Department of Energy
Western Area Power Administration
Watertown Operations Office
P.O. Box 790
1330 41st Street SE
Watertown, South Dakota 57201-0790

April 14, 2009

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, 2009. 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 $ 155,395,038.
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $3.06/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 4.19 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$44.59/schedule/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.09/kWmonth
Regulation and Frequency Response	UGP-AS3	$0.05/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, 2009, is 4 percent and unchanged from the previous 3-year period. The new rate shall be used in transmission bills issued on or after June 1, 2009.

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

Sincerely,

Lloyd A. Linke
Operations 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, 2009

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective May 1, 2009

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
2008

Line No.			
1			
2			
3	Annual IS Transmission Costs		Notes
4	Basin Electric	$42,558,631	Basin Electric Revenue Requirement Worksheet
5	Western	$108,992,848	Western Annual IS Transmission Costs Worksheet, L69
6	Heartland	$1,029,817	Heartland IS Tariff Worksheet
7		$152,581,296	L4 + L5 + L6
8			
9			
10	Transmission Customer Facility Credits		
11		$368,898	MRES Irv Simmons Revenue Requirement Worksheet
12		$5,474,190	MRES MBPP from Revenue Requirement Worksheet
13		$2,698,136	NWPS Revenue Requirement Worksheet
14		$8,541,224	
15			
16	Transmission Revenue Requirement Adjustment		
17		($547,080)	Basin Electric
18		($150,492)	Western Area Power Administration
19		$173,922	Heartland
20		($523,650)	
21			
22	Transmission Revenue Credits		
23			
24	Short-Term Firm Point-to-Point Transmission Service Credit		
25		($8,523)	
26			
27	Non-Firm Point-to-Point Transmission Service Credit		
28		($145,017)	
29			
30	Revenue from Existing Transmission Agreements		
31		($4,526,875)	
32			
33	Scheduling, System Control and Dispatch Service Credit		
34		($523,417)	
35			
36			
37	Annual Revenue Requirement for IS Transmission Service		
38			
39		$155,395,038	L7 + L14 + L20 + L25 + L28 + L31 + L34

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
2008

Line No.			Notes
1			
2			
3	Annual Revenue Requirement for IS Transmission Service		Notes
4			
5		$155,395,038	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	IS Transmission System Total Load		
9			
10		4,237,000 KW	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo		
14			
15		**$3.06 / KW-Mo**	L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
2008

Line No.			Notes
1			
2			
3	Firm Point-to-Point Transmission Rate in $/KW-Mo		
4			
5		$3.06 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	Maximum Non-Firm Point-to-Point Transmission Rate		
10		**4.19 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2008

A.	Fixed Charge Rate	23.236%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$15,704,308	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,649,053	(A x B)
D.	FY 2008 Number of Daily Schedules	81,831	
E.	Rate for Scheduling, System Control and Dispatch Service ($/schedule/day)	**$44.59**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2008.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (38.41%) and communication facilities plant (67.21%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2008 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 2008 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,376,635	(1)
B.	BEPC & HCPD Reactive Service Revenue Requirement	$1,779,550	(2)
C.	MRES Reactive Service Revenue Requirement	$340,313	(3)
D.	Total Reactive Revenue Requirement	$4,496,498	(A+B+C)
E.	2008 IS Transmission System Total Load (kW-Yr)	4,237,000	(4)
F.	Annual Reactive Charge ($/kW-Yr)	$1.06	(D/E)
G.	Monthly Reactive Charge ($/kW-Mo)	$0.09	(F/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2008, 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 2008

A.	Fixed Charge Rate	16.508%	(1)	
B.	Generation Net Plant Costs	$ 475,144,224	(2)	
C.	Annual Cost of Generation	$ 78,436,808	(A x B)	
D.	Plant Capacity (kW)	2,364,000		
E.	Cost/kW ($/kW)	$ 33.18	(C / D)	
F.	Monthly Charge ($/kW-mo)	$ 2.77	(E / 12 months)	
G.	Western's Load (kW-Yr)	1,549,083	(3)	
H.	Capacity used for Reserves (kW)	77,454	(Gx5%)	(4)
I.	Annual Reserves Revenue Requirement	$ 2,569,924	(E x H)	
J.	Annual Charge ($/kW-Yr)	$ 1.66	(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 2008.

(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 2008.

(4) MAPP operating reserve requirement.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2008
(Integrated System)

A.	Western Regulation Revenue Requirement	$1,256,325	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$106,466	(2)
C.	Total Regulation Revenue Requirement	$1,362,791	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,393,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.57	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.05	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2008, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2008 Watertown Control Area.

Integrated System Load Data

2008 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	**01/29/08**	1900	3,755	490	4,245
2	**02/20/08**	800	4,001	500	4,501
3	**03/07/08**	800	3,769	495	4,264
4	**04/01/08**	800	3,298	501	3,799
5	**05/02/08**	1100	3,038	499	3,537
6	**06/30/08**	1700	3,744	493	4,237
7	**07/15/08**	1700	4,245	487	4,732
8	**08/01/08**	1700	4,174	498	4,672
9	**09/01/08**	1800	3,282	500	3,782
10	**10/28/08**	800	3,329	493	3,822
11	**11/21/08**	800	3,879	501	4,380
12	**12/15/08**	1900	4,366	501	4,867
13					
14	**12 CP**		3,740	497	4,237

2008 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	2513 MW	95 MW	2608 MW
February 8, 2005	9:00	2555 MW	74 MW	2629 MW
March 1, 2005	8:00	2411 MW	74 MW	2485 MW
April 28, 2005	10:00	2116 MW	84 MW	2200 MW
May 23, 2005	17:00	1840 MW	60 MW	1900 MW
June 22, 2005	17:00	2074 MW	97 MW	2171 MW
July 20, 2005	18:00	2337 MW	85 MW	2422 MW
August 8, 2005	18:00	2339 MW	102 MW	2441 MW
September 9, 2005	17:00	2076 MW	64 MW	2140 MW
October 25, 2005	8:00	2186 MW	68 MW	2254 MW
November 16, 2005	19:00	2432 MW	66 MW	2498 MW
December 6, 2005	19:00	2865 MW	103 MW	2968 MW
Total		27,744	972	28,716
			Average Control Area Load	2,393

(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	$48,389,412	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$48,389,412	L4 + L5
7			
8	Net Transmission Plant Investment	$469,409,236	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	10.309%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$12,055,866	A&G Expenses Worksheet, C6L12
16			
17	Net Transmission Plant Investment	$469,409,236	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.568%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$22,194,459	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$469,409,236	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.728%	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	5.631%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	10.309%	L10
49			
50	A&G Expense	2.568%	L19
51			
52	Depreciation Expense	4.728%	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	5.631%	L43
59			
60	Total	23.236%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	23.236%	L60
66			
67	Net Transmission Plant Investment	$469,409,236	L8
68			
69	Annual Western-UGPR Transmission Cost	$109,071,930	L65 * L67
70			

Transmission Revenue from Existing Agreements
Pick Sloan Missouri Basin Program - Eastern Division
FY 2008

Line No.	Description	Amount
1		
2	Montana-Dakota Utilities Company	$501,809
3	MAPP	$2,832,621
4	Standing Rock Sioux Tribe-Cannonball	$2,843
5		
6	**Total**	$3,337,273

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 4/	(6) Total
1						
2	Total Electric Operating Expense	384,491,289	98,147,402			482,638,691
3						
4	Less:					
5	Other Power Supply Expenses	322,108,669	55,742,336			377,851,005
6	A&G Expenses	12,596,951	7,639,348			20,236,299
7	Sunflower Payment		0			0
8	Prior Year Adjustments	308	0			308
9						
10	Plus:					
11	Moveable Property Interest	627,022	318,179			945,201
12	Warehouse Stores Interest	99,898	94,303			194,201
13						
14	COE/BOR Total			32,945,066	31,413,810	64,358,876
15	PS Total O&M	50,512,281	35,178,200	32,945,066	31,413,810	150,049,357
16						
17	PS-ED Transmission O&M 5/	48,027,077	362,335	0	0	48,389,412
18						
19	PS-ED Generation O&M 6/	974,887	0	32,945,066	31,413,810	65,333,763

1/ All Western UGPR O&M Expenses are from the FY 2008 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 2008 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 Corps O&M Expenses are from the FY 2008 Corps of Engineers Financial Statements

4/ Total BOR O&M Expenses are from the FY 2008 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14.

5/ 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.

6/ 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	23,188,791 1/	14,228,852 2/	10,996,652 3/	3,947,014 4/	52,361,309
3						
4	PS-ED Transmission Depreciation 5/	22,047,902	146,557	0	0	22,194,459
5						
6	PS-ED Generation Depreciation 6/	447,544	0	10,996,652	3,947,014	15,391,210

1/ FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2008 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. All COE facilities moved to generation, therefore, there is no COE transmission 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	2,267,743	1,565,248	0	0	3,832,991
3	1412	2,061,068	2,540,416	0	0	4,601,484
4	1415	(69,725)	(41,842)	0	0	(111,567)
5	1416	(51,240)	(45,421)	0	0	(96,661)
6	1431	0	0	0	0	0
7	1432	1,011	0	0	0	1,011
8	1441	4,613,209	2,666,939	0	0	7,280,148
9	1442	3,774,885	954,008	0	0	4,728,893
10	**PS Total A&G**	12,596,951	7,639,348	0	0	20,236,299
11						
12	**PS-ED Transmission A&G 4/**	11,977,181	78,685	0	0	12,055,866
13						
14	**PS-ED Generation A&G 5/**	243,121	0	0	0	243,121

1/ Western UGPR A&G Expenses are from the FY 2008 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 2008 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	954,563,109	1/	612,929,825	2/	934,288,846	3/	417,548,224	12/	2,919,330,004
3	PS-ED Transmission Plant-in-Service	907,551,848	4/	6,296,120	5/	0	6/	0		913,847,968
4	PS-ED Generation Plant-in-Service	18,413,407	7/	0		934,288,846	L2-L3	417,548,224	L2-L3	1,370,250,477
5	Generation Plant to Total Plant	0.0193	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.9508	L3/L2	0.0103	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	464,766,970	8/	246,436,577	9/	512,465,615	10/	210,282,807	11/	1,433,951,969
9	PS-ED Trans. Accumulated Depreciation	441,900,435	L6*L8	2,538,297	L6*L8	0	13/	0	L6*L8	444,438,732
10	PS-ED Gen. Accumulated Depreciation	8,970,003	L5*L8	0	L5*L8	512,465,615	L8-L9	210,282,807	L5*L8	731,718,425
11	PS-ED Net Transmission Plant	465,651,413	L3-L9	3,757,823	L3-L9	0	L3-L9	0	L3-L9	469,409,236
12	PS-ED Net Generation Plant	9,443,404	L4-L10	0	L4-L10	421,823,231	L4-L10	207,265,417	L4-L10	638,532,052

1/ Transmission Plant-in-Service Worksheet, C2L516
2/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2008 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L516.
5/ Transmission Plant-in-Service Worksheet, C5L525.
6/ Transmission Plant-in-Service Worksheet, C5L529.
7/ Transmission Plant-in-Service Worksheet, C4L516.
8/ FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2008 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ Formerly used to account for transmission related accumulated depreciation on the COE switchyards. All COE facilities moved to generation so no transmission depreciation.

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 2008 Balances	579,942,315	1/	345,079,628	1/	516,834,776	1/	91,879,927	1/	1,533,736,646	
4											
5	**Interest Expenses:**										
6	FY 2008 Simple Interest	32,606,541	2/	23,803,397	2/	17,684,925	2/	4,279,732	2/	78,374,595	
7	Average Interest Rate	5.622%	L6/L3	6.898%	L6/L3	3.422%	L6/L3	4.658%	L6/L3		
8	Transmission Plant Factor	0.9931	3/	0.0069	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.631%	7/
10	Generation Plant Factor	0.0134	8/	0.0000	9/	0.6818	10/	0.3047	11/		
11	Weighted Gen. Composite Rate									3.828%	12/

1/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2008 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 a	(2) FY2008 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
1	Transmission Lines					
2	AURORA- BROOKINGS 115-KV T/L	133,158			133,158	
3	AURORA-FLANDREAU 115-KV T/L	96,623			96,623	
4	BEULAH-GARRISON	352,214			352,214	
5	BISMARCK-GLENHAM	5,000,750			5,000,750	
6	BISMARCK-JAMESTOWN NO. 1	5,473,497			5,473,497	
7	BISMARCK-JAMESTOWN NO. 2	3,096,816			3,096,816	
8	BISMARCK-MEDORA	4,770,063			4,770,063	
9	BROOKINGS-SIOUX FALLS	1,174,861			1,174,861	
10	BROOKINGS-WATERTOWN NO. 1	1,741,958			1,741,958	
11	BROOKINGS-WATERTOWN NO. 2	3,318,558			3,318,558	
12	BROOKINGS-WHITE 115/230KV	2,952,237			2,952,237	
13	CARRINGTON-JAMESTOWN	377,544			377,544	
14	CHARLIE CREEK-BELFIELD	13,674,183			13,674,183	
15	CONRAD-SHELBY #2	5,804,318			5,804,318	
16	CRESTON-MARYVILLE	1,366,481			1,366,481	
17	DAWSON COUNTY - MILES CITY	2,605,678			2,605,678	
18	DAWSON-GLENDIVE	553,800			553,800	
19	DAWSON-MEDORA	2,862,712			2,862,712	
20	DAWSON-MEDORA	5,088			5,088	
21	DAWSON-O'FALLON CREEK	954,040			954,040	
22	DAWSON-WILLISTON	1,258,900			1,258,900	
23	DENISON-CRESTON	8,902,841			8,902,841	
24	DEVILS LAKE-CARRINGTON	7,408,621			7,408,621	
25	DEVILS LAKE-LAKOTA	1,872,142			1,872,142	
26	EDGELEY-FORMAN	377,081			377,081	
27	EDGELEY-GROTON	771,572			771,572	
28	ELK CREEK-NEWELL-MAURINE 115-kV T/L	60,704			60,704	
29	FARGO-GRAND FORKS	2,369,098			2,369,098	
30	FARGO-MORRIS	6,910,157			6,910,157	
31	FORMAN-SUMMIT (BISMARCK)	922,098			922,098	
32	FORMAN-SUMMIT (HURON)	487,534			487,534	
33	FORT PECK-DAWSON #1	481,450			481,450	
34	FORT PECK-DAWSON #2	7,919,832			7,919,832	
35	FORT PECK-HAVRE	28,806,330			28,806,330	
36	FORT PECK-WHATELY	157,876			157,876	
37	FORT PECK-WILLISTON	10,004,221			10,004,221	
38	FORT PECK-WOLF POINT #2	7,663,747			7,663,747	
39	FORT RANDALL-FORT THOMPSON 1&2	6,717,269			6,717,269	
40	FORT RANDALL-GAVIN'S POINT	1,151,719			1,151,719	
41	FORT RANDALL-GREGORY	799,107			799,107	
42	FORT RANDALL-MT VERNON	967,828			967,828	
43	FORT RANDALL-O'NEILL	502,230			502,230	
44	FORT RANDALL-SIOUX CITY 1&2	8,532,125			8,532,125	
45	FORT THOMPSON-GRAND ISLAND	16,397,505			16,397,505	
46	FORT THOMPSON-HURON 230-KV 1&2	5,033,030			5,033,030	
47	FORT THOMPSON-SIOUX FALLS 1&2	9,542,122			9,542,122	
48	GARRISON-BISMARCK 230KV 1&2	5,176,778			5,176,778	
49	GARRISON-JAMESTOWN	4,306,775			4,306,775	
50	GARRISON-MALLARD	1,266,645			1,266,645	
51	GARRISON-WM. J. NEAL	1,540,944			1,540,944	
52	GAVINS POINT-BELDEN	455,727			455,727	
53	GAVINS POINT-SIOUX FALLS	1,452,277			1,452,277	
54	GRANITE FALLS- MORRIS	3,279,089			3,279,089	
55	GRANITE FALLS-MINNESOTA VALLEY	156,778			156,778	
56	GREAT FALLS-CONRAD	12,811,702			12,811,702	
57	GREGORY-MISSION	2,010,227			2,010,227	
58	GROTON-HURON	1,212,199			1,212,199	
59	GROTON-SUMMIT	3,176,751			3,176,751	
60	HAVRE-RAINBOW	4,292,348			4,292,348	

