sum lines 23 + 24)		$ 406,619,619		86.416%	$351,384,741	$98,282,779	$161,314,832	$1,226,783	$73,057,098	$17,503,249

Line #	WAGES AND SALARY ALLOCATOR (W/S)									
(1)	(2)	(3) TOTAL	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
1	Production - LOS	$9,327,517	WS	88.980%	$31,650,918	26.223%	36.189%	0.314%	25.843%	0.412%
2	Production - AVS	$12,872,746								
3	Production - SM	$111,589	PRWS			29.470%	40.671%	0.353%	29.044%	0.463%
4	Production - LRS	$9,192,627								
5	Production - Other	$146,440								
6	Transmission	$3,919,712								
7	Other	$0								
	Total Wages and Salaries (exclude adm)	$35,570,630								

Note

A A&G costs directed allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
B Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
C Production taxes are included in the RUS 500 series of accounts.

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2006

Summary

A	Total LOS and AVS Net Plant Investment	$	561,667,262	(ancillary worksheet 5)
B	Facilities with AGC (LOS 1 & AVS)	$	468,680,409	(Ancillary worksheet 5 less LOS 2)
C	B/A		83.4445%	
D	AGC Facilities	$	62,036	
E	AGC Facilities Percentage (D/B)		0.0132%	
F	Generation Revenue Requirement	$	216,619,915	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$	28,673	(E x F)
H	**Regulation Revenue Requirement**	**$**	**90,709**	(D + G)

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply and Voltage Control - 2006

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LOS #1	57,191	44.7590%	25,598	32,304	57,902
LOS #2	596,130	44.7590%	266,821	44,793	311,614
AVS #1	1,814,861	44.7590%	812,313	50,715	863,028
AVS #2	364,485	44.7590%	163,140	47,803	210,942
Spirit Mound (Units 1 & 2)	128,184	44.7590%	57,374	51	57,425
LRS - BEPC*	1,333,585	31.8468%	424,704	87,571	33,809
LRS - HCPD	112,994	90.3688%	102,111	5,366	107,477
Reactive Supply and Voltage Control Requirement					$ 1,642,198

*Costs prorated on east side capacity entitlement to total LRS plant capacity (0.065997).

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Allocation Factor - 2006

Ancillary
Worksheet 1

Allocation Factor for Reactive Power Support Portion of Generator Capacity

Unit	A Reactive Rating (MVAR)	B * Generator Rating (MVA)	E Alloc Factor A^2/(B^2+A^2)
LOS #1	148.00	240.00	0.275508
LOS #2	223.00	487.00	0.173333
Total LOS	371.00	727.00	0.206615
AVS #1	231.00	490.00	0.181833
AVS #2	231.00	491.00	0.181228
Total AVS	462.00	981.00	0.181530
Spirit Mound #1	33.00	52.00	0.287108
Spirit Mound #2	33.00	44.00	0.360000
Total SM	66.00	96.00	0.320955
LRS Unit #1	300.00	593.00	0.203782
	1,199.00	**2,397.00**	

*URGE ratings from 2003 case

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply And Voltage Control Allocation Factor - 2006

Ancillary
Worksheet 2

Allocation Factor for Reactive Power Support Portion of Exciter Capacity

	A	B	C	D	E	F	
Unit	Rated Exciter Current A	Maxium Current @Full Load (A)	Minimum Current @ Full Load (A)	AMPS Use Reactive Power Support (Max-Min)	(D/B) Use	Rated Voltage	Rated MW (a*f)/10^6
LOS #1	2,849	2,849	990	1,859	0.652510	375	1.0684
LOS #2	5,425	5,425	1,885	3,540	0.652535	430	2.3328
AVS #1	5,625	5,625	1,945	3,680	0.654222	400	2.2500
AVS #2	5,625	5,625	1,945	3,680	0.654222	400	2.2500
Spirit Mound #1							
Spirit Mound #2 (Avg)					0.653372		2.0541
LRS Unit #1	4,692	4,692	3,000	1,692	0.360614	505	2.3695
Total							**12.3247**

Basin Electric Power Cooperative
IS Ancillary Services
Generator Summary 2006

Generator Summary
Summer Peak Load
2006

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	88.1	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	88.1	200.0	-175.0
67110	LELAN41	G22.0	2	1	225.0	5.7	120.0	-90.0
67111	LELAN32	G20.0	2	1	475.0	-11.9	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	45.0	-15.0	30.0	-15.0
67117	SPIRIT72	G13.8	-2	0	45.0	-15.0	30.0	-15.0
67118	LARAM31	G24	2	1	593.5	98	310	-250.0
	TOTAL				**2343.5**	**310.4**	**1115.0**	**776.0**

Generator Summary
Winter Peak Load
2006

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	52.6	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	52.6	200.0	-175.0
67110	LELAN41	G22.0	2	1	151.0	-41.4	120.0	-90.0
67111	LELAN32	G20.0	-2	1	166.0	-56.0	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	0.0	0.0	0.0	0.0
67117	SPIRIT72	G13.8	-2	0	0.0	0.0	0.0	0.0
67118	LARAM31	G24	2	1	593.5	112.2	310	-250
	TOTAL				**1870.5**	**314.8**	**1055.0**	**746.0**

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power Costs - 2006

Ancillary
Worksheet 4

Real Power Allocation Ratio - Other Plant

$$\frac{\text{Exciter MW Requirements (worksheet 2)}}{\text{Generator MW Capacity (worksheet 1)}} \times \frac{\text{Generator MVAR @ Peak (worksheet 3)}}{\text{Generator MVAR Capability (worksheet 1)}} =$$

$$\frac{12.3247 \text{ MW}}{2{,}397.00 \text{ MW}} \times \frac{310.4 \text{ MVAR}}{1{,}199 \text{ MVAR}} =$$

0.1331%

Reactive Power Costs
Real Power Allocation Ratio - Fuel

$$\frac{\text{Exciter MW Requirements (worksheet 2)}}{\text{MWH generated}} \times \frac{\text{Generator MVAR @ Avg (worksheet 3)}}{\text{Generator MVAR Capability (worksheet 1)}} =$$

$$\frac{12.3247 \text{ MW}}{17{,}873{,}341 \text{ MWH}} \times \frac{312.6 \text{ MVAR}}{1{,}199 \text{ MVAR}} =$$