Line No.	(1) DESCRIPTION a	(2) FY2008 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
61	HAVRE-SHELBY#2	5,561,905			5,561,905	
62	HESKETT-DEVAUL	434,209			434,209	
63	HETTINGER-NEW UNDERWOOD	11,022,622			11,022,622	
64	HURON-MT VERNON	617,623			617,623	
65	HURON-WATERTOWN 230KV 1&3	4,886,323			4,886,323	
66	JAMESTOWN-EDGELEY	324,360			324,360	
67	JAMESTOWN-FARGO NO. 1	4,941,649			4,941,649	
68	JAMESTOWN-FARGO NO. 2	3,155,850			3,155,850	
69	JAMESTOWN-GRAND FORKS	14,639,184			14,639,184	
70	JAMESTOWN-VALLEY CITY	1,055,414			1,055,414	
71	LEEDS-DEVILS LAKE	2,323,057			2,323,057	
72	LEEDS-ROLLA	322,883			322,883	
73	MALLARD-RUGBY	1,282,436			1,282,436	
74	MARTIN-MISSION	1,816,904			1,816,904	
75	MARTIN-PHILIP	1,790,108			1,790,108	
76	MAURINE-RAPID CITY	4,592,789			4,592,789	
77	MILES CITY-BAKER	8,470,654			8,470,654	
78	MILES CITY-CUSTER	3,750,704			3,750,704	
79	NEW UNDERWOOD-PHILIP	2,116,605			2,116,605	
80	NEW UNDERWOOD-RAPID CITY NO. 1	1,067,598			1,067,598	
81	NEW UNDERWOOD-RAPID CITY NO. 2	309,991			309,991	
82	NEW UNDERWOOD-STEGALL (HURON)	2,672,947			2,672,947	
83	OAHE-FORT THOMPSON 230KV 1&2	3,149,034			3,149,034	
84	OAHE-FORT THOMPSON 230KV 3&4	5,119,119			5,119,119	
85	OAHE-GLENHAM	5,768,280			5,768,280	
86	OAHE-MAURINE	1,791,779			1,791,779	
87	OAHE-NEW UNDERWOOD	6,447,607			6,447,607	
88	OAHE-PIERRE	388,816			388,816	
89	O'FALLON CREEK-MILES CITY	1,607,339			1,607,339	
90	PIERRE-PHILIP	1,187,034			1,187,034	
91	RAPID CITY-ELK CREEK 115-kV T/L	52,064			52,064	
92	RUGBY-LEEDS	1,738,658			1,738,658	
93	SHELBY-SHELBY#2	576,090			576,090	
94	SIOUX CITY-DENISON	1,661,311			1,661,311	
95	SIOUX CITY-SPENCER	1,938,353			1,938,353	
96	SIOUX FALLS- SIOUX CITY	3,217,192			3,217,192	
97	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	277,897			277,897	
98	SUMMIT-WATERTOWN	6,743,203			6,743,203	
99	TIBER TAP-TIBER	1,084,858			1,084,858	
100	UTICA JCT-SIOUX FALLS	3,496,153			3,496,153	
101	VALLEY CITY-FORMAN	1,527,895			1,527,895	
102	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM	312,931			312,931	
103	WATERTOWN-GRANITE FALLS 1&2	5,269,587			5,269,587	
104	WATERTOWN-SIOUX CITY	26,679,769			26,679,769	
105	WATFORD CITY-BEULAH	1,401,905			1,401,905	
106	WILLISTON-WATFORD CITY	563,079			563,079	
107	WM. J. NEAL-RUGBY	4,629,316			4,629,316	
108	YELLOWTAIL-CUSTER	2,265,163			2,265,163	
109	Subtotal	399,520,205	0	0	399,520,205	
110						
111	Substations					
112	ARMOUR SUBSTATION	2,024,198	(82,000)		1,942,198	
113	ASH SUBSTATION	63,325			63,325	
114	AURORA SUBSTATION	2,899,881			2,899,881	
115	BELDEN SUBSTATION	187,367			187,367	
116	BELFIELD SUBSTATION	8,092,824			8,092,824	
117	BERESFORD SUBSTATION	3,494,954	(594,142)		2,900,812	17% of the costs of this facility have been allocated to distribution
118	BISBEE SUBSTATION	272,529	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution
119	BISMARK SUBSTATION	8,049,455			8,049,455	
120	BISON	12,472			12,472	
121	BOLE SUB (BEFP)	91,756			91,756	
122	BOLE SUB (BEPS)	3,131,201			3,131,201	
123	BONESTEEL SUBSTATION	3,442,909	(1,721,454)		1,721,455	50% of the costs of this facility have been allocated to distribution

Line No.	(1) DESCRIPTION	(2) FY2008 TOTALS TOTALS	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS GEN ADJ	(5) TRANSMISSION TOTALS TRANS TOTAL	(6) SOURCE/NOTES
124	BROOKINGS SUBSTATION	3,880,456			3,880,456	
125	CARRINGTON SUBSTATION	3,756,722	(488,374)		3,268,348	13% of the costs of this facility have been allocated to distribution
126	CIRCLE SUBSTATION	1,507,470			1,507,470	
127	CONRAD SUB	311,656			311,656	
128	CONRAD SUB (BEPS)	5,040,068			5,040,068	
129	CRESTON SUBSTATION	4,957,491	(55,000)		4,902,491	
130	CROSSOVER SUB	172,082			172,082	
131	CROSSOVER SUB	11,108,808			11,108,808	
132	CUSTER SUBSTATION (BEFP)	3,189,684			3,189,684	
133	CUSTER SUBSTATION	1,322,622			1,322,622	
134	CUSTER TRAIL SUBSTATION	1,475,222	(737,611)		737,611	50% of the costs of this facility have been allocated to distribution
135	DAWSON COUNTY SUBSTATION	10,923,428	(873,874)		10,049,554	8% of the costs of this facility have been allocated to distribution.
136	DENISON SUBSTATION	16,024,051			16,024,051	
137	DEVAUL SUBSTATION	867,667	(520,600)		347,067	60% of the costs of this facility have been allocated to distribution
138	DEVILS LAKE SUBSTATION	2,591,935	(285,113)		2,306,822	11% of the costs of this facility have been allocated to distribution
139	EAGLE BUTTE SUBSTATION	1,252,804			1,252,804	
140	EDGELEY SUBSTATION	3,477,612	(486,866)		2,990,746	14% of the costs of this facility have been allocated to distribution
141	ELK CREEK SUBSTATION	2,078,657			2,078,657	
142	ELLENDALE SUBSTATION	579	(579)		0	
143	EXIRA SWITCHING STATION	5,500,776			5,500,776	
144	FAITH SUBSTATION	1,223,906	(611,953)		611,953	50% of the costs of this facility have been allocated to distribution.
145	FARGO SUBSTATION	20,561,012	(47,000)		20,514,012	
146	FLANDREAU SUBSTATION	3,646,064	(619,831)		3,026,233	17% of the costs of this facility have been allocated to distribution.
147	FORMAN SUBSTATION	3,946,551	(513,052)		3,433,499	13% of the costs of this facility have been allocated to distribution
148	FORT RANDALL	253,780			253,780	
149	FORT THOMPSON #2	7,773,840			7,773,840	
150	FORT THOMPSON SUBSTATION	14,778,998	(354,000)		14,424,998	
151	GLENDIVE SUBSTATION	1,725,310			1,725,310	
152	GRAND FORKS SUBSTATION	9,337,549			9,337,549	
153	GRAND ISLAND SUBSTATION	9,191,166			9,191,166	
154	GRANITE FALLS SUBSTATION	14,804,870	(57,000)		14,747,870	
155	GREAT FALLS SUB (BEFP)	87,834			87,834	
156	GREAT FALLS SUB	470,826			470,826	
157	GREGORY SUBSTATION	1,544,246	(308,849)		1,235,397	20% of the costs of this facility have been allocated to distribution.
158	GROTON SUBSTATION	3,927,719			3,927,719	
159	HAVRE SUBSTATION	5,698,870	(968,808)		4,730,062	17% of the costs of this facility have been allocated to distribution
160	HILKEN SUSTATION	3,874,407			3,874,407	
161	HURON SUBSTATION	11,191,027			11,191,027	
162	JAMESTOWN SUBSTATION	18,241,559	(1,824,156)		16,417,403	10% of the costs of this facility have been allocated to distribution
163	KILLDEER SUBSTATION	434,273			434,273	
164	LAKOTA SUBSTATION	1,297,443	(428,156)		869,287	33% of the costs of this facility have been allocated to distribution
165	LEEDS SUBSTATION	1,428,288	(199,960)		1,228,328	14% of the costs of this facility have been allocated to distribution
166	MARTIN SUBSTATION	1,578,885			1,578,885	
167	MARYVILLE SUBSTATION	1,525			1,525	
168	MAURINE SUBSTATION	5,716,998			5,716,998	
169	MIDLAND SUBSTATION	676,396			676,396	
170	MILES CITY #2	4,767,418			4,767,418	
171	MILES CITY #2 (BEFP)	935,177			935,177	
172	MILES CITY SUB #3	1,669,005			1,669,005	
173	MILES CITY SUB #3 (BEFP)	226,697			226,697	
174	MILES CITY SUBSTATION (BEFP)	160,336			160,336	
175	MILES CITY SUBSTATION	714,993			714,993	
176	MISSION SUBSTATION	2,656,411			2,656,411	
177	MORRIS SUBSTATION	7,818,483			7,818,483	
178	MT VERNON SUBSTATION	1,896,247			1,896,247	
179	NEW UNDERWOOD SUBSTATION	7,331,764	(806,494)		6,525,270	11% of the costs of this facility have been allocated to distribution
180	NEWELL SUBSTATION	1,058,004			1,058,004	
181	Non-Facility	263,535			263,535	
182	O'FALLON CREEK SUBSTATION	2,020,730	(1,010,365)		1,010,365	50% of the costs of this facility have been allocated to distribution.
183	PHILIP SUBSTATION	2,043,504			2,043,504	
184	PIERRE SUBSTATION	4,482,776	(2,241,388)		2,241,388	50% of the costs of this facility have been allocated to distribution.
185	RAINBOW SUBSTATION	723,556			723,556	
186	RAPID CITY SUBSTATION	3,784,655			3,784,655	

Line No.	(1) DESCRIPTION		(2) FY2008 TOTALS TOTALS		(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS		(4) GENERATION ADJUSTMENTS GEN ADJ		(5) TRANSMISSION TOTALS TRANS TOTAL		(6) SOURCE/NOTES
		a		b		c		d		e	
187	RICHLAND SUBSTATION		1,555,034		(1,244,027)				311,007		80% of the costs of this facility have been allocated to distribution
188	ROLLA SUBSTATION		979,520		(244,880)				734,640		25% of the costs of this facility have been allocated to distribution
189	RUDYARD SUBSTATION		2,585,060		(439,460)				2,145,600		17% of the costs of this facility have been allocated to distribution.
190	RUGBY SUBSTATION		5,873,906		(822,347)				5,051,559		14% of the costs of this facility have been allocated to distribution.
191	SAVAGE SUB		74,403						74,403		
192	SHELBY SUBSTATION		1,055,671						1,055,671		
193	SHELBY SUBSTATION #2 (BEFP)		226,456						226,456		
194	SHELBY SUBSTATION #2 (BEPS)		4,194,041						4,194,041		
195	SIOUX CITY #2		9,393,406						9,393,406		
196	SIOUX CITY SUBSTATION		15,655,346		(57,000)				15,598,346		
197	SIOUX FALLS SUBSTATION		6,499,091						6,499,091		
198	SPENCER		3,240,715						3,240,715		
199	SULLY BUTTES		74,428						74,428		
200	SUMMIT SUBSTATION		2,724,431						2,724,431		
201	TYNDALL SUBSTATION		880,286						880,286		
202	UTICA JCT.		139,641						139,641		
203	VALLEY CITY SUBSTATION		2,792,491						2,792,491		
204	VERONA		25,210						25,210		
205	VIRGIL FODNESS SUBSTATION		3,225,412						3,225,412		
206	WALL SUBSTATION		1,609,013		(804,506)				804,507		50% of the costs of this facility have been allocated to distribution
207	WARD SUBSTATION		3,448,181						3,448,181		
208	WASHBURN SUBSTATION		2,056,003						2,056,003		
209	WATERTOWN #2		2,995,163						2,995,163		
210	WATERTOWN STATIC VAR SYSTEM		11,703,689						11,703,689		
211	WATERTOWN SUBSTATION		13,701,593						13,701,593		
212	WATFORD CITY SUB		1,371,744		(30,000)				1,341,744		
213	WHATELY (NORTHERN)		40,860						40,860		
214	WHATELY SUBSTATION		109,910		(54,955)				54,955		50% of the costs of this facility have been allocated to distribution
215	WHITE 345/115 SUB		9,966,232						9,966,232		
216	WICKSVILLE SUBSTATION		692,796		(346,398)				346,398		50% of the costs of this facility have been allocated to distribution
217	WILLISTON SUBSTATION		6,684,168						6,684,168		
218	WINNER SUBSTATION		3,222,359		(1,611,179)				1,611,180		50% of the costs of this facility have been allocated to distribution
219	WOLF POINT SUBSTATION		7,273,738		(2,182,121)				5,091,617		30% of the costs of this facility have been allocated to distribution.
220	WOONSOCKET SUBSTATION		2,378,168						2,378,168		
221	YANKTON SUBSTATION		302,095						302,095		
222	Subtotal		425,919,555		(23,809,765)		0		402,109,790		
223											
224	Line Taps & Related Equipment										
225	ANITA		6,259						6,259		
226	ASSINNIBOINE		35,005						35,005		
227	BAKER (BEFP)		133,554						133,554		
228	BAKER		97,832						97,832		
229	CANYON FERRY (BEFP)		15,145						15,145		
230	CANYON FERRY		30,065						30,065		
231	CHARLIE CREEK		1,131,114						1,131,114		
232	COTTON		1,399						1,399		
233	DENBIGH TAP		848,872						848,872		
234	DICKINSON		63,736						63,736		
235	E. J. MANNING		51,274						51,274		
236	EAGLE		156,285						156,285		
237	FORSYTH		32,070						32,070		
238	FORSYTH		273,368						273,368		
239	HARLEM		174,745						174,745		
240	HARLEM (BEFP)		16,015						16,015		
241	HETTINGER		4,451						4,451		
242	HIGHWOOD		22,896						22,896		
243	LAKE PLATTE		2,628						2,628		
244	MALLARD		37,325						37,325		
245	MALTA		42,173						42,173		
246	NASHUA SUB		72,368						72,368		
247	O'NEILL SUB (NPP)		115,790						115,790		
248	PENN TAP		890,607						890,607		
249	POPLAR (MDU)		3,758						3,758		

Line No.	(1) DESCRIPTION	a	(2) FY2008 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
250	PRIMGHAR		575						575		
251	SHIRLEY TAP		22,102						22,102		
252	SPALDING		22,234						22,234		
253	STANLEY		49,735						49,735		
254	STEGALL 230KV (BCPS)		3,599						3,599		
255	TERRY TAP		78,497						78,497		
256	TERRY TAP		345,850		(172,925)				172,925		50% of the costs of this facility have been allocated to distribution.
257	TIBER TAP		166,306		(83,153)				83,153		50% of the costs of this facility have been allocated to distribution.
258	VETAL TAP		232,375						232,375		
259	V. T. HANLON		8,749						8,749		
260	WITTEN		25,430						25,430		
261	WM. J. NEAL		166,336						166,336		
262	YANKTON JCT.		30,753						30,753		
263	ZENITH		2,047						2,047		
264	Subtotal		5,413,324		(256,078)		0		5,157,246		
265											
266	O&M Service & Maintenance Centers										
267	ARMOUR O&M SER. CEN.		3,491,212						3,491,212		
268	BISMARCK O&M SER. CEN.		8,922,090						8,922,090		
269	DAWSON SER. CEN.		22,545						22,545		
270	DEVILS LAKE O&M SER. CEN.		3,852,064						3,852,064		
271	Fargo Line Maintenance Facility		968,751						968,751		
272	FARGO O&M SER. CEN.		794,673						794,673		
273	FORT PECK SER. CEN.		5,793,310						5,793,310		
274	FORT THOMPSON O&M S. C.		315,000						315,000		
275	HAVRE SERVICE CENTER		249,377						249,377		
276	HURON O&M SER. CEN.		2,447,467						2,447,467		
277	JAMESTOWN O&M SER. CEN.		3,751,248						3,751,248		
278	MILES CITY MTCE FAC.		21,817						21,817		
279	MILES CITY MTCE FAC.		1,003,437						1,003,437		
280	NEW UNDERWOOD SER. CEN.		96,884						96,884		
281	PHILIP O&M SER. CENT.		1,705,195						1,705,195		
282	PIERRE O&M SER. CEN.		1,047,818						1,047,818		
283	RAPID CITY GARAGE & STOR.		2,055,932						2,055,932		
284	SIOUX CITY O&M SER. CEN.		3,016,572						3,016,572		
285	SIOUX FALLS O&M SER. CEN.		77,456						77,456		
286	WATERTOWN MAINT. CEN.		1,208,780						1,208,780		
287	Subtotal		40,841,628		0		0		40,841,628		
288											
289	Operation Centers										
290	WATERTOWN OPERATIONS CENT		3,043,390				(973,885)		2,069,505		
291	WATERTOWN OPER CTR (BFPS)		8,233,848				(2,634,831)		5,599,017		
292	Subtotal		11,277,238		0		(3,608,716)		7,668,522		
293											
294	Mobile Equipment										
295	MOB 115KV SWITCH TRAILER		12,328						12,328		
296	MOB 115KV SWITCH TRAILER		57,413						57,413		
297	MOB TRANSF 111KV 15MVA		213,000						213,000		
298	MOB TRANSF 115KV 10MVA		76,258						76,258		
299	MOB TRANSF 115KV 10MVA		142,235						142,235		
300	MOB TRANSF 115KV 25MVA		556,464						556,464		
301	MOB TRANSF 115KV 40MVA		499,220						499,220		
302	MOB TRANSF 230KV 1-33MVA		170,278						170,278		
303	MOB TRANS		248,943						248,943		
304	MOBILE BY PASS KIT (BISMARCK)		35,071						35,071		
305	MOBILE BY PASS KIT (HURON)		163,695						163,695		
306	MOBILE CAPACITOR BANK		19,075						19,075		
307	MOBILE SUB 110KV		127,144						127,144		
308	MOBILE SUB 115KV 20MVA		404,166						404,166		
309	MOBILE SUB 41.8 KV		192,498						192,498		
310	MOBILE SUB 69KV		71,118						71,118		
311	MOB SH.REACTOR		179,328						179,328		
312	Subtotal		3,168,233		0		0		3,168,233		