0.1575%

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power/Voltage Control

Generating Plant Costs
As of December 31, 2006
(Net Plant)

Line #	Description	LOS # 1	LOS #2	AVS #1	AVS #2	SM	LRS	Other	HCPD
1	Generating Plant (ACCT 310-348)	29,786,959	92,986,854	328,808,733	110,084,716	4,614,682	223,446,307	108,974,937	18,483,733
2	**Total Plant**	**$ 29,786,959**	**$ 92,986,854**	**$ 328,808,733**	**$ 110,084,716**	**$4,614,682**	**$ 223,446,307**	**$ 108,974,937**	**$ 18,483,733**
	Generators								
3	Total Plant	22,162	1,981,900	4,399,776	(leased)	269,348	2,579,141		268,888
4	Allocated to Reactive Power (Wkst 1)	27.5508%	17.3333%	18.1833%	18.1228%	32.0955%	20.3782%		20.3782%
5	Reactive Power Plant (L3*L4)	$ 6,106	$ 343,529	$ 800,026	$ -	$ 86,449	$ 525,582		$ 54,794
	Exciters								
6	Total Plant	16,803	69,491	476,968	(leased)	50,835	512,397		50,327
7	Allocated to Reactive Power (Wkst 2)	65.2510%	65.2535%	65.4222%	65.4222%	65.3372%	36.0614%		36.0614%
8	Reactive Power Plant (L6*L7)	$ 10,964	$ 45,345	$ 312,043	$ -	$ 33,214	$ 184,777		$ 18,149
	Voltage Regulators								
9	Total Plant	449	79,101	23,848	(leased)	2,542	77,374		8,067
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		100.0000%
11	Reactive Power Plant (L9*L10)	$ 449	$ 79,101	$ 23,848	$ -	$ 2,542	$ 77,374		$ 8,067
	Step-Up Transformers								
12	Total Plant	722	309,908	1,628,218	1,478,910	-	1,776,946		53,341
13	Allocated to Reactive Power (Wkst 6)	6.2500%	1.6162%	14.9306%	14.7569%	19.4444%	14.0580%		14.0580%
14	Reactive Power Plant (L12*L13)	$ 45	$ 5,009	$ 243,102	$ 218,242	$ -	$ 249,803		$ 7,499
	Other Plant								
15	Total Plant (L2-L5-L8-L11-L14)	29,769,395	92,513,869	327,429,714	109,866,474	4,492,478	222,408,772		18,395,225
16	Allocated to Reactive Power (Wkst 4)	0.1331%	0.1331%	0.1331%	0.1331%	0.1331%	0.1331%		0.1331%
17	Reactive Power Plant (L15*L16)	$ 39,626	$ 123,145	$ 435,842	$ 146,243	$ 5,980	$ 296,049		$ 24,486
	Total Reactive Power Plant								
18	(L5+L8+L11+L14+L17)	$ 57,191	$ 596,130	$ 1,814,861	$ 364,485	$ 128,184	$ 1,333,585		$ 112,994
	Fuel Expense								
19	Total	20,512,209	28,442,045	32,202,609	30,353,376	32,394	55,605,347		3,407,008
20	Allocated to Reactive Power (wkst 4)	0.1575%	0.1575%	0.1575%	0.1575%	0.1575%	0.1575%		0.1575%
21	Reactive Power Expense (L19*L20)	$ 32,304	$ 44,793	$ 50,715	$ 47,803	$ 51	$ 87,571		$ 5,366

Basin Electric Power Cooperative
IS Ancillary Services
Transformer Allocation
Reactive Power Costs

Ancillary
Worksheet 6

A	B	C	D
Plant	Transformer MVA *	Generator	Allocation Ratio (B-C/B)
AVS #1	576	490	0.149306
AVS #2	576	491	0.147569
LO #1	256	240	0.062500
LO #2	495	487	0.016162
SM #1	72	52	0.277778
SM #2	72	44	0.388889
LRS #3	690	593	0.140580

* Emergency Rating

Missouri River Energy Services
Ancillary Services
Cost Data

Generation Revenue Requirement — For the 12 months ended 12/31/06

EIA 412

Missouri River Energy Services/ Western Minnesota

	Production	LRS	WPP	Extra	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 44,979,348	$35,547,649	$2,077,977	$ 6,225,254	$ 444,196
Net Plant	$131,076,287	$67,308,615	$7,025,510	$ 53,500,283	$3,241,879
Percent of revenue requirement to net plant	34.32%	52.81%	29.58%	11.64%	13.70%

Generation Revenue Requirement
EIA 412
Missouri River Energy Services/ Western Minnesota

For the 12 months ended 12/31/06

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total		(4) Allocator	(5) Production	WMI LRS	WMI WPP
	GROSS PLANT IN SERVICE							
1	Production		247,980,516	DA	1.00000	247,980,516	170,866,128	17,834,593
2	Transmission		66,402,413	NA	0.00000	-		
3	Distribution		-	NA		-		
4	General		11,427,992	WS	0.78757	9,000,313	6,201,490	647,296
4a	Direct Assign - Transmission			NA		-		
4b	Direct Assign - Production			DA		-		
4c	Other			WS		-		
5	Intangible			NA		-		
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)		$ 325,810,921	GP	78.874%	256,980,829	177,067,618	18,481,889
	ACCUMULATED DEPRECIATION							
7	Production		122,820,705	DA	1.00000	122,820,705	107,070,626	11,175,773
8	Transmission		32,097,848	NA		-		
9	Distribution			NA		-		
10	General		3,915,648	WS	0.78757	3,083,836	2,688,376	280,606
10a	Direct Assign - Transmission			NA		-		
10b	Direct Assign - Production			DA		-		
10c	Other			WS		-		
11	Intangible			DA		-		
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)		$ 158,834,201			125,904,541	109,759,003	11,456,379
	NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	125,159,811	AUTO		125,159,811	63,795,502	6,658,820
14	Transmission	(line 2- line 8)	34,304,565	AUTO		-		
15	Distribution	(line 3 - line 9)	-	AUTO		-		
16	General	(line 4 - line 10)	7,512,344	AUTO		5,916,476	3,513,113	366,690
16a	Direct Assign	(line 4a - line 10a)	-	AUTO		-		
16b	Production	(line 4b - line 10b)	-	AUTO		-		
16c	Other	(line 4c - line 10c)	-	AUTO		-		
17	Intangible	(line 5 - line 11)	-	AUTO		-		
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)	12a.8.L5 less L2	$ 166,976,720	NP	78.500%	$ 131,076,287	67,308,615	7,025,510