Line No.	(1) DESCRIPTION a	(2) FY2008 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
313						
314	**Transmission-Related Generation Facilities**					
315	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
316	CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
317	CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
318	FORT PECK POWERPLANT (COE)	8,380		(8,380)	0	
319	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
320	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
321	Subtotal	1,985,311	0	(1,985,311)	0	
322						
323	**Communication Facilities**					
324	ATLANTIC COMMUNICATION SITE	17,199		(5,640)	11,559	Column 4 shows 32.79% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation
325	BAKER RELAY	27,791		(9,113)	18,678	
326	BANTRY	268,530		(88,051)	180,479	
327	BARRETT	244,695		(80,236)	164,459	
328	BATTLE MT. MICROWAVE	470,739		(154,355)	316,384	
329	BELLE PRAIRIE	16,111		(5,283)	10,828	
330	BELLE PRAIRIE	577,323		(189,304)	388,019	
331	BENEDICT	36,772		(12,057)	24,715	
332	BEULAH	10,679		(3,502)	7,177	
333	BIG BEND	113,362		(37,171)	76,191	
334	BIJOU REPEATER	603,315		(197,827)	405,488	
335	BISMARCK REPEATER	405,324		(132,906)	272,418	
336	BISON REPEATER	204,957		(67,205)	137,752	
337	BOLE NORTH REPEATER	149,228		(48,932)	100,296	
338	BRINSMADE	237,551		(77,893)	159,658	
339	BRISTOL	11,441		(3,752)	7,689	
340	BRUNSVILLE REPEATER	201,619		(66,111)	135,508	
341	BUFFALO	255,051		(83,631)	171,420	
342	CAHOON	240,466		(78,849)	161,617	
343	CARRINGTON REPEATER	726,855		(238,336)	488,519	
344	CHARTER OAK REPEATER	12,546		(4,114)	12,546	
345	CHARTER OAK REPEATER	3,121		(1,023)	3,121	
346	CHINOOK (BEFP)	284,048		(93,139)	190,909	
347	CHINOOK REPEATER	15,293		(5,015)	10,278	
348	CLARK MW REPEATER	588,027		(192,814)	395,213	
349	CLEVELAND REPEATER, N.D.	263,617		(86,440)	177,177	
350	COLEMAN REPEATER	288,294		(94,532)	193,762	
351	COLOME REPEATER	469,005		(153,787)	315,218	
352	CONRAD BUTTE REPEATER	371,283		(121,744)	249,539	
353	CONRAD BUTTE REPEATER	84,384		(27,670)	56,714	
354	CRESTON REPEATER	11,107		(3,642)	7,465	
355	CROW LAKE REPEATER	311,803		(102,240)	209,563	
356	CROWN BUTTE	202,445		(66,382)	136,063	
357	CULBERTSON RADIO RELAY SITE	1,926		(632)	1,294	
358	CUSTER LOOKOUT	194,017		(63,618)	130,399	
359	DALTON (WES)	198,021		(64,931)	133,090	
360	DEVILS LAKE REPEATER	467,927		(153,433)	314,494	
361	DODSON REPEATER	276,812		(90,767)	186,045	
362	DOGDEN BUTTE	281,286		(92,234)	189,052	
363	DRISCOLL	196,774		(64,522)	132,252	
364	DUPREE REPEATER	1,821		(597)	1,224	
365	DUTTON REPEATER	315,739		(103,531)	212,208	
366	EAST RAINY BUTTE	287,339		(94,218)	193,121	
367	ECKELSON	288,401		(94,567)	193,834	
368	ELKTON	323,756		(106,160)	217,596	
369	ELLENDALE REPEATER	319,122		(104,640)	214,482	
370	ELLSWORTH AIR BASE	59,669		(19,565)	40,104	
371	ERHARD	301,773		(98,951)	202,822	
372	EXIRA REPEATER	50,556		(16,577)	33,979	
373	F. L. BLAIR	110,712		(36,302)	74,410	
374	FAIRPOINT REPEATER	339,030		(111,168)	227,862	
375	FALLON REPEATER	271,939		(89,169)	182,770	

Line No.	(1) DESCRIPTION a	(2) FY2008 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
376	FERGUS FALLS COMMUNICATIONS SITE	485,567		(159,217)	326,350	
377	FLOWING WELLS	68,763		(22,547)	46,216	
378	FORBES COMMUNICATION SITE	45,316		(14,859)	30,457	
379	FORT PECK RELAY (WES)	250,960		(82,290)	168,670	
380	FORT THOMPSON REPEATER	306,861		(100,620)	206,241	
381	FORT THOMPSON REPEATER (EAST RIVER)	301,614		(98,899)	202,715	
382	FOX CREEK MICROWAVE	579,063		(189,875)	389,188	
383	FRYBURG SUB & MICROWAVE	210,967		(69,176)	141,791	
384	GARRISON	249,702		(81,877)	167,825	
385	GARY REPEATER	228,494		(74,923)	153,571	
386	GAVIN'S POINT	46,061		(15,103)	30,958	
387	GAVINS POINT REPEATER	411,445		(134,913)	276,532	
388	GETTYSBURG REPEATER	296,476		(97,215)	199,261	
389	GLENHAM	293,701		(96,305)	197,396	
390	GRAND FORKS MINNKOTA (MPC)	23,847		(7,819)	16,028	
391	HAILSTONE BUTTE	188,523		(61,817)	126,706	
392	HALLOWAY REPEATER	266,614		(87,423)	179,191	
393	HATHAWAY	17,314		(5,677)	11,637	
394	HATHAWAY	191,777		(62,884)	128,893	
395	HERMOSA MICROWAVE	302,701		(99,256)	203,445	
396	HIGHLAND REPEATER	177,964		(58,354)	119,610	
397	HIGHMORE REPEATER	251,511		(82,471)	169,040	
398	HINSDALE	201,837		(66,182)	135,655	
399	HINSDALE REPEATER	25,153		(8,248)	16,905	
400	HOPEWELL REPEATER	393,011		(128,868)	264,143	
401	HUNTER MICROWAVE	307,546		(100,844)	206,702	
402	HURON DISTRICT OFFICE	787,981		(258,379)	529,602	
403	HYSHAM	250,143		(82,022)	168,121	
404	JAMESTOWN REPEATER	46,981		(15,405)	31,576	
405	JONES CREEK	251,034		(82,314)	168,720	
406	KELLY CREEK	15,210		(4,987)	10,223	
407	KELLY CREEK	300,277		(98,461)	201,816	
408	KILLDEER REPEATER	369,183		(121,055)	248,128	
409	KNEE HILL MW	308,285		(101,087)	207,198	
410	KNEE HILL MW	119,303		(39,119)	80,184	
411	KONES CORNER REPEATER	470,207		(154,181)	316,026	
412	LAC QUI PARLE	747,619		(245,144)	502,475	
413	LAKE ANDES REPEATER	743,352		(243,745)	499,607	
414	LEFOR	186,943		(61,299)	125,644	
415	LINDSAY RIDGE	235,489		(77,217)	158,272	
416	LINTON COMMUNICATIONS SITE	339,867		(111,442)	228,425	
417	LODGEPOLE REPEATER	186,559		(61,173)	125,386	
418	MALTA REPEATER	289,599		(94,960)	194,639	
419	MANDAN MICROWAVE SITE	69,988		(22,949)	47,039	
420	MAPLE RIVER	172,792		(56,659)	116,133	
421	MARTIN REPEATER	288,354		(94,551)	193,803	
422	MAYVILLE	331,361		(108,653)	222,708	
423	MIDLAND REPEATER	660,339		(216,525)	443,814	
424	MILES CITY SUB (BEFP)	305,418		(100,147)	205,271	
425	MOE REPEATER	317,411		(104,079)	213,332	
426	MOORHEAD	251,422		(82,441)	168,981	
427	MORRIS REPEATER & MICROWAVE	331,303		(108,634)	222,669	
428	NEWCASTLE REPEATER	216,330		(70,935)	145,395	
429	OAHE	483,358		(158,493)	324,865	
430	O'KREEK REPEATER	508,754		(166,820)	341,934	
431	ORCHARD REPEATER	51,068		(16,745)	34,323	
432	OTO MICROWAVE	16,445		(5,392)	11,053	
433	OTTUMWA ROAD REPEATER SITE	7,685		(2,520)	5,165	
434	PAGE N.D.	1,646		(540)	1,106	
435	PAHOJA SUB	66,444		(21,787)	44,657	
436	PEAK	264,351		(86,681)	177,670	
437	PHILIP JCT. REPEATER	545,125		(178,746)	366,379	
438	PICKSTOWN REPEATER	10,134		(3,323)	6,811	

Line No.	(1) DESCRIPTION	(2) FY2008 TOTALS TOTALS	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS GEN ADJ	(5) TRANSMISSION TOTALS TRANS TOTAL	(6) SOURCE/NOTES
		a	b	c	d	e
439	PINE RIDGE	15,766		(5,170)	10,596	
440	PINE RIDGE	273,894		(89,810)	184,084	
441	PRIMGHAR REPEATER	11,990		(3,931)	8,059	
442	PUKWANNA REPEATER	258,360		(84,716)	173,644	
443	RAPID CITY REPEATER	354,281		(116,169)	238,112	
444	RICHARDSON COULEE	225,741		(74,020)	151,721	
445	RICHARDSON COULEE REPEATER	24,536		(8,045)	16,491	
446	RICHLAND MW REPEATER (BEPS)	532,827		(174,714)	358,113	
447	ROCKY RIDGE REPEATER	226,934		(74,412)	152,522	
448	ROLLAG	172,922		(56,701)	116,221	
449	RUGBY REPEATER	276,659		(90,716)	185,943	
450	RUTLAND	388,869		(127,510)	261,359	
451	SACO	1,237		(406)	831	
452	SENTINEL BUTTE	215,320		(70,603)	144,717	
453	SHEEP COULEE REPEATER	475,744		(155,997)	319,747	
454	SIOUX CITY REPEATER	576,462		(189,022)	387,440	
455	SIOUX FALLS REPEATER	367,833		(120,613)	247,220	
456	SIOUX PASS	1,366		(448)	918	
457	SNAKE BUTTE REPEATER	732,730		(240,262)	492,468	
458	SPALDING REPEATER	36,491		(11,965)	24,526	
459	SPIRIT MOUND	226,293		(74,201)	152,092	
460	STRASBERG	17,870		(5,860)	12,010	
461	SUMMIT REPEATER	50,053		(16,412)	33,641	
462	TAPPEN COMMUNICATIONS SITE	291,767		(95,670)	196,097	
463	TAPPEN REPEATER	272,393		(89,318)	183,075	
464	TENNANT COMMUNICATIONS SITE	8,782		(2,880)	5,902	
465	TORONTO REPEATER	285,888		(93,743)	192,145	
466	TRIPP REPEATER	186,047		(61,005)	125,042	
467	TRIPP REPEATER	46,216		(15,154)	31,062	
468	TURKEY RIDGE REPEATER	569,163		(186,629)	382,534	
469	TYLER REPEATER	449,771		(147,480)	302,291	
470	VICTOR (EREC)	35,530		(11,650)	23,880	
471	VIDA	14,357		(4,708)	9,649	
472	VIDA	323,156		(105,963)	217,193	
473	WALL REPEATER	461,034		(151,173)	309,861	
474	WATERTOWN REPEATER	699,939		(229,510)	470,429	
475	WAYSIDE	118,156		(38,743)	79,413	
476	WESSINGTON SPGS. REPEATER	562,416		(184,416)	378,000	
477	WESTFIELD	19,003		(6,231)	12,772	
478	WHITE SWAN	116,529		(38,210)	78,319	
479	WHITLOCK	47,673		(15,632)	32,041	
480	WHITLOCK (BCPS)	117,922		(38,666)	79,256	
481	WOLBACH REPEATER	52,848		(17,329)	35,519	
482	YELLOWTAIL SWITCHYARD (BEPS)	271,476		(89,017)	182,459	
483	Subtotal	39,095,396	0	(12,819,380)	26,276,016	
484						
485	Miles City Converter Station					
486	MILES CITY CONVERTER STATION	21,535,806			21,535,806	
487	MILES CITY CONVERTER STATION	1,274,402			1,274,402	
488	Subtotal	22,810,208	0	0	22,810,208	
489						
490	Distribution Facilities					
491	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	650,001	(650,001)		0	
492	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	
493	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	
494	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
495	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
496	FORT PECK-WOLF POINT	190,500	(190,500)		0	
497	FRAZER PUMP SUB	253,597	(253,597)		0	
498	GARRISON-SNAKE CREEK	569,241	(569,241)		0	
499	GLENDIVE P.P. #1 SUB.	425,706	(425,706)		0	
500	INTAKE SUBSTATION	108,040	(108,040)		0	
501	INTAKE-INTAKE PUMP	6,494	(6,494)		0	

Line No.	(1) DESCRIPTION a	(2) FY2008 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
502	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
503	SHIRLEY PUMP SUBSTATION	127,053	(127,053)		0	
504	SNAKE CREEK PUMP SUBSTATI	662,435	(662,435)		0	
505	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
506	TIBER DAM SUBSTATION	318,568	(318,568)		0	
507	WIOTA SUBSTATION	38,507	(38,507)		0	
508	Subtotal Distribution Facilities	4,532,013	(4,532,013)	0	0	
509						
510	Subtotal Upper Great Plains Region Facilities	954,563,109	(28,597,854)	(18,413,407)	907,551,848	
511						
512						
513						
514	Rocky Mountain Region Facilities					
515	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2008 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
516	STEGALL SUBSTATION	8,927,702	(8,625,093)		302,609	
517	STEGALL-WAYSIDE	2,978,205			2,978,205	
518	YELLOWTAIL SWITCHYARD	10,909,879	(8,182,409)		2,727,470	
519		23,103,622	(16,807,502)	0	6,296,120	
520						
521	Corps of Engineers Facilities					
522	CORPS SWITCHYARD FACILITIES	29,782,666		(29,782,666)	0	
523		29,782,666	0	(29,782,666)	0	
524						
525	TOTAL FACILITIES	1,007,449,397	(45,405,356)	(48,196,073)	913,847,968	

Western's Ancillary Services Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2008 (WESTERN'S COSTS)

A. Fixed Charge Rate	16.508%	(1)
B. Generation Net Plant Costs ($)	$475,144,224	(2)
C. Annual Cost of Generation ($)	$78,436,808	(A x B)
D. Capability Used for Reactive Support (%)	3.03%	(3)
E. Reactive Service Revenue Requirement	$2,376,635	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2008.

(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 2004-2008.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2008
(Western's Costs)

A.	Fixed Charge Rate	14.245%	(1)
B.	Corps Generation Net Plant Costs ($)	172,649,091	(2)
C.	Annual Corps Generation Cost ($)	24,593,863	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	26.25	(C / D)
F.	Capacity Used for Regulation (kW)	47,860	(H x 2%)
G.	Regulation Revenue Requirement ($)	$1,256,325	(E x F)
H.	Load in Control Area(s) (kW-Yr)	2,393,000	(3)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2008.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/08.