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Generation Revenue Requirement — For the 12 months ended 12/31/06

EIA 412

Missouri River Energy Services/ Western Minnesota

No.	(1)	(2) Reference	(3) Company Total		(4) Allocator	(5) Production	WMMPA LRS	WPP
	O&M							
1	Production		14,896,888	DA	1.00000	14,896,888	13,946,528	260,021
2	A&G		6,908,628	WS	78.757%	5,441,009	5,093,895	94,971
3	Less Regulatory Fees			NA		-		
4	Production			NA				
5	Transmission			NA		-		
6	Headquarters			NA				
7	TOTAL O&M (sum lines 1 and 2)		$ 21,805,516			20,337,897	19,040,423	354,992
	DEBT SERVICE							
8	Debt Service- Excluding Transmission Bond Resolution		22,292,841	GP 2	85.757%	19,117,677	13,172,662	1,374,931
9	Debt Service- Transmission Bond Resolution		2,250,036	NA	0.000%	-	-	-
10	Amort of Debt Discount (428)			Excluded		-	-	-
11	Transmission			NA		-	-	-
12	Headquarters			WS			-	-
13	Production			DA			-	-
14	Other Deductions			NA		-	-	-
15	TOTAL DEBT SERVICE (Sum lines 8,9,10,14)		$ 24,542,877		77.895%	19,117,677	13,172,662	1,374,931
	TAXES OTHER THAN INCOME TAXES							
	LABOR RELATED							
	Payroll		-	WS		-		
16	Highway and vehicle		-	WS		-		
17	PLANT RELATED							
18	Property and Other Total			GP		-		
19	General Plant		60,089	W/S	78.757%	47,324	44,305	826
20	Gross Receipts Tax			NA		-		
21	Production (Note C)		636,949	DA	100.000%	636,949	438,877	45,809
22	TOTAL OTHER TAXES		$ 697,037			$ 684,273		
23	TOTAL OPERATING EXPENSES (Sum 7+15+22)		$ 47,045,431			40,139,847	32,213,085	1,729,923
24	Margin		$ 6,135,719	GP	78.874%	$4,839,501	3,334,563	348,054
25	REV. REQUIREMENT (sum lines 23 + 24)		$ 53,181,150		86.416%	$44,979,348	$ 35,547,649	$ 2,077,977

Line #	WAGES AND SALARY ALLOCATOR (W/S)				
(1)	(2)	(3) TOTAL	(4) Allocator	(5) Production	Production W/S Allocator
		$		Allocation	
1	Production	1,518,758	1.00	1,518,758	78.757%
2	Transmission	409,659	0.00	0	
3	Distribution	0	0.00	0	
4	Other	-		-	
5	Total (sum lines 18-21)	$ 1,928,417		$ 1,518,758	

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Supply and Voltage Control - 2006

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LRS - MRES/WMMPA	$ 380,748	52.8129%	201,084	28,731	229,815
Exira	$ 723,205	11.6359%	84,152	4,060	88,211
Watertown Power Plant	$ 178,811	29.5776%	52,888	409	53,297
					$ 371,323

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Allocation Factor - 2006

Ancillary

Worksheet 1

Allocation Factor for Reactive Power Support Portion of Generator Capacity

Unit	A Reactive Rating (MVAR)	B * Generator Rating (MVA)	E Alloc Factor A^2/(B^2+A^2)
LRS Unit #1**	300.00	593.00	0.203782
WPP	33.00	52.00	0.287108
Exira 1	38.00	46.00	0.405618
Exira 2	38.00	47.00	0.395292
Total Exira	76.00	93.00	0.400416

** = Used Basin %.

Missouri River Energy Services/ Western Minnesota

Ancillary

Worksheet 2

IS Ancillary Services

Reactive Supply And Voltage Control Allocation Factor - 2006

Allocation Factor for Reactive Power Support Portion of Exciter Capacity

	A	B	C	D	E	F	
Unit	Rated Exciter Current A	Maxium Current @Full Load (A)	Minimum Current @ Full Load (A)	AMPS Use Reactive Power Support (Max-Min)	(D/B) Use	Rated Voltage	Rated MW (a*f)/10^6
WPP **	3,138	3,138		3,138	0.653372	330	0.10355
Exira 1	2,977	2,977		2,977	0.506993	185	0.05507
Exira 2	2,977	2,977		2,977	0.506993	185	0.05507
Total Exira *	5,954	5,954		5,954	0.506993	370	0.22030
LRS Unit #1**	4,692	4,692	3,000	1,692	0.360614	505	2.3695
Total					0.5070		2.8035

* = Average of WPP & LRS.

** = Used Basin %.

Missouri River Energy Services/ Western Minnesota
IS Ancillary Services
Reactive Power/Voltage Control

Ancillary
Worksheet 5

Generating Plant Costs
As of December 31, 2006
(Net Plant)

		Basin	MRES/WMMPA				
Line #	Description	LRS	LRS *	WPP	Exira	Other	Total Gen.
1	Net Generating Plant (ACCT 310-348)	223,446,307	$ 63,795,502	$ 6,658,820	$ 51,581,739	$ 3,123,750	$ 125,159,811
2	**Total Plant**	$ 223,446,307	$ 63,795,502	$ 6,658,820	$ 51,581,739	$ 3,123,750	$ 125,159,811
	Generators						
3	Total Plant	2,579,141	736,363	388,660	1,289,543		
4	Allocated to Reactive Power (Wkst 1)	20.3782%	20.3782%	28.7108%	40.0416%		
5	Reactive Power Plant (L3*L4)	$ 525,582	$ 150,057	$ 111,587	$ 516,354	$ -	$ 777,998
	Exciters						
6	Total Plant	512,397	146,293	73,353	154,745		
7	Allocated to Reactive Power (Wkst 2)	36.0614%	36.0614%	65.3372%	50.6993%		
8	Reactive Power Plant (L6*L7)	$ 184,777	$ 52,755	$ 47,927	$ 78,455	$ -	$ 179,137
	Voltage Regulators						
9	Total Plant	77,374	22,091	3,668	25,791		
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
11	Reactive Power Plant (L9*L10)	$ 77,374	$ 22,091	$ 3,668	$ 25,791	$ -	$ 51,549
	Step-Up Transformers						
12	Total Plant	1,776,946	507,331	19,976	154,745		
13	Allocated to Reactive Power (Wkst 6)	14.0580%	14.0580%	35.0000%	22.5000%		
14	Reactive Power Plant (L12*L13)	$ 249,803	$ 71,320	$ 6,992	$ 34,818	$ -	$ 113,130
	Other Plant						
15	Total Plant (L2-L5-L8-L11-L14)	222,408,772	63,499,278	6,488,647	50,926,322	3,123,750	
16	Allocated to Reactive Power*	0.1331%	0.1331%	0.1331%	0.1331%		
17	Reactive Power Plant (L15*L16)	$ 296,049	$ 84,524	$ 8,637	$ 67,788	$ -	$ 160,949
	Total Reactive Power Plant						
18	(L5+L8+L11+L14+L17)	$ 1,333,585	$ 380,748	$ 178,811	$ 723,205	$ -	$ 1,282,764
	Fuel Expense						
19	Total	55,605,347	18,243,245	259,539	2,577,855	0	
20	Allocated to Reactive Power*	0.1575%	0.1575%	0.1575%	0.1575%	0.1575%	
21	Reactive Power Expense (L19*L20)	$ 87,571	$ 28,731	$ 409	$ 4,060	$ -	$ 33,199

* = Used BEPC %.

Missouri River Energy Services/ West

IS Ancillary Services

Transformer Allocation

Reactive Power Costs

Ancillary

Worksheet 6

A	B	C	D
Plant	Transformer MVA *	Generator	Allocation Ratio (B-C/B)
LRS **	690	593	0.140580
WPP	80	52	0.35000
Exira 1	60	46	0.2333333
Exira 2	60	47	0.2166667
Total Exira	120	93	0.2250000

** = Used Basin %.

* Emergency Rating

Heartland's Transmission Cost Data

HEARTLAND CONSUMERS POWER DISTRICT
INTEGRATED SYSTEM TARIFF - EAST SIDE
December 31, 2006

9-Mar-07

Line	Description	Cost of Service Amount	
1.	Transmission Plant Investment **	$1,292,610.66	Page 4, Line L66,L69
2.	Less Accumulated Depreciation & IDC **	($124,783.56)	Page 4, Lines M66,69,N66,69
3.	General Plant - Trans Share	$29,849.85	Page 4, Line L80
4.	Less Accum Depre & IDC-GP-Trans	($13,529.20)	Page 4, Lines M80,N80
5.	Materials & Supplies - Trans	$0.00	Page 2
6.	Cash Working Capital	$3,142.59	1/12 of Line 16 + 17 (this page)
7.	**Transmission Investment Rate Base**	**$1,187,290.35**	
8.			
9.	Rate of Return * 6.95%	$82,516.68	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense **	$7,656.47	Page 4, Line P66,P69
11.	GP Depr Expense - Trans Share	$880.35	Page 4, Line P80
12.	GP Maintenance	$1,128.73	Page 1, Line C41
13.	Income Tax	$50.54	Page 1, Line C47
14.	Taxes Other than Income	$11,352.05	Page 1, Lines C51,C53,C55,C56
15.	A & G Expenses	$62,429.76	Page 2, Line C65
16.	Transmission O & M	$37,711.09	Page 2, Line C71,C72,C74
17.	Less:Trans of Elect by Others	$0.00	Page 2, Line C83
18.	**Subtotal Transmission Revenue Requirement**	**$203,725.68**	
19.			
20.	Annual Trans Third Party Payment	$0.00	
21.	Annual Trans Third Party Revenue	$14,599.01	Revenues from MAPP Schedule F
22.			
23.	**Total Transmission Revenue Requirement**	**$189,126.67**	

* Weighted Cost of Capital
** Doesn't Include HCPD's TP-II Investment

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE) k:\data\accounting\transm06

December 31, 2006 9-Mar-07

	HCPD Invest	East Side	Depr	IDC	West Side	Depr	IDC
LRS	$49,457,848.65	$3,503,486.68	29.28%	29.24%	$3,957,170.33	100.00%	100.00%
TP-I	$907,635.18	$907,635.18	7.58%	7.58%		0.00%	0.00%
TP-II	$6,752,305.09	$6,752,305.09	56.43%	56.36%		0.00%	0.00%
TP-II Marshall	$402,535.87	$402,535.87	3.36%	3.36%		0.00%	0.00%
TP-III Groton	$384,975.48	$384,975.48	3.22%	3.21%		0.00%	0.00%
	$57,905,300.27	$11,950,938.30			$3,957,170.33		
		2.53%			*7.56%*		
General Plant Improvement	$617,234.18	$15,597.20	0.13%	0.13%	$0.00	0.00%	0.00%
Furniture & Equipment	$128,606.49	$3,249.82		0.03%	$0.00		0.00%
Furniture & Equipment-EPD	$325,113.36	$8,215.45		0.07%	$0.00		0.00%
Transportation Equipment	$55,329.26	$1,398.14		0.01%	$0.00		0.00%
Headquarter's Improvement	$54,976.84	$1,389.24		0.01%	$0.00		0.00%
	$59,086,560.40	$11,980,788.15	100.00%	100.00%	$3,957,170.33	100.00%	100.00%