(3) Average of monthly peaks for 2008 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	$65,333,764	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$638,532,052	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	10.232%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$243,121	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$638,532,052	L6
16			
17	A&G as % of Net Generation Plant Investment	0.038%	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	15,391,210	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$638,532,052	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.410%	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	3.828%	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	10.232%	L8
47			
48	A&G Expense	0.038%	L17
49			
50	Depreciation Expense	2.410%	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	3.828%	L41
57			
58	Total	16.508%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	16.508%	L59
64			
65	Net Generation Plant Investment	$638,532,052	L6
66			
67	Western Annual Generation Revenue Requirement	$105,408,871	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	$32,945,066	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$421,823,231	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	7.810%	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	$421,823,231	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	$10,996,652	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$421,823,231	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.607%	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	3.828%	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	7.810%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.607%	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	3.828%	L41
57			
58	Total	14.245%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	14.245%	L69
64			
65	Net Corps Generation Plant Investment	$421,823,231	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$60,088,719	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 12/31/08

Line No.			Total	Allocator		Total Transmission	IS Transmission	MBPP Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ 73,711,754	$ 41,855,442	$ 9,177,036	$ 22,679,275
								$ (8,571,379)	
	Third Party Revenue Receipts and Payments								
2	Third Party Receipts		$ 1,164,802	TP	1.00000		$ 1,164,802	$ -	
3									
4	Third Party Payments		$ 97,532	TP	1.00000		$ 97,532	$ -	
5		(line 2 - 4)	$ 1,067,270				$ 1,067,270		
6	NET REVENUE REQUIREMENT	(line 1 + 5) (IS & MBPP)					$ 40,788,172	$ 605,657	
							$ 41,393,829		

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

	(1)	(2) RUS Form 12 Reference	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) LRS Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE (Note A)										
1	Production	12h.A.6.e	1,927,449,810	NA	0.000%	-	NA	0.000%	-	-	-
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	517,721,662	DA		517,721,662	DA		312,584,855	90,527,447	114,609,342
3	Distribution	12h.A.15.e	-	NA	0.000%	-	NA	0.000%	-	-	
4	General	12h.A.17.e	127,538,635								
4a	Direct Assign - Transmission	12h.A.17.e	40,084,890	DA		40,084,890	DA		28,831,198	4,181,570	7,072,131
4b	Direct Assign - Production	12h.A.17.e	29,610,240	NA	0.000%	-	NA	0.000%	-	-	
4c	Other	12h.A.17.e	57,843,505	WS	11.477%	6,636,517	WS	(page 4)	3,789,674	500,236	2,346,607
5	Intangible	12h.A.1.e	71,683,380	DA		67,450,255	DA		30,470,606	2,617,629	34,362,020
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.23.e	$ 2,644,393,487	GP	23.896%	$ 631,895,324	GP	23.896%	$ 375,676,336 14.207%	$ 97,826,882 3.699%	$ 158,392,106 5.990%
	ACCUMULATED DEPRECIATION										
7	Production (Note A)	12h.B.1-4.f	1,008,751,919	NA	0.000%	-	NA	0.000%		-	
8	Transmission (Note A & B)	12h.B.5.f & 12h.B.15.f	252,774,368	DA		252,774,368	DA		177,303,272	50,699,196	24,771,900
9	Distribution	12h.B.6.f	-	NA	0.000%		NA	0.000%			
10	General	12h.B.7.f	86,035,334								
10a	Direct Assign - Transmission		25,265,911	DA		25,265,911	DA		20,262,212	2,114,927	2,888,772
10b	Direct Assign - Production		21,370,217	NA	0.000%		NA	0.000%			
10c	Other		39,399,207	WS	11.477%	4,521,723	WS	(page 4)	2,591,278	340,728	1,599,718
11	Intangible	12h.B.12.f	42,835,352	DA		42,471,648	DA		19,399,702	1,756,113	21,315,833
12	TOTAL ACCUM DEPR (sum lines 7,8,10,11)	12h.B.18.f less 12h.B.14.f	$ 1,390,396,983			$ 325,033,651			$ 219,546,464	$ 54,910,964	$ 50,576,222
	37 NET PLANT IN SERVICE										
13	Production	(line 1 - line 7)	918,697,891	AUTO			AUTO		-	-	
14	Transmission	(line 2 - line 8)	264,947,294	AUTO		264,947,294	AUTO		135,281,595	39,828,250	89,837,442
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	
16	General	(line 4 - line 10)	41,503,301	AUTO		-	AUTO		-	-	
16a	Direct Assign	(line 4a - line 10a)	14,818,979	AUTO		14,818,979	AUTO		8,568,977	2,066,643	4,183,359
16b	Production	(line 4b - line 10b)	8,240,023	AUTO		-	AUTO		-	-	
16c	Other	(line 4c - line 10c)	18,444,298	AUTO		2,116,794	AUTO		1,208,395	159,508	748,890
17	Intangible	(line 5 - line 11)	28,848,018	AUTO		24,978,607	AUTO		11,070,904	861,517	13,046,187
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,253,996,504	NP	24.471%	$ 306,861,673	NP	24.471%	$ 156,129,872 12.451%	$ 42,915,918 3.422%	$ 107,815,683 8.598%

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

For the 12 months ended 12/31/08

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) MBPP Transmission	Other Transmission
	O&M										
1	Transmission less Account 565	12a.A.8.b+ A.16.b.-12i.A.8.a	20,516,056	NA	0.000%	-	NA	0.000%	-	-	
2	Direct Assignment (Note C)	Accounting Records	10,218,777	DA		10,218,777	DA		7,417,836	2,189,353	611,588
3	Other	Accounting Records	10,297,279	TPW	100.000%	10,297,279	TPW	(page 4)	6,357,371	-	3,939,908
4	A&G	12a.A.13.b	47,904,212			-					
5	Less Regulatory Fees	Accounting Records	126,127	NA	0.000%	-	NA	0.000%	-	-	
6	Production (Note D)	Accounting Records	2,180,652	NA	0.000%	-	NA	0.000%	-	-	
7	Transmission (Note E)	Accounting Records	1,272,773	DA		1,272,773	DA		223,102	600,735	448,936
8	Headquarters		44,324,661	WSW	10.704%	4,744,711	WSW	(page 4)	2,929,306	-	1,815,404
9	TOTAL O&M (sum lines 1 and 4)		$ 68,420,268			$ 26,533,540			$ 16,927,615	$ 2,790,088	$ 6,815,836
	DEBT SERVICE										
10	Interest Expense	12a.A.22-23.b	55,970,671	NP	24.471%	13,696,413	NP	(page 2)	6,968,675	1,915,502	4,812,236
11	Principal Payments	12h.H.c	78,597,527	NP	24.471%	19,233,362	NP	(page 2)	9,785,850	2,689,868	6,757,644
12	Amort of Debt Discount (428)	12a.A.26.b	11,938,617								
13	Transmission	Accounting Records	2,281,878	DA		2,281,878	DA/TPW	(page 4)	1,141,729	432,575	707,574
14	Headquarters	Accounting Records	163,455	WSW	10.704%	17,497	WSW	(page 4)	10,802	-	6,695
15	Production	Accounting Records	9,441,720	NA	0.000%		NA	0.000%			
16	Exclude	Accounting Records	51,563	NA	0.000%		NA	0.000%			
17	Other Deductions	12a.A.26.b	5,151,832	NA	0.000%		NA	0.000%			
18	TOTAL DEBT SERVICE (sum lines 10, 11, 12,17)		$ 151,658,647			$ 35,229,150			$ 17,907,057	$ 5,037,945	$ 12,284,149
	TAXES OTHER THAN INCOME TAXES										
19	PLANT RELATED										
20	Property total										
21	Tax Reclassification			NA	0.000%	-	NA	0.000%			
22	Gross Receipts (Note F)	12a.A.21.b	2,303,288	DA		2,303,288	DA		2,113,041	-	190,246
23	Production			NA	0.000%	-	NA	0.000%	-	-	
24	TOTAL OTHER TAXES		$ 2,303,288			$ 2,303,288			$ 2,113,041	$ -	$ 190,246
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 222,382,203			$ 64,065,978			$ 36,947,713	$ 7,828,033	$ 19,290,231
26	Margin (Page 2, line 18 * Page 4, WCC less line 10)		$ 39,417,664	Net Plant	24.471%	$ 9,645,777	Net plant	(page 2)	$ 4,907,729	$ 1,349,003	$ 3,389,045
27	REV. REQUIREMENT (sum lines 25 + 26)		$ 261,799,867			$ 73,711,754			$ 41,855,442	$ 9,177,036	$ 22,679,275

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) West Transmission	(8) Other Transmission
1	Production		37,222,742					2,754,650	353,639	$1,707,287
2	Transmission-East		284,477							
3	Transmission-West		353,639	WS	Trans % of total wages	11.477%		6.552%	0.865%	4.060%
4	Transmission-Allocated		4,177,660	WSW	Exclude West trans	10.704%		6.609%	0.000%	4.096%
5	Distribution		-							
6	Other Transmission		-	TPW	Trans % of total trans		(Trans % excluding West)	61.738%	0.000%	0.38262
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$42,048,518	TP	Trans % of total trans		Includes West Transmission	57.086%	7.535%	35.378%

Weighted Cost of Capital (WCC)

		Percent	Rate	Weighted Cost %
LTD	1,516,988,145	64.35%	5.81%	3.74%
Equity	840,403,980	35.65%	10.85%	3.87%
	2,357,392,125	100.00%		7.61%

IS Transmission Wage and Salary Dollar Split

Line #				
8	Net IS transmission Plant (p.2.c.6.L14, 16a, 17)	154,921,476		
9	Net West Transmission Plant (p.2..c.7.L14, 16a, 17	42,756,410		
10	Net Other transmission Plant (p.2.c.8.L.14, 16a,17)	107,066,993		
11	Total (sum lines 8-9)	$304,744,879		Non Direct Wages Allocation
12	Percent of IS to Total Transmission (Note G)		ISTP	59.133%
13	Percent of Other to total Transmission		Other	40.867%
				100.000%
14	IS Trans Wage & Salary Dollar (L 4 times L 11)	$2,470,373		
15	West Trans Wage & Salary Dollar (no allocation)	$0		
16	Other Transmission Wage & Salary (L 4 times L 12)	$1,707,287		
17	Total Transmission Wage and Salary Allocated (L.4)	$4,177,660		

Note

A Plant in Service does not include Electric Plant Held for Future Use of $9,018,991 or accumulated depr of $28,334.
Groton clutch recorded in production RUS Account for $1,922,004 is assigned to IS transmission. Accumulated depr is $159,167.

B Includes Acquisition Adjustment of $2,825,409, Groton clutch for $1,922,004 and accumulated depreciation of $71,263 and $159,167.

C 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. MBPP per project billing.

D A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages.

E Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.

F 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.

G MBPP net plant ($42,756,410) is excluded in the percentage calculations on line 12 and 13, column 5, as costs for transmission and A&G are directly allocated to MBPP per project billing.

Basin Electric Power Cooperative
Lines
December 31, 2008

Worksheet 1
Page 1

CPX	Lines	Book Cost	Accum Depr	Net Book	Annual Depreciation
009	230KV LOS#1 to Logan (NSP)	751,708	528,517	223,191	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	8,159,942	1,137,653	258,964
022	345 kv line - SD to Ft Thompson	9,134,431	7,799,010	1,335,421	240,854
023	345 kv line Stanton to SD Border	11,511,850	9,987,867	1,523,982	305,497
024	345 kv line SD to Watertown	10,164,504	8,602,607	1,561,897	312,739
025	230 kv line LOS#1 to Logan	4,430,205	3,242,313	1,187,892	110,453
026	230 kv line-230/115/69-sub (16)	289,132	247,599	41,533	8,076
031	115 kv line Logan to Kenmare	3,115,809	2,190,781	925,028	74,950
032	115 kv line Logan to Mallard	632,973	430,577	202,396	14,649
034	230 kv line Philip Tap-Philip Sub	853,709	762,778	90,931	23,222
127	345 kv N line #1 dbl circ	12,442,227	4,633,206	7,809,021	242,061
128	345 kv S line #2 dbl circ	11,215,381	5,221,245	5,994,136	202,527
129	500 kv AVS switchyd to SD bdr	57,926,565	27,564,175	30,362,390	1,066,860
130	500 kv SD bdr to Broadland sub	53,098,066	25,163,684	27,934,381	973,967
134	345 kv dbl circ line	942,053	621,464	320,589	28,287
141	230 kv line Broadland to Huron	1,068,625	533,143	535,482	20,646
150	230 kv line Estavan to Sask bdr	15,071,877	10,278,748	4,793,129	391,077
152	345 kv line AVS to Charlie Creek	11,655,656	5,799,171	5,856,485	360,046
185	230 kv line MC-Bowman-NU	9,481,900	7,200,054	2,281,846	271,110
234	115Kv Line-Char Ck-Sqw Gab Sub	1,594,137	3,656	1,590,480	3,656
236	115Kv Line-ND/MT Brd-Richld Sb	281,424	645	280,778	645
311	115 kv tie line to Groton sub	136,010	90,771	45,240	4,427
361	69KV Line Cornbelt	41,112	5,752	35,361	1,200
411	230 KV Line RC to New Underwood	6,010,877	755,878	5,254,999	144,502
	Total IS Lines	**$ 232,633,108**	**$ 131,273,988**	**$ 101,359,120**	**$ 5,081,105**

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Basin Electric Power Cooperative
Substations
December 31, 2008

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	1,139,725	95,270	26,262
036	345KV FT Thompson Substation	2,374,699	2,034,502	340,196	102,000
039	230/115KV Storla, SD Substation	2,207,566	1,813,342	394,224	111,912
040	230/115KV Philip, SD Substation	862,865	735,712	127,153	38,063
042	230KV Philip,SD Tap Substation	214,957	194,188	20,769	5,884
046	Martin, SD USBR Sub Capacitor Installed	200,287	149,940	50,347	8,340
047	Armour, SD USBR Sub Capacitor Installed	137,379	123,953	13,426	4,013
058	115KV Williston, ND Substation	643,259	463,326	179,933	18,467
060	230/115KV Dickinson, ND Substation	1,204,038	1,081,716	122,322	33,495
061	115KV Spirit Mound Switchyard	1,406,589	1,175,986	230,604	39,305
063	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,967	1,369,768	278,198	52,163
126	500KV Broadland SD, Substation	12,470,254	6,203,386	6,266,867	243,503
142	230KV USBR Huron Substation Addition	1,669,836	839,130	830,705	32,471
145	Manning,ND Sub Capacitor Installed	186,623	151,618	35,005	5,186
153	345/115KV Charlie Creek Substation	5,342,496	3,631,389	1,711,107	146,513
194	Bowman Sub -230 KV breakers	1,393,433	234,609	1,158,824	38,735
195	Hettinger Capacitors	827,735	115,578	712,157	22,789
196	Baker Capacitors	827,735	115,578	712,157	22,789
310	345/115KV Groton Substation Addition	5,019,759	3,152,062	1,867,697	138,288
325	230 mw Miles City DC Tie	18,989,386	12,155,077	6,834,309	525,716
362	69KV Substation - Cornbelt	1,030,460	145,041	885,419	30,271
408	RC Tie East Interconnect	1,060,552	154,392	906,160	29,469
470	Groton Clutch	2,004,077	164,815	1,839,263	59,432
711	230KV LO #1 Switchyard and AVS Addition	5,087,828	4,233,007	854,821	133,410
720	345/230KV LO#2 Switchyard and AVS Add	16,127,179	10,463,462	5,663,717	388,144
734	Tioga substation - Capacitor bank	387,866	181,479	206,387	10,675
735	345/230KV Watertown Substation	2,871,896	2,587,511	284,385	79,486
737	230/115KV Logan Substation & Sask Addition	4,115,005	3,047,257	1,067,749	110,311
767	345KV AVS Switchyard & Charlie Creek Add't	18,809,313	9,643,916	9,165,397	385,527
	Total IS Substations	$ 110,427,627	$ 67,571,762	$ 42,855,865	$ 2,842,618
CPX	Substations	Book Cost	Depr	Book	Depreciation

Basin Electric Power Cooperative
Maintenance Buildings & Microwave
December 31, 2008

Worksheet 1
Page 3

CPX	Maintenance Buildings	Book Cost	Accum Depr	Net Book	Annual Depreciation
070	Mandan Transmission Maint Bldg	6,514,346	4,757,250	1,757,095	206,870
071	Gettysburg Trans Maint Bldg	1,099,106	951,506	147,600	33,596
072	Groton Trans Maint Bldg	2,135,518	1,159,704	975,814	144,727
109	Logan Trans Maint Bldg	1,477,502	974,716	502,786	52,395
119	Broadland Trans Maint Bldg	1,079,389	1,009,699	69,690	31,824
120	AVS Plantsite Trans Maint Bldg	4,139,800	3,086,465	1,053,335	124,577
	Total Maintenance Buildings	$ 16,445,661	$ 11,939,341	$ 4,506,320	$ 593,989