	Depreciation	East Side	West Side
Accum Depr-Plant	$31,705,281.03	$801,176.63	$2,397,343.70
Accum Depr-Gen'l Plant	$418,879.79	$10,584.88	$0.00
Accum Depr-Trans Equip	$40,244.87	$1,016.97	$0.00
	$32,164,405.69	$812,778.48	$2,397,343.70

	Int During Const	East Side	West Side
1977 IDC	$29,680,964.00		
1979 IDC	$28,763,565.00		
Times 24%	$14,026,687.00	$354,447.38	$1,060,605.32

	Annual Depr	East Side	West Side
Depr Exp-Plant	$2,805,000.00	$70,880.95	$212,095.55
Depr Exp-Gen'l Plant	$21,785.18	$550.50	$0.00
Depr Exp-Trans Equip	$9,397.18	$237.46	$0.00
	$2,836,182.36	$71,668.91	$212,095.55

	GP Maint	East Side	West Side
HCPD	$44,667.84	$1,128.73	$0.00
LRS	$0.00	$0.00	$0.00
	$44,667.84	$1,128.73	$0.00

	Income Tax	East Side	West Side
	$2,000.00	$50.54	$0.00

	Tax Other Than Income	East Side	West Side
HCPD Payroll	$65,044.98	$1,643.65	$0.00
LRS Payroll	$0.00	$0.00	$0.00
Headquarter's	$12,285.74	$310.45	$0.00
LRS (HCPD)	$186,491.45	$4,712.55	$14,101.25
TP-I	$6,308.04	$6,308.04	$0.00
TP-III	$3,089.91	$3,089.91	$0.00
TP-II	$55,143.44	$0.00	$0.00
	$328,363.56	$16,064.60	$14,101.25

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)
December 31, 2006

	A&G Expenses	East Side	West Side
HCPD	$2,470,557.84	$62,429.76	$0.00
LRS-Trans	$145,397.27	$109,047.95	$36,349.32
	$2,615,955.11	$171,477.72	$36,349.32

	Transm O&M	East Side	West Side
TP-I	$31,115.17	$31,115.17	$0.00
TP-III Groton	$6,595.92	$6,595.92	$0.00
LRS-Trans	$195,171.15	$146,378.36	$48,792.79
	$232,882.24	$184,089.45	$48,792.79

*** Not Included in Transm O&M and Trsm by Others:*

Network Transm Service Charge	*$1,865,007.06*
Ancillary Services	*$51,606.54*
MISO	*$320,744.64*

	Trsm by Others	East Side	West Side
LRS-Trans	($61,632.36)	($46,224.27)	($15,408.09)
	($61,632.36)	($46,224.27)	($15,408.09)

	Material & Supplies	East Side	West Side
REA Acct 163 Balance Sheet Items	$0.00	$0.00	$0.00

Rate of Return

2006 Liability	$53,174,916.19	91.95%	6.42%	5.90%
2006 Net Assets	$4,652,660.66	8.05%	13.00%	1.05%
	$57,827,576.85			6.95%

Equity @ 13% based on risk from:

- Contractual commitment
- Magnitude of surplus power
- Competition
- Comparable Utilities @ 12%
- Phone Conversations with Auditors

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE) 9-Mar-07

December 31, 2006

CPX	Description	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
	LINES					
049	345 kV Line from LRS to NB Border (50%)	$170,416.26				
050	345 kV Line NB Border to Stegall Sub (50%)	$14,968.31				
051	345 Line From LRS to NB Border	$137,815.17				
052	345 kV Line From NB Border to Sidney Sub	$213,292.60				
053	345 kV Line from Stegall Sub to Sidney Sub	$286,411.91				
074	345 kV Line From LRS to CO Border (.10457)	$112,442.49				
077	LRS PlantSite Lines (.42786)	$31,082.68				
091	Nebraska Tax	$11,492.90				
101	230 kV Line From Sidney Sub to WAPA Sub	$28,871.31				
103	230 kV Line Stegall Sub to Stegall/WAPA	$18,007.22				
	Subtotal Lines	***$1,024,800.85***				
	SUBSTATIONS					
048	345 kV LRS Substation (.42786)	$150,298.69				
078	345/230 kV Stegall Substation	$177,680.30				
079	345/230 kV Sidney Substation	$241,006.03				
084	230 kV Stegall-WAPA Sub Addition	$35,271.55				
054	230/345 kV Trsn Facilities-NPPD (Intang Plant)	$1,633,730.01				
100	230/115 kV Sidney Substation Addition	$17,550.88				
116	LRS #1 Main Transformer (.87766)	$95,876.46				
	Subtotal Substations	***$2,351,413.92***				
	MICROWAVE COMMUNICATIONS					
131	Microwave-Wyoming (50%)	$38,491.66				
133	Microwave-Nebraska	$41,313.81				
135	Microwave-North Dakota	$340.92				
138	Microwave-South Dakota	$3,124.90				
		$83,271.29				
	Less Microwave Non-Transmission (70%)	$58,289.90				
	Subtotal Microwave Communications	***$24,981.39***				
	MAINTENANCE BUILDINGS					
107	Maintenance Building-Stegall	$73,101.40				
108	Maintenance Building-LRS (50%)	$29,189.12				
	Subtotal Maintenance Buildings	***$102,290.52***				
	Total LRS Transmission-East Side	***$3,376,214.77***	$226,042.39	$99,884.12	$3,050,288.26	$19,998.21
	Total LRS General Plant-East Side	***$127,271.91***	$8,521.04	$3,765.29	$114,985.57	$753.87
	Total LRS-East Side	***$3,503,486.68***	***$234,563.43***	***$103,649.41***	***$3,165,273.83***	***$20,752.08***

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE)
December 31, 2006
Page 4 of 6

	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
HEARTLAND TRANSMISSION					
TP-I Irv Simmons	$907,635.18	$60,767.47	$26,852.07	$820,015.64	$5,376.16
TP-II	$6,752,305.09	$452,076.46	$199,764.56	$6,100,464.07	$39,995.69
TP-II Marshall	$402,535.87	$26,950.35	$11,908.88	$363,676.64	$2,384.33
TP-III Groton Sub	$384,975.48	$25,774.66	$11,389.36	$347,811.46	$2,280.31
Total HCPD Transmission-East Side	*$8,447,451.62*	*$565,568.94*	*$249,914.87*	*$7,631,967.81*	*$50,036.49*
HEARTLAND GENERAL PLANT					
General Plant Improvement	$15,597.20	$1,044.25	$461.44		$92.39
Furniture & Equipment	$3,249.82	$10,584.88	$96.14		$550.50
Furniture & Equipment-EPD	$8,215.45		$243.05		
Transportation Equipment	$1,398.14	$1,016.97	$41.36		$237.46
Headquarter's Improvement	$1,389.24		$41.10		
Total HCPD General Plant-East Side	*$29,849.85*	*$12,646.10*	*$883.10*	*$16,320.65*	*$880.35*
TOTAL EAST SIDE TRANSMISSION & GENERAL PLANT	*$11,980,788.15*	*$812,778.47*	*$354,447.38*	*$10,813,562.30*	*$71,668.91*

HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE) 9-Mar-07

December 31, 2006

CPX	Description	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
	LINES					
049	345 kV Line from LRS -Stegall (50%)	$170,416.26				
050	345 kV Line from LRS-Stegall Sub (50%)	$14,968.31				
073	230 kV Line From LRS to D Johnston	$163,808.79				
074	345 kV Line From LRS-Story (.104569)	$962,841.92				
075	345 kV Line from CO Border to Story Sub	$969,899.69				
077	LRS PlantSite Lines (.57214)	$41,564.16				
102	230 kV Stegall Tie Line	$20,461.61				
104	345 kV Line- to CO Border	$552,803.72				
105	345 kV Line -CO Border to Ault	$176,226.00				
106	230 kV Sidney Tie Line	$15,568.45				
	Subtotal Lines	*$3,088,558.91*				
	SUBSTATIONS					
045	230 kV LRS Switch Station (4 Terminals)	$132,912.22				
048	345 kV LRS Substation (5 of 8 Trmls)(.57214)	$200,981.37				
076	230 kV D Johnston Substation	$22,510.81				
085	345 kV Ault Substation	$143,063.70				
086	230 kV Story Substation	$24,621.21				
116	LRS #1 Main Transformer (.12234)	$13,364.54				
117	LRS #2 Main Transformer	$54,608.46				
118	LRS #3 Main Transformer	$61,728.02				
190	345 kV Story Substation	$168,160.13				
	Subtotal Substations	*$821,950.46*				
	MICROWAVE COMMUNICATIONS					
131	Microwave-Wyoming (50%)	$38,491.66				
132	Microwave-Colorado	$19,747.79				
		$58,239.45				
	Less Microwave Non-Transmission (70%)	$40,767.62				
	Subtotal Microwave Communications	*$17,471.84*				
	MAINTENANCE BUILDINGS					
108	Maintenance Building-LRS (50%)	$29,189.12				
	Subtotal Maintenance Buildings	*$29,189.12*				
	Total LRS Transmission-West Side	*$3,910,509.37*	$2,369,075.43	$1,048,099.20	$493,334.74	$209,594.63
	Total LRS General Plant-West Side	*$46,660.96*	$28,268.27	$12,506.12	$5,886.57	$2,500.92
	Total LRS-West Side	*$3,957,170.33*	*$2,397,343.70*	*$1,060,605.32*	*$499,221.31*	*$212,095.55*

HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)
December 31, 2006

	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
HEARTLAND TRANSMISSION					
TP-I Irv Simmons	$0.00	$0.00	$0.00	$0.00	$0.00
TP-II	$0.00	$0.00	$0.00	$0.00	$0.00
TP-II Marshall	$0.00	$0.00	$0.00	$0.00	$0.00
TP-III Groton Sub	$0.00	$0.00	$0.00	$0.00	$0.00
Total HCPD Transmission-West Side	*$0.00*	*$0.00*	*$0.00*	*$0.00*	*$0.00*
HEARTLAND GENERAL PLANT					
General Plant Improvement	$0.00	$0.00	$0.00		$0.00
Furniture & Equipment	$0.00	$0.00	$0.00		$0.00
Furniture & Equipment-EPD	$0.00		$0.00		
Transportation Equipment	$0.00	$0.00	$0.00		$0.00
Headquarter's Improvement	$0.00		$0.00		
Total HCPD General Plant-West Side	*$0.00*	*$0.00*	*$0.00*	*$0.00*	*$0.00*
TOTAL WEST SIDE TRANSMISSION & GENERAL PLANT	***$3,957,170.33***	***$2,397,343.70***	***$1,060,605.32***	***$499,221.31***	***$212,095.55***

Transmission Customer Facility Credits

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/06

Missouri River Energy Services

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ 11,783,346
	REVENUE CREDITS	(Note Q)				
2	Account No. 454	(page 3, line 34)	0	TP	1.00000	0
3	Account No. 456	(page 3, line 37)	28,875	TP	1.00000	28,875
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					28,875
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 11,754,470

Allocation of Net Revenue Requirements by Pricing Zones:

	Irv Simmons	OTP	MBPP	Total
Transmission Plant Investment	$ 1,957,786	$ 26,149,371	$ 38,295,256	$ 66,402,413
% of Total Transmission Plant	2.95%	39.38%	57.67%	100.0%
Net Transmission Revenue Requirement (Allocated on Transmission Plant)	$ 346,565	$ 4,628,928	$ 6,778,977	$ 11,754,470

Line No.			
	DIVISOR		
8	Average of 12 coincident system peaks for requirements (RQ) service	(Note A)	594,391
9	Plus 12 CP of firm bundled sales over one year not in line 8	(Note B)	0
10	Plus 12 CP of Network Load not in line 8	(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)	(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year		0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative)	(Note P)	0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)		0
15	Divisor (sum lines 8-14)		594,391

Line No.			Peak Rate		Off-Peak Rate
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ 19.776		
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	$ 1.648		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.380		$0.380
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.076	Capped at weekly rate	$0.054
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	4.754	Capped at weekly and daily rates	$2.264
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
			$0.000	Long Term	$0.000 Long Term
22					