CPX	Microwave	Book Cost	Accum Depr	Net Book	Annual Depreciation
043	Microwave - North Dakota	9,683,929	6,449,857	3,234,072	497,979
044	Microwave -South Dakota	4,913,744	3,385,699	1,528,046	277,391
136	Microwave - SD AVS	897,056	728,954	168,102	38,408
137	Microwave - AVS	2,175,315	1,103,733	1,071,582	114,464
139	Microwave - ND Sask	1,340,022	1,114,856	225,165	59,416
155	Microwave - ND CC	1,061,358	875,082	186,277	48,321
308	Microwave - SD Groton	143,259	120,638	22,621	7,723
	Subtotal Microwave	$ 20,214,683	$ 13,778,819	$ 6,435,864	$ 1,043,702
	Non IS transmission 38.756%	(7,834,417)	(5,340,129)	(2,494,288)	(404,498)
	Total Microwave	$ 12,380,266	$ 8,438,690	$ 3,941,576	$ 639,204
	Accum Depr Adjustment		(2,258,595)		
	Total IS Facilities	$ 371,886,662	$ 216,965,186	$ 154,921,476	$ 9,156,916

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Basin Electric Power Cooperative
MBPP Transmission Facilities
December 31, 2008

CPLX	LINES	BOOK COST	12/31/08 ACCUM DEPR	12/31/08 NET BOOK VALUE	12/31/08 YTD DEPR
049	345kv line from LRS-Stegall	5,917,563	3,398,064	2,519,499	109,605
050	345kv line from LRS-Stegall Sub	519,922	290,147	229,775	9,428
051	345KV Line from LRS to NB Border	2,392,317	1,313,304	1,079,014	44,661
052	345KV Line - NB Border To Sidney Sub	3,702,714	2,001,108	1,701,606	68,220
053	345 KV LINE - Stegall Sub to Sidney Sub	4,971,800	2,720,225	2,251,575	93,286
073	230kv line from LRS to D Johnston	2,868,108	1,656,197	1,211,911	48,128
074	345kv line from LRS-Story	18,392,775	10,930,803	7,461,971	313,654
075	345kv line from CO Border to Story Sub	16,558,245	9,526,830	7,031,415	298,355
077	LRS Plantsite Lines	1,255,831	666,208	589,622	27,318
091	NEBRASKA TAX	161,866	87,475	74,391	3,447
096	MBPP-Tri-State	12,498	12,498	-	-
101	230KV Line - Sidney Sub To WAPA Sub	499,280	291,337	207,943	9,182
102	230kv Stegall Tie Line	353,438	196,731	156,708	6,551
103	230KV Tie Line Stegall Sub - Stegall/WAPA	311,212	176,400	134,812	5,679
104	345kv line - 048 to CO Border	8,978,538	4,599,851	4,378,687	158,074
105	345kv line-CO Border to Ault	3,597,852	1,854,640	1,743,211	64,525
106	230kv Sidney Tie Line	268,113	158,346	109,767	5,086
	SUBTOTAL LINES	$ 70,762,073	$ 39,880,167	$ 30,881,906	$ 1,265,199

CPLX	SUBSTATIONS	BOOK COST	12/31/08 ACCUM DEPR	12/31/08 NET BOOK VALUE	12/31/08 YTD DEPR
045	230kv LRS Switch Station	2,289,416	1,263,690	1,025,725	47,524
048	345kv LRS Substation	5,891,131	3,514,788	2,376,343	110,020
076	230kv D Johnson Substation	379,358	222,522	156,836	7,088
078	345/230 KV Stegall Substation	3,014,708	1,748,311	1,266,397	57,979
079	345/230 KV Sidney Substation	4,083,137	2,392,336	1,690,800	77,514
084	230 KV Stegall-WAPA Sub Addition	599,773	341,420	258,353	11,943
086	230kv Story Substation	412,617	233,389	179,228	7,892
100	230/115 KV Sidney Substation Addition	284,620	153,403	131,217	6,022
190	345kv Story Substation	2,823,113	1,554,853	1,268,260	54,517
	SUBTOTAL SUBSTATIONS	$ 19,777,872	$ 11,424,711	$ 8,353,160	$ 380,500

Basin Electric Power Cooperative
West System Transmission Facilities
December 31, 2008

CPX	Description	Installed Costs	Accum Depr	12/31/07 NET BOOK VALUE	12/31/07 YTD DEPR
	MICROWAVE COMMUNICATONS				
131	Microwave Communication-WY	1,316,685	744,733	571,952	72,288
132	Microwave Communication-CO	254,484	157,388	97,096	11,653
133	Microwave - NB	538,174	338,255	199,919	25,021
135	Microwave - ND	-	-	-	-
138	Microwave - SD	36,572	30,127	6,445	2,183
		2,145,915	1,270,503	875,412	111,145
	Less Non-Trans MW (7.863%)	(168,739)	(99,903)	(68,836)	(8,740)
	SUBTOTAL MICROWAVE	$ 1,977,176	$ 1,170,600	$ 806,576	$ 102,405
	MAINTENANCE BUILDING				
107	Trans Maintenance Building - Stegall	1,102,099	938,654	163,445	58,130
108	LRS Trans Maintenance Bldg	1,089,797	791,337	298,460	30,071
	SUBTOTAL MAINTENANCE	$ 2,191,896	$ 1,729,991	$ 461,905	$ 88,201
	OTHER				
085	345kv Ault Substation	2,548,498	1,711,514	836,984	63,536
088	230KV OCB-Tri-State	69,131	44,598	24,533	1,861
	SUBTOTAL OTHER	$ 2,617,629	$ 1,756,113	$ 861,517	$ 65,397
	General Ledger Depr Adjust		(1,391,345)		-
	GRAND TOTAL	$ 97,326,646	$ 54,570,237	$ 42,756,409	$ 1,901,702

Worksheet 2

Basin Electric
Electric Plant In Service
December 31, 2008

	Generation	IS Transmission	West Transmission	BHP Common Use Transmission	Rapid City DC Tie	Excluded Transmission	Headquarters	Totals
Book Basis-Generation	1,927,449,810	1,922,004						1,929,371,814
Accum Depr	(1,008,751,919)	(159,167)						(1,008,911,086)
G/L Adjust -Accum Depr								
Net Book	918,697,891	1,762,837						920,460,728
Book Basis-Transmission	-	310,662,864	90,527,447	49,963,538	37,037,634	27,608,176		515,799,658
Accum Depr		(177,195,819)	(50,699,196)	(5,645,617)	(5,030,703)	(14,095,579)		(252,666,915)
G/L Adjust -Accum Depr		51,714						51,714
Net Book		133,518,759	39,828,250	44,317,921	32,006,931	13,512,596		263,184,457
Book Basis General Plant	21,475,550	5,261	12,498	361,915	74,421	-	57,843,505	79,773,150
TSM Buildings	-	16,445,661	2,191,896	1,361,094	-	44,344		20,042,996
Microwave	8,134,690	12,380,266	1,977,176	1,806,569	361,408	3,062,379		27,722,489
G/L Accum Depr GP	(17,493,987)	(5,261)	(12,498)	(24,128)	(17,892)		(39,882,032)	(57,435,798)
G/L Accum Depr GP-TSM	-	(11,939,341)	(1,729,991)	(286,490)		(924)		(13,956,745)
G/L Accum Depr GP-MW	(4,224,058)	(8,438,690)	(1,170,600)	(386,617)	(113,961)	(2,063,308)		(16,397,234)
G/L Adjust Accum Depr	347,828	121,080	798,162	4,548			482,825	1,754,443
Net Book General Plant	8,240,024	8,568,977	2,066,643	2,836,892	303,976	1,042,491	18,444,298	41,503,301
Book Basis Intangibles	4,230,855	30,470,606	2,617,629	426,659	-	33,935,361	2,270	71,683,380
Accum Depr	(361,444)	(19,399,702)	(1,756,113)	(246,602)		(21,069,231)	(2,270)	(42,835,362)
Net Book Intangibles	3,869,411	11,070,904	861,517	180,057	-	12,866,130	0	28,848,018
Total	930,807,326	154,921,476	42,756,410	47,334,869	32,310,907	27,421,217	18,444,298	1,253,996,504
Other - Plant Held for Furture Use	6,723,703			2,295,288				
Accum Depr	-			(28,334)				
Net Plant 12a.B.5 less B.2 CWIP	6,723,703			2,266,954				1,262,987,161

Basin Electric Power Cooperative
IS Revenue Requirement Worksheet
Third Party Payments and Receipts
December 31, 2008

Worksheet 3

Third Party Payments

LaCreek Electric		97,532
Total Payments	$	97,532

Third Party Receipts

MAPP		1,164,802
Total Receipts	**$**	**1,164,802**

Basin Electric's Ancillary Services Cost Data

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

For the 12 months ended 12/31/08

		East		West		Groton		Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$	300,132,947	$	87,982,144	$	24,417,618	$	13,451,518
Percent of revenue requirement to net plant		55.0654%		39.9575%		20.1635%		22.1243%

	Production		LOS		AVS		SM		LRS		Groton		Other
$	425,984,228	$	94,592,403	$	204,000,967	$	1,539,578	$	87,982,144	$	24,417,618	$	13,451,518

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

For the 12 months ended 12/31/08

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Groton	(11) Other
	GROSS PLANT IN SERVICE (Note A)											
1	Production	12h.A.6.e	1,927,449,810	DA	100.000%	1,927,449,810	294,555,901	853,779,797	24,930,271	559,221,100	125,936,954	66,925,786
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	517,721,662	NA	0.000%							
3	Distribution	12h.A.16.e	-	NA	0.000%	-						
4	General	12h.A.17.e	127,538,635	NA	0.000%	-						
4a	Direct Assign - Transmission	12h.A.17.e	40,484,890	NA	0.000%	-						
4b	Direct Assign - Production	12h.A.17.e	29,610,240	DA	100.000%	29,610,240	10,160,192	8,495,275	553,595	6,683,416	139,975	3,576,886
4c	Other	12h.A.17.e	57,843,505	WS	88.523%	51,204,989	15,030,401	21,355,841	156,950	14,126,695	327,127	187,975
5	Intangible	12h.A.1.e	71,683,381	DA		4,230,855	-	1,049,145	-	-	-	3,181,710
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.23.e	$ 2,644,393,488			2,012,495,894	319,846,495	884,691,059	25,650,816	580,031,211	126,403,955	75,872,357
				GP	76.104%		12.095%	33.455%	0.970%	21.934%	4.780%	2.869%
	ACCUMULATED DEPRECIATION											
7	Production (Note A)	12h.B.1-4.f	1,008,751,918	DA	100.000%	1,008,751,918	174,593,697	448,469,113	21,875,188	344,955,373	5,017,344	13,831,203
8	Transmission (Note B)	12h.B.5.f & 12h.B.15.f	252,774,368	NA	0.000%		-	-	-	-		-
9	Distribution	12h.B.6.f	-	NA	0.000%	-	-	-	-	-		-
10	General	12h.B.7.f	86,035,334	NA	0.000%		-	-	-	-		-
10a	Direct Assign - Transmission		25,265,911	NA	0.000%	-	-	-	-	-		-
10b	Direct Assign - Production		21,370,216	DA	100.000%	21,370,216	8,207,013	6,709,674	217,847	5,254,420	95,780	915,482
10c	Other		39,399,207	WS	88.523%	34,877,485	10,237,725	14,553,012	113,715	9,622,180	222,817	128,036
11	Intangible	12h.B.12.f	42,835,362	DA		361,444	-	163,667	-	-	-	197,777
12	TOTAL ACCUM DEPR (sum lines 7,8,10,11)	12h.B.18.f less 12h.B.14.f	$ 1,390,396,983			$1,065,361,063	193,038,435	469,895,455	22,206,750	359,841,973	5,305,942	15,072,498
	NET PLANT IN SERVICE											
13	Production	(line 1 - line 7)	918,697,892	AUTO		918,697,892	120,062,205	405,310,684	3,055,083	214,255,727	120,919,610	55,094,583
14	Transmission	(line 2 - line 8)	264,947,294	AUTO			-	-	-	-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	-	-	-	-		-
16	General	(line 4 - line 10)	41,503,301	AUTO		-	-	-	-	-		-
16a	Direct Assign	(line 4a - line 10a)	15,218,979	AUTO		-	-	-	-	-		-
16b	Production	(line 4b - line 10b)	8,240,024	AUTO		8,240,024	1,953,179	1,786,602	335,748	1,428,996	74,095	2,661,404

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

For the 12 months ended 12/31/08

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
	O&M											
1	Production	12a.A.5.b+ A.15.b	202,944,812	DA	100.000%	202,944,812	55,123,617	99,856,804	710,792	44,081,934	1,501,574	1,670,091
2	A&G	12a.A.13.b	47,904,212									
3	Less Regulatory Fees	Accounting Records	126,127	NA	0.000%	-	-	-	-	-		-
4	Production (Note C)		2,180,652	DA	100.000%	2,180,652	-	-	-	2,180,652		-
5	Transmission (Note D)		1,272,773	NA	0	-	-	-	-			
6	Headquarters		44,324,661	WSW	84.815%	37,593,841	15,239,388	21,662,918	169,271	-	331,675	190,588
7	TOTAL O&M (sum lines 1 and 2)		$ 250,849,024			242,719,304	70,383,005	121,519,722	880,063	46,262,586	1,833,249	1,860,679
	DEBT SERVICE											
8	Interest Expense	12a.A.22-23.b	55,970,671	NP	75.529%	42,274,258	5,659,930	18,513,917	153,722	9,827,890	5,405,069	2,713,731
9	Principal Payments	12h.H.c	78,597,527	NP	75.529%	59,354,165	7,948,028	25,998,404	215,866	13,800,939	7,590,135	3,810,791
10	Amort of Debt Discount (428)	12a.A.26.b	11,938,617	NA	0.000%							
11	Transmission	Accounting Records	2,281,878	NA	0.000%							
12	Headquarters	Accounting Records	163,455	WSW	84.815%	138,634	56,198	79,885	624	-	1,223	703
13	Production	Accounting Records	9,441,720	DA	0.000%	9,441,720	919,274	6,335,588	27,322	1,341,492	376,322	440,724
14	Exclude	Accounting Records	51,563	NA	0.000%	-	-	-	-	-	-	-
15	Other Deductions	12a.A.26.b	5,151,832	NA	0.000%	-	-	-	-	-	-	-
16	TOTAL DEBT SERVICE (Sum lines 8,9,10,15)		$ 151,658,647			111,218,778	14,583,430	50,928,795	397,534	24,970,321	13,372,750	6,955,948
	TAXES OTHER THAN INCOME TAXES											
17	PLANT RELATED											
18	Property and Other Total		-	GP		-	-	-	-	-	-	-
19	Property Headquarters		-	NA	0.000%	-	-	-	-	-	-	-
20	Gross Receipts Tax	12a.A.21.b	2,303,288	NA	0.000%	-	-	-	-	-	-	-
21	Production (Note E)		-	DA	100.000%	-	-	-	-	-	-	-
22	TOTAL OTHER TAXES		$ 2,303,288			-	-	-	-	-	-	-
23	TOTAL OPERATING EXPENSES (Sum 7+16+22)		$ 404,810,959			353,938,082	84,946,435	172,448,517	1,277,597	71,232,907	15,205,999	8,826,627
24	Margin (Page 2, line 18 * Page 4, WCC less line 8)		$ 95,388,335	NP	75.529%	$72,046,146	$9,645,968	$31,552,449	$261,981	$15,749,237	$9,211,619	$4,624,891
25	REV. REQUIREMENT (sum lines 23 + 24)		$ 500,199,294			$425,984,228	$94,592,403	$204,000,967	$1,539,578	$87,982,144	$24,417,618	$13,451,518

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Line No.	WAGES AND SALARY ALLOCATOR (W/S)											
(1)	(2)	(3) TOTAL	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
1	Production - LOS	$10,926,137	WS	88.523%	$37,222,742	25.965%	36.937%	0.289%	24.422%	0.5655%	0.3250%
2	Production - AVS	$15,531,596	WSW (Excludes LRS)	84.815%	$31,779,316	34.381%	49.873%	0.382%		0.748%	0.430%
3	Production - SM	$121,362									
4	Production - LRS	$10,269,201									
5	Production - Groton	$237,800	PRWS			29.353%	41.726%	0.326%	27.589%	0.639%	0.357%
6	Production - Other	$136,646	PRWSW (Excludes LRS)		$26,953,541	40.537%	57.624%	0.450%		0.882%	0.507%
7	Transmission	$4,825,775									
8	Other	$0									
	Total Wages and Salaries (exclude admin)	$42,048,518									

Weighted Cost of Capital		(WCC) Percent	Rate	Weighted Cost %
LTD	1,516,988,145	64.35%	5.81%	3.74%
Equity	840,403,980	35.65%	10.85%	3.87%
	2,357,392,125	100.00%		7.61%

Note

A Plant in Service does not include Electric Plant Held for Future Use of $9,018,991 or accumulated depr of $28,334.
Groton clutch recorded in production RUS Account for $1,922,004 is assigned to IS transmission. Accumulated depr is $159,167.
B Includes Acquisition Adjustment of $2,825,409, Groton clutch for $1,922,004 and accumulated depreciation of $71,283 and $159,167.
C A&G costs directed allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages.
D Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.
E Production taxes are included in the RUS 500 series of accounts.

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2008

Summary

A	Total LOS and AVS Net Plant Investment	$ 525,372,889	(ancillary worksheet 5)
B	Facilities with AGC (LOS 1 & AVS)	$ 438,638,669	(Ancillary worksheet 5 less LOS 2)
C	B/A	83.4909%	
D	AGC Facilities	$ 67,884	
E	AGC Facilities Percentage (D/B)	0.0155%	
F	Generation Revenue Requirement	$ 249,298,357	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$ 38,582	(E x F)
H	**Regulation Revenue Requirement**	**$ 106,466**	(D + G)

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply and Voltage Control - 2008

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LOS #1	62,150	55.0654%	34,223	33,548	67,771
LOS #2	361,080	55.0654%	198,830	59,499	258,329
AVS #1	1,593,830	55.0654%	877,650	45,167	922,817
AVS #2	320,415	55.0654%	176,438	48,998	225,436
Spirit Mound (Units 1 & 2)	75,038	55.0654%	41,320	858	42,178
Groton (Units 1 & 2)	806,070	20.1635%	162,532	10,541	173,073
LRS - BEPC*	1,185,107	39.9575%	473,539	94,344	37,479
LRS - HCPD	93,664	49.5100%	46,373	6,094	52,467
Reactive Supply and Voltage Control Requirement					$ 1,779,550

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

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Allocation Factor - 2008

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
53			
Groton #1	35.00	127.30	0.070280
Groton #2	35.00	127.30	0.070280
	70.00	254.60	0.070280
LRS Unit #1	300.00	593.00	0.203782
	1,269.00	2,651.60	

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply And Voltage Control Allocation Factor - 2008

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
Groton #1	991	991	370	621	0.626640	290	0.2874
Groton #2	991	991	370	621	0.626640	290	0.2874
LRS Unit #1	4,692	4,692	3,000	1,692	0.360614	505	2.3695
Total							12.8995

Basin Electric Power Cooperative
IS Ancillary Services
Generator Summary 2008

Ancillary
Worksheet 3

Generator Summary
Summer Peak Load
2008

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
659103	ANTEL31	G24.0	2	1	466.9	83.3	200.0	-175.0
659107	ANTEL32	G24.0	2	1	466.9	83.3	200.0	-175.0
659110	LELAN41	G22.0	2	1	225.0	17.6	120.0	-90.0
659111	LELAN32	G20.0	2	1	475.0	-44.9	225.0	-56.0
659116	SPIRIT71	G13.8	2	1	52.0	-7.0	30.0	-15.0
659117	SPIRIT72	G13.8	2	1	52.0	-7.0	30.0	-15.0
659274	GROTON	G13.8	2	1	105.0	2.7	40.0	-10.0
659275	GROTONB7	G13.8	2	1	105.0	2.7	40.0	-10.0
67118	LARAM31	G24	2	1	593.5	48.8	285	-83.0
	TOTAL				**2541.3**	**297.3**	**1170.0**	**629.0**

Generator Summary
Winter Peak Load
2008

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
659103	ANTEL31	G24.0	2	1	465.4	65.9	200.0	-175.0
659107	ANTEL32	G24.0	2	1	465.3	65.9	200.0	-175.0
659110	LELAN41	G22.0	2	1	225.0	28.4	120.0	-90.0
659111	LELAN32	G20.0	-2	1	475.0	-56.0	225.0	-56.0
659116	SPIRIT71	G13.8	-2	0	0.0	0.0	30.0	-15.0
659117	SPIRIT72	G13.8	-2	0	0.0	0.0	30.0	-15.0
659274	GROTON1	G13.8	2	0	105.0	5.5	40.0	-10.0
659275	GROTONB7	G13.8	2	0	105.0	5.5	40.0	-10.0
659118	LARAM31	G24	2	1	593.5	62.7	285	-83.0
	TOTAL				**2434.2**	**289.9**	**1170.0**	**629.0**

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power Costs - 2008

Ancillary
Worksheet 4

Real Power Allocation Ratio - Other Plant

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

$$\frac{12.8995 \text{ MW}}{2{,}651.60 \text{ MW}} \times \frac{297.3 \text{ MVAR}}{1{,}269 \text{ MVAR}} =$$

0.1140%

Reactive Power Costs
Real Power Allocation Ratio - Fuel

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

$$\frac{12.8995 \text{ MW}}{17{,}331{,}142 \text{ MWH}} \times \frac{293.6 \text{ MVAR}}{1{,}269 \text{ MVAR}} =$$

0.1508%

RP & VC Wksht #5

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

Ancillary
Worksheet 5

Generating Plant Costs
As of December 31, 2008
(Net Plant)

Line #	Description	LOS # 1	LOS #2	AVS #1	AVS #2	SM	LRS	Groton	Other	HCPD
1	Generating Plant (ACCT 310-348)	33,327,985	86,734,219	301,576,406	103,734,279	3,055,083	214,255,727	120,919,610	55,094,583	13,207,816
2	**Total Plant**	$ 33,327,985	$ 86,734,219	$ 301,576,406	$ 103,734,279	$ 3,055,083	$ 214,255,727	$ 120,919,610	$ 55,094,583	$ 13,207,816
	Generators									
3	Total Plant	51,621	865,586	3,950,437	(leased)	157,894	2,333,203	2,383,088		238,710
4	Allocated to Reactive Power (Wkst 1)	27.5508%	17.3333%	18.1833%	18.1228%	32.0955%	20.3782%	7.0280%		20.3782%
5	Reactive Power Plant (L3*L4)	$ 14,222	$ 150,035	$ 718,321	$ -	$ 50,677	$ 475,464	$ 167,483		$ 48,645
	Exciters									
6	Total Plant	14,639	61,260	437,004	(leased)	29,800	463,513	420,545		44,679
7	Allocated to Reactive Power (Wkst 2)	65.2510%	65.2535%	65.4222%	65.4222%	65.3372%	36.0614%	62.6640%		36.0614%
8	Reactive Power Plant (L6*L7)	$ 9,552	$ 39,974	$ 285,898	$ -	$ 19,470	$ 167,149	$ 263,530		$ 16,112
	Voltage Regulators									
9	Total Plant	391	69,731	21,850	(leased)	1,490	69,996	71,493		7,161
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		100.0000%
11	Reactive Power Plant (L9*L10)	$ 391	$ 69,731	$ 21,850	$ -	$ 1,490	$ 69,996	$ 71,493		$ 7,161
	Step-Up Transformers									
12	Total Plant	452	172,417	1,510,160	1,371,678	-	1,631,671	714,237		42,262
13	Allocated to Reactive Power (Wkst 6)	6.2500%	1.6162%	14.9306%	14.7569%	33.3333%	14.0580%	23.3133%		14.0580%
14	Reactive Power Plant (L12*L13)	$ 28	$ 2,787	$ 225,475	$ 202,418	$ -	$ 229,380	$ 166,512		$ 5,941
	Other Plant									
15	Total Plant (L2-L5-L8-L11-L14)	33,303,792	86,471,693	300,324,862	103,531,861	2,983,446	213,313,737	120,250,591		13,129,957
16	Allocated to Reactive Power (Wkst 4)	0.1140%	0.1140%	0.1140%	0.1140%	0.1140%	0.1140%	0.1140%		0.1140%
17	Reactive Power Plant (L15*L16)	$ 37,957	$ 98,553	$ 342,286	$ 117,997	$ 3,400	$ 243,118	$ 137,052		$ 14,964
	Total Reactive Power Plant									
18	(L5+L8+L11+L14+L17)	$ 62,150	$ 361,080	$ 1,593,830	$ 320,415	$ 75,038	$ 1,185,107	$ 806,070		$ 92,823
	Fuel Expense									
19	Total	22,239,128	39,442,741	29,941,914	32,481,430	569,012	62,541,513	6,988,008		4,039,661
20	Allocated to Reactive Power (wkst 4)	0.1508%	0.1508%	0.1508%	0.1508%	0.1508%	0.1508%	0.1508%		0.1508%
21	Reactive Power Expense (L19*L20)	$ 33,548	$ 59,499	$ 45,167	$ 48,998	$ 858	$ 94,344	10,541		$ 6,094

Basin Electric Power Cooperative
IS Ancillary Services
Transformer Allocation
December 31, 2008
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
Groton #1 & 2	166	127.3	0.233133
LRS #3	690	593	0.140580

* Emergency Rating

Basin Electric Power Cooperative
Generation Plant
December 31, 2008

Worksheet #7

	LO #1	LO #2	SM #4	AVS #065	AVS #066	Groton	LRS #006	LRS #007	LRS #008	Other	Total
Gross Plant - Production	96,403,500	198,252,401	24,930,271	643,882,357	209,897,440	125,936,954	178,997,188	174,034,776	206,189,136	68,925,786	1,927,449,810
Accum Depr - Production	(63,075,515)	(111,518,182)	(21,875,188)	(342,305,951)	(106,163,162)	(5,017,344)	(115,533,690)	(106,380,270)	(123,051,413)	(13,831,203)	(1,008,751,918)
Net Book	33,327,985	86,734,219	3,055,083	301,576,406	103,734,279	120,919,610	63,463,499	67,654,506	83,137,722	55,094,583	918,697,892
Gross General Plant	3,227,088	3,227,088	240,037	3,884,893	3,884,893	106,001	2,172,825	2,172,760	2,172,760	387,204	21,475,550
G/P Gross Microwave Alloc	1,212,509	2,493,507	313,559	363,244	363,244	33,875	55,025	55,023	55,023	3,189,682	8,134,690
Accum Depr	(2,705,386)	(2,705,386)	(217,847)	(3,138,159)	(3,138,159)	(37,254)	(1,718,931)	(1,718,879)	(1,718,879)	(47,277)	(17,146,159)
Microwave Accum Depr	(1,398,121)	(1,398,121)		(216,677)	(216,677)	(28,526)	(32,576)	(32,577)	(32,577)	(868,205)	(4,224,058)
Net Book	336,091	1,617,089	335,748	893,301	893,301	68,745	476,341	476,327	476,327	339,927	8,240,024
Gross Plant Intangible	-	-	-	524,573	524,573	-	-	-	-	3,181,710	4,230,855
Accum Depr				(81,834)	(81,834)	-				(197,777)	(361,444)
Net Book	-	-	-	442,739	442,739	-	-	-	-	2,983,933	3,869,411

Missouri River Energy Services
Ancillary Services
Cost Data

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Supply and Voltage Control - 2008

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LRS - MRES/WMMPA	$ 277,836	77.6270%	$ 215,676	$ 39,380	$ 255,056
Exira	$ 429,540	11.2727%	$ 48,421	$ 3,653	$ 52,074
Watertown Power Plant	$ 67,416	49.0472%	$ 33,066	$ 117	$ 33,183
					$ 340,313

Generation Revenue Requirement — For the 12 months ended 12/31/08
EIA 412
Missouri River Energy Services/ Western Minnesota

	Production	LRS	WPP	Exira	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 50,168,084	$38,920,603	$2,514,666	$ 8,285,485	$ 447,329
Net Plant	$131,715,458	$50,137,975	$5,127,028	$ 73,500,176	$ 2,950,278
Percent of revenue requirement to net plant	38.09%	77.63%	49.05%	11.27%	15.16%

Generation Revenue Requirement — For the 12 months ended 12/31/08
EIA 412 — Page 2
Missouri River Energy Services/ Western Minnesota

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total		(4) Allocator	(5) Production	WMMPA LRS	WMMPA WPP	WMMPA Exira	WMMPA Wind
	GROSS PLANT IN SERVICE									
1	Production		275,166,065	DA	1.00000	275,166,065	174,486,883	17,842,746	79,287,629	3,548,807
2	Transmission		60,303,731	NA	0.00000	-				
3	Distribution		-	NA		-				
4	General		13,444,625	WS	0.79588	10,700,251	6,785,188	693,842	3,083,220	138,001
4a	Direct Assign - Transmission			NA		-				
4b	Direct Assign - Production			DA		-				
4c	Other			WS		-				
5	Intangible		9,294,997	NA	0.00000					
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)		$ 358,209,418	GP	79.804%	285,866,316	181,272,071	18,536,588	82,370,849	3,686,808
				$ 2						
	ACCUMULATED DEPRECIATION									
7	Production		148,380,843	DA	1.00000	148,380,843	126,225,621	12,907,627	8,538,635	708,961
8	Transmission		32,518,248	NA		-				
9	Distribution			NA		-				
10	General		7,249,894	WS	0.79588	5,770,015	4,908,475	501,933	332,038	27,569
10a	Direct Assign - Transmission			NA		-				
10b	Direct Assign - Production			DA		-				
10c	Other			WS		-				
11	Intangible		5,012,244	DA		-				
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)		$ 193,161,230			154,150,858	131,134,096	13,409,560	8,870,673	736,530
	NET PLANT IN SERVICE									
13	Production	(line 1- line 7)	126,785,222	AUTO		126,785,222	48,261,262	4,935,119	70,748,994	2,839,846
14	Transmission	(line 2- line 8)	27,785,483	AUTO		-				
15	Distribution	(line 3 - line 9)	-	AUTO		-				
16	General	(line 4 - line 10)	6,194,731	AUTO		4,930,236	1,876,713	191,910	2,751,182	110,432
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)	4,282,753	AUTO		-				
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)	12a.B.L5 less L2	$ 165,048,188	NP	79.804%	$ 131,715,458	50,137,975	5,127,028	73,500,176	2,950,278
				$ 2						

Generation Revenue Requirement — For the 12 months ended 12/31/08

EIA 412

Missouri River Energy Services/ Western Minnesota

No.	(1)	(2) Reference	(3) Company Total		(4) Allocator	(5) Production	WMMPA LRS	WPP	Exira	Other
	O&M									
1	Production		17,791,187	DA	1.00000	17,791,187	16,692,961	591,515	429,274	77,437
2	A&G		7,458,554	WS	74.248%	5,537,845	5,195,002	184,120	133,620	24,104
3	Less Regulatory Fees			NA		-				
4	Production			NA						
5	Transmission			NA		-				
6	Headquarters			NA						
7	TOTAL O&M (sum lines 1 and 2)		$ 25,249,741			23,329,032	21,888,963	775,635	562,894	101,541
	DEBT SERVICE									
8	Debt Service- Excluding Transmission Bond Resolution		23,819,148	GP 2	88.676%	21,121,850	13,393,678	1,369,616	6,086,148	272,408
9	Debt Service- Transmission Bond Resolution		2,215,634	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)		$ 26,034,781	$ -	81.129%	21,121,850	13,393,678	1,369,616	6,086,148	272,408
	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		55,795	GP	74.248%	41,427	38,870	1,377	1,000	180
20	Gross Receipts Tax			NA		-				
21	Production (Note C)		481,560	DA	100.000%	481,560	305,364	31,226	138,759	6,211
22	TOTAL OTHER TAXES		$ 537,355			$ 522,987	344,234	32,603	139,758	6,391
23	TOTAL OPERATING EXPENSES (Sum 7+15+22)		$ 51,821,877			44,973,869	35,626,875	2,177,855	6,788,800	380,339
24	Margin	$ -	$ 6,508,695	GP	79.804%	55,194,215	3,293,729	336,811	1,496,685	66,990
25	REV. REQUIREMENT (sum lines 23 + 24)		$ 58,330,573		86.416%	$ 50,168,084	$ 38,920,603	$ 2,514,666	$ 8,285,485	$ 447,329

WAGES AND SALARY ALLOCATOR (W/S)

Line # (1)	(2)		(3) TOTAL	(4) Allocator	(5) Production Allocation	Production W/S Allocator
			$			
1	Production		1,713,972	1.00	1,713,972	74.248%
2	Transmission		454,504	0.00	0	
3	Distribution		0	0.00	0	
4	Other		139,959		-	
5	Total (sum lines 18-21)	$ 2,308,435	$ 2,308,435		$ 1,713,972	

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Allocation Factor - 2008

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	32.69	75.00	0.159650
Exira 1	26.00	71.18	0.117729
Exira 2	26.00	71.18	0.117729
Exira 3	26.00	71.18	0.117729
Total Exira	78.00	213.53	0.117729

** = Used Basin 2007%.

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Supply And Voltage Control Allocation Factor - 2008

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	640	640	552	88	0.137500	285	0.01824
Exira 1	2,977	2,977		2,977	0.249057	185	0.05507
Exira 2	2,977	2,977		2,977	0.249057	185	0.05507
Exira 3	2,977	2,977		2,977	0.249057	185	0.05507
Total Exira *	8,931	8,931		8,931	0.249057	555	0.49567
LRS Unit #1**	4,692	4,692	3,000	1,692	0.360614	505	2.3695
Total					0.2491		3.0486

* = Average of WPP & LRS.
** = Used Basin 2007%.