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/06

Missouri River Energy Services

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.11.d	14,542,451	TE	1.0000	14,542,451
1a	Less LSE Expenses included in Transmission O&M Accounts (I		0			
2	Less Account 565		11,418,024	TE	1.0000	11,418,024
3	A&G	VII.16.d	6,908,628	W/S	0.2124	1,467,619
4	Less FERC Annual Fees		0	W/S	0.2124	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		0	W/S	0.2124	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		0	TE	1.0000	0
6	Common		0	CE	0.2124	0
7	Transmission Lease Payments		0	TE	1.0000	0
8	TOTAL O&M (sum lines 1, 1a, 3, 5a, 6, 7 less 2, 4, 5)		10,033,055			4,592,046
	DEBT SERVICE (Note S)					
9	Debt Service- Excluding Transmission Bond Resolution		22,292,841	GP 2	0.1424	3,175,164
9	Debt Service- Transmission Bond Resolution		2,250,036	DA	1.0000	2,250,036
10	Amortization of premium or discount		0	GP	0.2113	0
12	TOTAL DEBT SERVICE (Sum lines 9 - 10)		24,542,877			5,425,200
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.2124	0
14	Highway and vehicle		0	W/S	0.2124	0
15	PLANT RELATED					
16	Property- Transmission Only		457,117	DA	1.0000	457,117
16	Property- General Plant		60,089	W/S	0.2124	12,765
17	Gross Receipts		0	GP	0.2113	0
18	Other		0	DA	1.0000	0
19	Payments in lieu of taxes		0	GP	0.2113	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		517,205			469,881
21	SUBTOTAL (sum lines 8, 12 and 20)		35,093,137			10,487,127
22	MARGIN REQUIREMENT (Note H)		6,135,719	GP	0.2113	1,296,218
23	REV. REQUIREMENT (sum lines 21- 22)		41,228,857			11,783,346

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/06

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.		EIA 412 Reference	Company Total	Allocator		Transmission
	GROSS PLANT IN SERVICE					
1	Production	IV.6.f	247,980,516	NA	0.0000	0
2	Transmission	IV.7.f	66,402,413	TP	1.0000	66,402,413
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	11,427,992	W/S	0.2124	2,427,679
5	Common		0	CE	0.2124	0
6	TOTAL GROSS PLANT (sum lines 1-5)		325,810,921	GP	0.2113	68,830,092
6	Gross Plant, excluding facilities financed under the Transmission Bond Resolution (Note T)		299,661,550	GP 2	0.1424	42,680,721

TRANSMISSION PLANT INCLUDED IN ISO RATES

Line No.			
7	Total transmission plant (line 2)		66,402,413
8	Less transmission plant excluded from ISO rates (Note J)		0
9	Less transmission plant included in OATT Ancillary Services (Note K)		0
10	Transmission plant included in ISO rates (line 7 less lines 8 & 9)		66,402,413
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)	TP=	1.00000

TRANSMISSION EXPENSES

Line No.			
12	Total transmission expenses (page 2, line 1, column 3)		14,542,451
13	Less transmission expenses included in OATT Ancillary Services (Note I)		0
14	Included transmission expenses (line 12 less line 13)		14,542,451
15	Percentage of transmission expenses after adjustment (line 14 divided by line 12)		1.00000
16	Percentage of transmission plant included in ISO Rates (line 11)	TP	1.00000
17	Percentage of transmission expenses included in ISO Rates (line 15 times line 16)	TE=	1.00000

WAGES & SALARY ALLOCATOR (W&S) (Note L)

Line No.		$		Allocation		W&S Allocator ($ / Allocation)
18	Production	1,518,758	0.00	0		
19	Transmission	409,659	1.00	409,659		
20	Distribution	0	0.00	0		
21	Other	0		0		
22	Total (sum lines 18-21)	1,928,417		409,659	=	0.2124

COMMON PLANT ALLOCATOR (CE) (Note M)

Line No.		$	% Electric (line 23 / line 26)		Labor Ratio (line 22)		CE
23	Electric	325,810,921					
24	Gas	0	1.00000	*	0.2124	=	0.2124
25	Water	0					
26	Total (sum lines 23-25)	325,810,921					

FINANCING DATA

Line No.			$
27	Long Term Debt	I.33.b +34.b	$247,277,372
28	Debt Service		24,542,877
29	Interest on Long Term Debt	II.16.b + II.17.b Note R	11,127,877
30	Bond Principal Amortization (line 28 less line 29)		13,415,000

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
31	a. Bundled Non-RQ Sales for Resale	(Note N)	
32	b. Bundled Sales for Resale included in Divisor on page 1		
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)		
35	a. Transmission charges for all transmission transactions (Schedule F Revenues)		$28,875
36	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
37	Total of (a)-(b)		$28,875

Itilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 3,104,020
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 454	(page 4, line 34)	0	TP	0.77563	0
3	Account No. 456	(page 4, line 37)	106,053	TP	0.77563	82,258
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.77563	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.77563	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					82,258
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 3,021,763
						$0.4078
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		216,919
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		14,000
10	Plus 12 CP of Network Load not in line 8			(Note C)		0
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					230,919
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	13.086			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	1.090			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.252			$0.252
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.050	Capped at weekly rate		$0.036
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.146	Capped at weekly and daily rates		$1.498
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term
22			$0.000	Long Term		$0.000 Long Term

Itilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	Amount related to Exclusions	
	GROSS PLANT IN SERVICE							
1	Production	206.42.g	147,877,434	NA				
2	Transmission	206.53.g	29,894,838	TP	0.77563	23,187,367		
3	Distribution	206.69.g	179,592,574	NA				
4	General & Intangible	206.5.g & 83.g	7,908,661	W/S	0.04351	344,079		
5	Common	356.1	32,115,282	CE	0.02639	847,639		
6	TOTAL GROSS PLANT (sum lines 1-5)		397,388,788	GP=	6.135%	24,379,085		
	ACCUMULATED DEPRECIATION							Accumulated Depreciation of Joint Pl. Transmission Facilities
7	Production	219.18-22.c	91,230,506	NA				
8	Transmission	219.23.c	21,051,111	VEst.	74.946%	15,776,883		5,274,226
9	Distribution	219.24.c	66,193,530	NA				
10	General & Intangible	219.25.c	2,449,157	W/S	0.04351	106,555		
11	Common	356.1	10,265,533	CE	0.02639	270,945		
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		191,195,836			16,154,382		
	NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	56,640,928					
14	Transmission	(line 2- line 8)	8,843,728			7,410,484		
15	Distribution	(line 3 - line 9)	113,399,044					
16	General & Intangible	(line 4 - line 10)	5,459,504			237,525		
17	Common	(line 5 - line 11)	21,849,749			576,694		
18	TOTAL NET PLANT (sum lines 13-17)		206,192,952	NP=	3.989%	8,224,703		
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negativ	273.8.k	0	NA	zero	0		Accumulated Deferred Income Taxes
20	Account No. 282 (enter negativ	275.2.k	0	VEst.	0.06446	597,239	597,239	Accumulated Deferred Income Taxes
21	Account No. 283 (enter negativ	277.9.k	-245,720,347	NP	0.03989	-9,801,386		Accumulated Deferred Income Taxes
22	Account No. 190	234.8.c	247,975,401	NP	0.03989	9,891,337		Accumulated Deferred Income Taxes
23	Account No. 255 (enter negativ	267.8.h	-4,504,569	VEst.	0.06446	-158,990	135,242	Accumulated Deferred Investment Ta
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-2,309,515			528,200		
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.74946	0		
	WORKING CAPITAL (Note H)							
26	CWC	calculated	1,140,063			80,289		
27	Materials & Supplies (Note G)	227.6.c & .15.c	1,434		1.00000	1,434	Excluded transmission maintained and supplied by others	
28	Prepayments (Account 165)	111.46.d	3,850,587	GP	0.06135	236,227		
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		4,992,084			317,949		
30	RATE BASE (sum lines 18, 24, 25, & 29)		208,875,521			9,070,851		

Utilizing FERC Form 1 Data

Itilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	O&M							
1	Transmission	321.100.b	5,948,883	TE	0.77563	5,828,623		Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	5,412,891		1.00000	5,412,891		
3	A&G	323.168.b	8,584,511	W/S	0.02639	226,576		
4	Less FERC Annual Fees		0	W/S	0.02639	0		
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		0	W/S	0.02639	0		
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.77563	0		
6	Common	356.1	0	CE	0.02639	0		
7	Transmission Lease Payments		0		1.00000	0		
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		9,120,503			642,309		
	DEPRECIATION EXPENSE						Excluded	
9	Transmission	336.7.b	900,067	VRB0(	0.74946	699,500	200,567	
10	General	336.9.b	357,870	W/S	0.02639	9,445		
11	Common	336.10.b	2,228,622	CE	0.02639	58,769		
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		3,484,559			767,714		
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	262.i	1,715,505	W/S	0.02639	45,278		
14	Highway and vehicle	262.i	0	W/S	0.02639	0		
15	PLANT RELATED							
16	Property	262.i	5,529,875	GP	0.06135	339,248		
17	Gross Receipts	262.i	224,433	NA	zero	0		
18	Other	262.i	341,008	GP	0.06135	20,920		
19	Payments in lieu of taxes		0	GP	0.06135	0		
20	TOTAL OTHER TAXES (sum lines 13 - 19)		7,810,821			405,446		
	INCOME TAXES	(Note K)						
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%					
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		45.92%					
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from line 21)		1.5385					
24	Amortized Investment Tax Credit (266.8f) (enter negative)		534,881					
25	Income Tax Calculation = line 22 * line 28		9,466,035	NA		411,082		
26	ITC adjustment (line 23 * line 24)		822,894	NP	0.03989	17,758	From detail on VRBase00I w/ exclusions	
27	Total Income Taxes	(line 25 plus line 26)	10,288,929			393,324		
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		20,614,480	NA		895,226		
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		51,319,293			3,104,020		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/05

Itilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES			
1	Total transmission plant (page 2, line 2, column 3)		29,894,838	Transmission Plant Grandfathered wi Joint Plants from VRB00I 6,707,471
2	Less transmission plant excluded from ISO rates (Note M)		6,707,471	
3	Less transmission plant included in OATT Ancillary Services (Note N)		0	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		23,187,367	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.77563	
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)		5,948,883	
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0	
8	Included transmission expenses (line 6 less line 7)		5,948,883	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000	
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.77563	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.77563	

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.18.b	433,136	0.00	0				
13	Transmission	354.19.b	253,718	0.78	196,792				
14	Distribution	354.20.b	3,386,124	0.00	0				
15	Other	354.21,22,23.b	1,758,732	0.00	0				
16	Total (sum lines 12-15)		5,831,709		196,792	=	0.03375	= WS	Wages & salaries by others
							0.04351	= Wsact	for excluded facilities MEC, OTP, MDU

COMMON PLANT ALLOCATOR (CE) (Note O)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	305,273,507	0.78215	*	0.03375	=	0.02639
18	Gas	200.3.d	161,740,399					
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		467,013,905					

RETURN (R)

Line			$
21		Long Term Interest (117, sum of 56c through 60c)	$13,692,212
22		Preferred Dividends (118.29c) (positive number)	$

	Development of Common Stock:				
23	Proprietary Capital (112.14d)				676,337,840
24	Less Preferred Stock (line 28)				0
25	Less Account 216.1 (112.12d) (enter negative)				44,734,006
26	Common Stock (sum lines 23-25)				721,071,846

		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 16d through 19d)	221,350,000	23%	0.0619	0.0145	=WCLTD
28	Preferred Stock (112.3d)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	721,071,846	77%	0.1100	0.0842	
30	Total (sum lines 27-29)	942,421,846			0.0987	=R

REVENUE CREDITS

				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			213,211
32	b. Bundled Sales for Resale included in Divisor on page 1			213,211
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$222,102
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$116,049
37	Total of (a)-(b)			$106,053

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/05

Utilizing FERC Form 1 Data With 7-Factor Changes-EXCLUDES EXT. Joint Plant Transmission Faciliti

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.

C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.