Missouri River Energy Services/ Western Minnesota
Ancillary

IS Ancillary Services
Worksheet 5

Reactive Power/Voltage Control

Generating Plant Costs
As of December 31, 2008
(Net Plant)

Line #	Description	Basin for LRS- 2007 #s	MRES/WMMPA LRS *	WPP	Exira	Other	Total Gen.	Source
1	Net Generating Plant (ACCT 310-348)	$ 216,421,028	$ 48,261,262	$ 4,935,119	$ 70,748,994	$ 2,839,846	$ 126,785,222	
2	**Total Plant**	$ 216,421,028	$ 48,261,262	$ 4,935,119	$ 70,748,994	$ 2,839,846	$ 126,785,222	
	Generators		1.12%	5.84%	2.50%			
3	Total Plant	2,425,984	540,987	288,211	1,768,725			
4	Allocated to Reactive Power (Wkst 1)	20.3782%	20.3782%	15.9650%	11.7729%			Worksheet 1
5	Reactive Power Plant (L3*L4)	$ 494,371	$ 110,243	$ 46,013	$ 208,229	$ -	$ 364,486	
	Exciters		0.22%	1.10%	0.30%			
6	Total Plant	478,922	106,798	54,365	212,247			
7	Allocated to Reactive Power (Wkst 2)	36.0614%	36.0614%	13.7500%	24.9057%			Worksheet 2
8	Reactive Power Plant (L6*L7)	$ 172,706	$ 38,513	$ 7,475	$ 52,862	$ -	$ 98,850	
	Voltage Regulators		0.03%	0.06%	0.05%			
9	Total Plant	72,780	16,230	2,718	35,374			
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		N/A
11	Reactive Power Plant (L9*L10)	$ 72,780	$ 16,230	$ 2,718	$ 35,374	$ -	$ 54,322	
	Step-Up Transformers		0.79%	0.30%	0.30%			
12	Total Plant	1,704,205	380,033	14,805	212,247			
13	Allocated to Reactive Power (Wkst 6)	14.0580%	14.0580%	35.0000%	21.6667%			Worksheet 6
14	Reactive Power Plant (L12*L13)	$ 239,577	$ 53,425	$ 5,182	$ 45,987	$ -	$ 104,594	
	Other Plant		99.55%	98.76%	99.52%			
15	Total Plant (L2-L5-L8-L11-L14)	215,441,595	48,042,852	4,873,731	70,406,542	2,839,846		
16	Allocated to Reactive Power*	0.1237%	0.1237%	0.1237%	0.1237%			N/A- Used Basin #
17	Reactive Power Plant (L15*L16)	$ 266,484	$ 59,425	$ 6,028	$ 87,087	$ -	$ 152,541	
18	**Total Reactive Power Plant** (L5+L8+L11+L14+L17)	$ 1,245,918	$ 277,836	$ 67,416	$ 429,540	$ -	$ 774,792	
	Fuel Expense							
19	Total	56,511,974	25,305,997	75,381	2,347,369	0		
20	Allocated to Reactive Power*	0.1556%	0.1556%	0.1556%	0.1556%	0.1556%		N/A- Used Basin #
21	Reactive Power Expense (L19*L20)	$ 87,942	$ 39,380	$ 117	$ 3,653	$ -	$ 43,151	

* = Used BEPC 2007 % to allocate MRES LRS $.

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Transformer Allocation

Reactive Power Costs

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	47	0.2166667
Exira 2	60	47	0.2166667
Exira 3	60	47	0.2166667
Total Exira	180	141	0.2166667

** = Used Basin 2007%.

* Emergency Rating

Heartland's Transmission Cost Data

HEARTLAND CONSUMERS POWER DISTRICT 2-Mar-09
INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT
December 31, 2008

MBPP TRANSMISSION FACILITIES

Line	Description	Cost of Service Amount	
1.	Transmission Plant Investment	$7,290,954.06	Page 3, Line L50+Page 5 Line T48
2.	Less Accumulated Depreciation & IDC	($5,195,606.99)	Page 3, Lines M50,N50 + Page 5 Lines U48,V48
3.	General Plant - Trans Share	$187,273.53	Page 3, Line L52 + Page 5 Line T49
4.	Less Accum Depre & IDC-GP-Trans	($106,720.82)	Page 3, Lines M52,N52 + Page 5 Lines U49,V49
5.	Materials & Supplies - Trans	$0.00	Page 2, Lines C92,F92
6.	Cash Working Capital	$12,948.63	1/12 of Line 16 + 17 (this page)
7.	Transmission Investment Rate Base	$2,188,848.40	
8.			
9.	Rate of Return * 6.56%	$143,588.45	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense	$317,664.00	Page 3, Line P50 + Page 5, Line X48
11.	GP Depr Expense - Trans Share	$6,527.03	Page 3, Line P52 + Page 5, Line X49
12.	GP Maintenance	$17,078.99	Page 1, Lines C43,F43
13.	Income Tax	$1,150.89	Page 1, Lines C49,F49
14.	Taxes Other than Income	$27,967.43	Page 1, Lines C55,C59,F55,F59
15.	A & G Expenses	$173,240.27	Page 2, Lines C69, C70, F69, F70
16.	Transmission O & M	$252,667.41	Page 2, Lines C77,F77
17.	Less:Trans of Elect by Others	($97,283.88)	Page 2, Lines C85,F85
18.	Subtotal Transmission Revenue Requirement	$842,600.59	
19.			
20.	Annual Trans Third Party Payment	$0.00	
21.	Annual Trans Third Party Revenue	$0.00	
22.			
23.	Total MBPP Transmission Revenue Requirement	$842,600.59	

TRANSMISSION PROJECTS 1 AND 3 FACILITIES

Line	Description	Cost of Service Amount	
24.	Transmission Plant Investment **	$1,292,610.66	Page 4, Line L68,L71
25.	Less Accumulated Depreciation & IDC **	($522,525.99)	Page 4, Lines M68,M71,N68,N71
26.	General Plant - Trans Share	$111,119.59	Page 4, Line L82
27.	Less Accum Depre & IDC-GP-Trans	($77,855.53)	Page 4, Lines M82,N82
28.	Materials & Supplies - Trans	$0.00	Page 2, Line C91
29.	Cash Working Capital	$4,957.79	1/12 of Line 39 + 40 (this page)
30.	**Transmission Investment Rate Base**	**$808,306.52**	
31.			
32.	Rate of Return * 6.56%	$53,024.91	Line 30 x Line 32 rate (this page)
33.	Transmission Depr Expense **	$31,977.86	Page 4, Line P68,P71
34.	GP Depr Expense - Trans Share	$5,289.20	Page 4, Line P82
35.	GP Maintenance	$2,952.10	Page 1, Line C42
36.	Income Tax	$198.93	Page 1, Line C48
37.	Taxes Other than Income	$6,369.78	Page 1, Lines C54,C57,C60,C61
38.	A & G Expenses	$27,910.04	Page 2, Line C68
39.	Transmission O & M	$59,493.53	Page 2, Line C75,C76
40.	Less:Trans of Elect by Others	$0.00	Page 2, Line C86
41.	**Subtotal Transmission Revenue Requirement**	**$187,216.34**	
42.			
43.	Annual Trans Third Party Payment	$0.00	
44.	Annual Trans Third Party Revenue	$24,799.78	Revenues from MAPP Schedule F
45.			
46.	**Total Transmission Project 1 and 3 Revenue Requirement**	**$162,416.56**	

INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT $1,005,017.16 Line 23 + 46 (this page)

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

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE) k:\data\accounting\transm08

December 31, 2008 2-Mar-09

	HCPD Invest	East Side	Depr	IDC	West Side	Depr	IDC
LRS	$50,153,330.34	$3,509,791.44	30.23%	30.09%	$3,968,436.15	100.00%	100.00%
TP-I	$907,635.18	$907,635.18	7.82%	7.78%		0.00%	0.00%
TP-II	$6,752,305.09	$6,752,305.09	58.15%	57.88%		0.00%	0.00%
TP-II Marshall	$0.00	$0.00	0.00%	0.00%		0.00%	0.00%
TP-III Groton	$384,975.48	$384,975.48	3.32%	3.30%		0.00%	0.00%
	$58,198,246.09	$11,554,707.19			$3,968,436.15		
		9.12%			*7.54%*		
General Plant Improvement	$617,234.18	$56,284.71	0.48%	0.48%	$0.00	0.00%	0.00%
Furniture & Equipment	$143,218.49	$13,059.89		0.11%	$0.00		0.00%
Furniture & Equipment-EPD	$347,810.36	$31,716.33		0.27%	$0.00		0.00%
Transportation Equipment	$55,329.26	$5,045.40		0.04%	$0.00		0.00%
Headquarter's Improvement	$54,976.84	$5,013.26		0.04%	$0.00		0.00%
	$59,416,815.22	$11,665,826.78	100.00%	100.00%	$3,968,436.15	100.00%	100.00%

	Depreciation	East Side	West Side
Accum Depr-Plant	$37,511,004.81	$3,420,575.41	$2,826,571.96
Accum Depr-Gen'l Plant	$486,222.95	$44,337.98	$0.00
Accum Depr-Trans Equip	$52,119.70	$4,752.72	$0.00
	$38,049,347.46	$3,469,666.11	$2,826,571.96

	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	$1,279,073.72	$1,056,954.89

	Annual Depr	East Side	West Side
Depr Exp-Plant	$3,150,000.00	$287,244.04	$237,362.39
Depr Exp-Gen'l Plant	$37,918.82	$3,457.76	$0.00
Depr Exp-Trans Equip	$4,814.27	$439.01	$0.00

	GP Maint	East Side	West Side
HCPD	$120,276.71		
TP1,TP3		$2,952.10	
MBPP		$8,015.76	$9,063.23

	Income Tax	East Side	West Side
HCPD	$8,105.00		
TP1,TP3		$198.93	
MBPP		$540.15	$610.74

	Tax Other Than Income	East Side	West Side
HCPD Payroll	$65,066.02		
TP1,TP3		$1,597.00	
MBPP		$4,336.28	$4,902.93
Headquarter's	$6,789.36		
TP1,TP3		$166.64	
MBPP		$452.47	$511.60
LRS (HCPD)	$125,602.29	$8,789.80	$9,938.42
TP1	$3,000.14	$3,000.14	
TP3	$1,606.00	$1,606.00	

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)
December 31, 2008

	A&G Expenses	East Side	West Side
HCPD	$2,578,273.76		
TP1,TP3		$27,910.04	
MBPP		$75,783.39	$85,686.44
MBPP-LRS	$160,246.27	$5,885.22	$5,885.22
W/S Allocator	0.073		

	Transm O&M	East Side	West Side
TP-I	$57,595.19	$57,595.19	
TP-III	$1,898.34	$1,898.34	
MBPP-Trans	$252,667.41	$126,333.71	$126,333.71

	Trsm by Others	East Side	West Side
LRS-Trans	$97,283.88	$48,641.94	$48,641.94
	$97,283.88	$48,641.94	$48,641.94

	Material & Supplies	East Side	West Side
TP1,TP3		$0.00	
A Acct 163 Balance Sheet Items - MBPP	$0.00	$0.00	$0.00

Rate of Return				
2008 Liability	$52,904,654.51	90.56%	6.42%	5.81%
2008 Net Assets	$5,511,760.76	9.44%	8.00%	0.75%
	$58,416,415.27			6.56%

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE) 2-Apr-09

December 31, 2008

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)	$150,604.64				
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	***$2,351,719.87***				
	MICROWAVE COMMUNICATIONS					
131	Microwave-Wyoming (50%)	$44,171.50				
133	Microwave-Nebraska	$34,979.41				
135	Microwave-North Dakota	$0.00				
138	Microwave-South Dakota	$2,420.74				
		$81,571.65				
	Less Microwave Non-Transmission (70%)	$57,100.16				
	Subtotal Microwave Communications	***$24,471.50***				
	MAINTENANCE BUILDINGS					
107	Maintenance Building-Stegall	$73,021.11				
108	Maintenance Building-LRS (50%)	$35,778.11				
	Subtotal Maintenance Buildings	***$108,799.22***				
	Total LRS Transmission-East Side	***$3,376,520.72***	$994,716.37	$370,211.13	$2,011,593.22	$83,531.66
	Total LRS General Plant-East Side	***$133,270.72***	$39,261.29	$14,612.17	$79,397.25	$3,296.98
	Total LRS-East Side	***$3,509,791.44***	***$1,033,977.66***	***$384,823.30***	***$2,090,990.47***	***$86,828.64***

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE)

December 31, 2008

	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
HEARTLAND TRANSMISSION					
TP-I Irv Simmons	$907,635.18	$267,387.54	$99,515.65	$540,731.99	$22,453.96
TP-II	$6,752,305.09	$1,989,215.82	$740,341.53	$4,022,747.75	$167,045.11
TP-II Marshall	$0.00	$0.00	$0.00	$0.00	$0.00
TP-III Groton Sub	$384,975.48	$113,413.02	$42,209.78	$229,352.68	$9,523.90
Total HCPD Transmission-East Side	*$8,044,915.75*	*$2,370,016.38*	*$882,066.96*	*$4,792,832.41*	*$199,022.97*
HEARTLAND GENERAL PLANT					
General Plant Improvement	$56,284.71	$16,581.37	$6,171.21		$1,392.43
Furniture & Equipment	$13,059.89	$44,337.98	$1,431.92		$3,457.76
Furniture & Equipment-EPD	$31,716.33		$3,477.47		
Transportation Equipment	$5,045.40	$4,752.72	$553.19		$439.01
Headquarter's Improvement	$5,013.26		$549.67		
Total HCPD General Plant-East Side	*$111,119.59*	*$65,672.07*	*$12,183.46*	*$33,264.06*	*$5,289.20*
TOTAL EAST SIDE TRANSMISSION & GENERAL PLANT	*$11,665,826.78*	*$3,469,666.11*	*$1,279,073.72*	*$6,917,086.95*	*$291,140.81*

HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE) 2-Apr-09

December 31, 2008

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	$520,419.42				
105	345 kV Line -CO Border to Ault	$208,610.29				
106	230 kV Sidney Tie Line	$15,568.45				
	Subtotal Lines	*$3,088,558.90*				
	SUBSTATIONS					
045	230 kV LRS Switch Station (4 Terminals)	$136,427.08				
048	345 kV LRS Substation (5 of 8 Trmls)(.57214)	$201,390.49				
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	***$825,874.44***				
	MICROWAVE COMMUNICATIONS					
131	Microwave-Wyoming (50%)	$44,171.50				
132	Microwave-Colorado	$16,577.50				
		$60,749.00				
	Less Microwave Non-Transmission (70%)	$42,524.30				
	Subtotal Microwave Communications	***$18,224.70***				
	MAINTENANCE BUILDINGS					
108	Maintenance Building-LRS (50%)	$35,778.11				
	Subtotal Maintenance Buildings	***$35,778.11***				
	Total LRS Transmission-West Side	***$3,914,433.34***	$2,788,107.73	$1,042,571.76	$83,753.85	$234,132.34
	Total LRS General Plant-West Side	***$54,002.81***	$38,464.23	$14,383.13	$1,155.45	$3,230.05
	Total LRS-West Side	***$3,968,436.15***	***$2,826,571.96***	***$1,056,954.89***	***$84,909.30***	***$237,362.39***

HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)

December 31, 2008

	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	*$3,968,436.15*	*$2,826,571.96*	*$1,056,954.89*	*$84,909.30*	*$237,362.39*

Transmission Customer Facility Credits

Confidential

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)				$ 11,433,059
	REVENUE CREDITS	(Note Q)				
2	Account No. 454	(page 3, line 34)	0	TP	1.00000	0
3	Account No. 456.1	(page 3, line 37)	70,250	TP	1.00000	70,250
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)					70,250
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 11,362,809

Allocation of Net Revenue Requirements by Pricing Zones:	Irv Simmons	OTP	MBPP	Marshall Wind Circuit	Total
Transmission Plant Investment	$ 1,957,786	$ 27,309,547	$ 29,052,153	$ 1,984,245	$ 60,303,731
% of Total Transmission Plant	3.2%	45.3%	48.2%	3.3%	100.0%
Net Transmission Revenue Requirement (Allocated on Transmission Plant)	$ 368,898	$ 5,145,837	$ 5,474,190	$ 373,884	$ 11,362,809

Line			
	DIVISOR		
8	Average of 12 coincident system peaks for requirements (RQ) service	(Note A)	675,337
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)		675,337

Line					Off-Peak Rate
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ 16.825		
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	$ 1.402		
			Peak Rate		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.324		$0.324
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.065	Capped at weekly rate	$0.046
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	4.045	Capped at weekly and daily rates	$1.926
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/08

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 (Note X)		16,642,850	TE	1.0000	16,642,850
1a	Less LSE Expenses included in Transmission O&M Accou		0		1.0000	0
2	Less Account 565		13,138,692		1.0000	13,138,692
3	A&G	VII.13.d	7,458,554	W/S	0.1969	1,468,501
4	Less FERC Annual Fees		0	W/S	0.1969	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		0	W/S	0.1969	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		0	TE	1.0000	0
6	Common		0	CE	0.1969	0
7	Transmission Lease Payments		0		1.0000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		10,962,712			4,972,659
	DEBT SERVICE					
9a	Debt Service - Transmission Bond Resolution (Note T)		2,215,634		1.0000	2,215,634
9b	Debt Service- Excluding Transmission Bond Resolution (Note		23,819,148	GP 2	0.1132	2,697,298
10	Amortization of premium or discount (Note V)		0	GP	0.1808	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		26,034,781			4,912,932
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.1969	0
14	Highway and vehicle		0	W/S	0.1969	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		360,304		1.0000	360,304
16b	Property- General Plant		55,795	GP	0.1808	10,090
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.1808	0
19	Payments in lieu of taxes		0	GP	0.1808	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		416,099			370,394
21	SUBTOTAL (sum lines 8, 11, 20)		37,413,593			10,255,985
22	MARGIN REQUIREMENT (Note H)		6,508,695	GP	0.1808	1,177,074
23	REV. REQUIREMENT (sum lines 21 22)		43,922,288			11,433,059

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/08

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.	GROSS PLANT IN SERVICE	EIA 412 Reference	Company Total	Allocator		Transmission
1	Production	IV.6.f	275,166,065	NA	0.0000	0
2a	Transmission, excluding separa	IV.7.f	32,994,184	TP	1.0000	32,994,184
2b	Separate Transmission Project i	IV.7.f	27,309,547	TP	1.0000	27,309,547
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	22,739,622	W/S	0.1969	4,477,163
5	Common		0	CE	0.1969	0
6	TOTAL GROSS PLANT (sum lines 1-5)		358,209,418	GP	0.1808	64,780,894
6a	Gross Plant Allocator, excluding Separate Transmission Proj		330,899,871	GP 2	0.1132	37,471,347

TRANSMISSION PLANT INCLUDED IN ISO RATES

Line No.			Transmission
7	Total transmission plant (line 2)		60,303,731
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)		60,303,731
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)	TP=	1.00000

TRANSMISSION EXPENSES

Line No.			Transmission
12	Total transmission expenses (page 2, line 1, column 3)		16,642,850
13	Less transmission expenses included in OATT Ancillary Services (Note I)		0
14	Included transmission expenses (line 12 less line 13)		16,642,850
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	1,713,972	0.00	0		
19	Transmission	454,504	1.00	454,504		
20	Distribution	0	0.00	0		
21	Other	139,959		0		
22	Total (sum lines 18-21)	2,308,435		454,504	=	0.1969

COMMON PLANT ALLOCATOR (CE) (Note M)

Line No.		$	% Electric (line 23 / line 26)		Labor Ratio (line 22)		CE
23	Electric	358,209,418	1.00000	*	0.1969	=	0.1969
24	Gas	0					
25	Water	0					
26	Total (sum lines 23-25)	358,209,418					

FINANCING DATA

Line No.			$
27	Long Term Debt	II.33.b +34.b	$232,070,418
28	Debt Service		26,034,781
29	Interest on Long Term Debt III.16.b + III.17.b (Note R)		11,934,781
30	Bond Principal Amortization (line 28 less line 29)		14,100,000

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 456.1 (OTHER ELECTRIC REVENUES)	
35	a. Transmission charges for all transmission transactions	$70,250
36	b. Transmission charges for all transmission transactions included in Divisor on page 1	$0
37	Total of (a)-(b)	$70,250

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/08

Missouri River Energy Services

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)

To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA Form 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
G	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. MRES segregates property taxes between generation, transmission, and general plant based on internal accounting records. Therefore, MRES transmission property taxes are directly assigned to the revenue requirement and general property taxes will be allocated based on the GP allocator. Work papers will be provided."
H	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin. The margin requirement will be allocated on GP.
I	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
J	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
K	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.
L	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6.
M	Enter dollar amounts.
N	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.
O	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
P	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.
Q	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.
R	From Reference II.17.b include only the amount from Account 430.
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	Represents only Debt Service that can be directly assigned to transmission assets and no other types of assets. Work papers will be provided.
U	Represents all Debt Service, other than transmission debt service included in line 9a, page 2. Work papers will be provided.
V	The amortization of debt discounts and premiums are excluded since amortization is a non-cash item that does not affect debt service cash flow. The principal and interest payments already reflect all discounts or premiums when the debt was originally issued.
W	Represents only transmission assets that can be directly assigned to the Transmission Service Agreements and no other types of assets. These transmission assets were financed under the Transmission Bond Resolution. Work papers will be provided.
X	Transmission Expense will be the sum of (a) Form 412 VII.8.d and (b) facility credits for the Irv Simmons project in the Integrated System (IS).

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 2,836,165
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 454	(page 4, line 34)	92,695	TP	0.85831	79,562
3	Account No. 456	(page 4, line 37)	68,119	TP	0.85831	58,467
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.85831	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.85831	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					138,029
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 2,698,136
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	215,250
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 6-14)					229,250
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	11.769			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	0.981			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.226			$0.226
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 5; line 16 / 7)	0.045	Capped at weekly rate		$0.032
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	2.820	Capped at weekly and daily rates		$1.347
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term
22			$0.000	Long Term		$0.000 Long Term

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	RATE BASE:							
	GROSS PLANT IN SERVICE							
1	Production	206.42.g	152,914,360	NA				
2	Transmission	206.53.g	43,901,418	TP	0.85831	37,681,174	6,220,244	
3	Distribution	206.69.g	186,054,722	NA				
4	General & Intangible	206.5.g & 83.g	8,731,227	W/S	0.04990	435,682		
5	Common	356.1	25,208,850	CE	0.03263	822,598		
6	TOTAL GROSS PLANT (sum lines 1-5)		416,810,586	GP=	9.342%	38,939,454		
	ACCUMULATED DEPRECIATION							Accumulated Depreciation of Joint Plant Transmission Facilities
7	Production	219.18-22.c	96,320,066	NA				-5,041,173
8	Transmission	219.23.c	31,597,752	VEst.	84.046%	26,550,579		
9	Distribution	219.24.c	64,220,629	NA				
10	General & Intangible	219.25.c	2,458,478	W/S	0.04990	122,676		
11	Common	356.1	8,927,933	CE	0.03263	291,330		
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		203,533,858			26,970,585		
	NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	56,585,302					
14	Transmission	(line 2- line 8)	12,303,666			11,124,595		
15	Distribution	(line 3 - line 9)	121,834,093					
16	General & Intangible	(line 4 - line 10)	6,272,749			313,006		
17	Common	(line 5 - line 11)	16,280,917			531,268		
18	TOTAL NET PLANT (sum lines 13-17)		213,276,727	NP=	5.612%	11,968,868		
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative	273.8.k	0	NA	zero	0		
20	Account No. 282 (enter negative	275.2.k	-52,370,200	NP	0.05612	-2,938,961		
21	Account No. 283 (enter negative	277.9.k	-4,992,767	NP	0.05612	-280,189		
22	Account No. 190	234.8.c	14,568,576	NP	0.05612	817,573		
23	Account No. 255 (enter negative	267.8.h	-3,497,059	NP	0.05612	-196,251		
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-46,291,450			-2,597,828		
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.84046	0		
	WORKING CAPITAL (Note H)							
26	CWC	calculated	672,891			75,799		
27	Materials & Supplies (Note G)	227.6.c & .15.c	0		1.00000	0		Excluded transmission maintained and supplied by others
28	Prepayments (Account 165)	111.46.d	0	GP	0.09342	0		
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		672,891			75,799		
30	RATE BASE (sum lines 18, 24, 25, & 29)		167,658,168			9,446,839		

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities

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	5,841,797	TE	0.85831	5,767,883		Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	5,320,126		1.00000	5,320,126		
3	A&G	323.168.b	4,861,453	W/S	0.03263	158,636		
4	Less FERC Annual Fees		0	W/S	0.03263	0		
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		0	W/S	0.03263	0		
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.85831	0		
6	Common	356.1	0	CE	0.03263	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)		5,383,125			606,393		
	DEPRECIATION EXPENSE						Excluded	
9	Transmission	336.7.b	895,929	VR800	0.84046	710,975	184,954	
10	General	336.9.b	410,160	W/S	0.03263	13,384		
11	Common	336.10.b	1,798,852	CE	0.03263	58,699		
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		3,104,941			783,058		
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	262.i	754,577	W/S	0.03263	24,623		
14	Highway and vehicle	262.i	59,439	W/S	0.03263	1,940		
15	PLANT RELATED							
16	Property	262.i	3,375,510	GP	0.09342	315,346		
17	Gross Receipts	262.i	161,730	NA	zero	0		
18	Other	262.i	245,903	GP	0.09342	22,973		
19	Payments in lieu of taxes		0	GP	0.09342	0		
20	TOTAL OTHER TAXES (sum lines 13 - 19)		4,597,159			364,884		
	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)) =		35.16%					
	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)		-491,112					
25	Income Tax Calculation = line 22 * line 28		5,189,948	NA		292,432		
26	ITC adjustment (line 23 * line 24)		-755,557	NP	0.05612	-42,401		
27	Total Income Taxes	(line 25 plus line 26)	4,434,391			250,031		
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		14,762,402	NA		831,800		
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		32,282,018			2,836,166		

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities

SUPPORTING CALCULATIONS AND NOTES

Line No.				
	TRANSMISSION PLANT INCLUDED IN ISO RATES			Transmission Plant Grandfathered with Joint Plants from VRB00I 6,220,244
1	Total transmission plant (page 2, line 2, column 3)		43,901,418	
2	Less transmission plant excluded from ISO rates (Note M)		6,220,244	
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)		37,681,174	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.85831	
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)		5,841,797	
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0	
8	Included transmission expenses (line 6 less line 7)		5,841,797	
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	0.85831	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.85831	

WAGES & SALARY ALLOCATOR (W&S)

		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.18.b	435,844	0.00	0				
13	Transmission	354.19.b	316,687	0.86	271,817				
14	Distribution	354.20.b	3,777,852	0.00	0				
15	Other	354.21,22,23.b	1,816,142	0.00	0				
16	Total (sum lines 12-15)		6,346,525		271,817	=	0.04283	= WS	Wages & salaries by others for excluded facilities MEC, OTP, MDU
							0.04990	= Wsact	

COMMON PLANT ALLOCATOR (CE) (Note O)

			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	391,601,730	0.76189	*	0.04283	=	0.03263
18	Gas	200.3.d	122,382,899					
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		513,984,634					

RETURN (R)

		$
21	Long Term Interest (117, sum of 56c through 60c)	$0
22	Preferred Dividends (118.29c) (positive number)	$ -
	Development of Common Stock:	
23	Proprietary Capital (112.14d)	0
24	Less Preferred Stock (line 28)	0
25	Less Account 216.1 (112.12d) (enter negative)	0
26	Common Stock (sum lines 23-25)	0

		$	%		Cost (Note P)		Weighted	
27	Long Term Debt (112, sum of 16d through 19d)	787,553,303.7500	0.4890	0.0000	0.0625	0.0000	0.0306	=WCLTD
28	Preferred Stock (112.3d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
29	Common Stock (line 26)	823,024,639.2300	0.5110	0.0000	0.1125	0.0000	0.0575	
30	Total (sum lines 27-29)	##############		0.0000	0.0000	0.0000	0.0881	=R

REVENUE CREDITS

				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			154,370
32	b. Bundled Sales for Resale included in Divisor on page 1			154,370
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$92,695
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$223,060
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$154,941
37	Total of (a)-(b)			$68,119

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. ipial Plant Transmission Facilities

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.

Transmission Revenue Requirement Adjustments

HEARTLAND CONSUMERS POWER DISTRICT 3-Apr-09
INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT
December 31, 2007

MBPP TRANSMISSION FACILITIES

Line	Description	Cost of Service Amount	
1.	Transmission Plant Investment	$7,290,954.06	Page 3, Line L50+Page 5 Line T48
2.	Less Accumulated Depreciation & IDC	($4,953,519.55)	Page 3, Lines M50,N50 + Page 5 Lines U48,V48
3.	General Plant - Trans Share	$175,963.11	Page 3, Line L52 + Page 5 Line T49
4.	Less Accum Depre & IDC-GP-Trans	($94,605.69)	Page 3, Lines M52,N52 + Page 5 Lines U49,V49
5.	Materials & Supplies - Trans	$0.00	Page 2, Lines C88,F88
6.	Cash Working Capital	$10,137.06	1/12 of Line 16 + 17 (this page)
7.	Transmission Investment Rate Base	$2,428,928.99	
8.			
9.	Rate of Return * 6.57%	$159,580.63	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense	$303,319.65	Page 3, Line P50 + Page 5, Line X48
11.	GP Depr Expense - Trans Share	$5,795.01	Page 3, Line P52 + Page 5, Line X49
12.	GP Maintenance	$0.00	Page 1, Lines C42,F42
13.	Income Tax	$0.00	Page 1, Lines C47,F47
14.	Taxes Other than Income	$23,257.83	Page 1, Lines C52,C54,F52,F54
15.	A & G Expenses	$383,034.24	Page 2, Lines C66, F66
16.	Transmission O & M	$218,449.07	Page 2, Lines C73,F73
17.	Less:Trans of Elect by Others	($96,804.36)	Page 2, Lines C82,F82
18.	Subtotal Transmission Revenue Requirement	$996,632.08	
19.			
20.	Annual Trans Third Party Payment	$0.00	
21.	Annual Trans Third Party Revenue	$0.00	
22.			
23.	Total MBPP Transmission Revenue Requirement	$996,632.08	

TRANSMISSION PROJECTS 1 AND 3 FACILITIES (PREVIOUSLY APPROVED IS FACILITIES)

Line	Description	Cost of Service Amount	
24.	Transmission Plant Investment **	$1,292,610.66	Page 4, Line L66,L69
25.	Less Accumulated Depreciation & IDC **	($506,322.24)	Page 4, Lines M66,69,N66,69
26.	General Plant - Trans Share	$111,025.93	Page 4, Line L80
27.	Less Accum Depre & IDC-GP-Trans	($75,299.91)	Page 4, Lines M80,N80
28.	Materials & Supplies - Trans	$0.00	Page 2
29.	Cash Working Capital	$2,815.06	1/12 of Line 39 + 40 (this page)
30.	**Transmission Investment Rate Base**	**$824,829.50**	
31.			
32.	Rate of Return * 6.57%	$54,191.30	Line 30 x Line 32 rate (this page)
33.	Transmission Depr Expense **	$31,033.66	Page 4, Line P66,P69
34.	GP Depr Expense - Trans Share	$4,822.01	Page 4, Line P80
35.	GP Maintenance	$2,989.98	Page 1, Line C41
36.	Income Tax	$0.00	Page 1, Line C47
37.	Taxes Other than Income	$6,471.72	Page 1, Lines C51,C53,C55,C56
38.	A & G Expenses	$66,307.70	Page 2, Line C65
39.	Transmission O & M	$33,780.69	Page 2, Line C71,C72,C74
40.	Less:Trans of Elect by Others	$0.00	Page 2, Line C83
41.	**Subtotal Transmission Revenue Requirement**	**$199,597.06**	
42.			
43.	Annual Trans Third Party Payment	$0.00	
44.	Annual Trans Third Party Revenue	$14,599.01	Revenues from MAPP Schedule F
45.			
46.	**Total Transmission Project 1 and 3 Revenue Requirement**	**$184,998.05**	

<u>INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT</u> **<u>$1,181,630.13</u>** Line 23 + 46 (this page)

* Weighted Cost of Capital
** Doesn't include HCPD's TP-II or LRS Investment

Basin Electric Power Cooperative
Revenue Requirement Adjustment

Adjustment for Inclusion of Third Party Payment for Transmission Service

Adjustment Period - 18 Months Prior to 5/20/2008

Includes the entire period of the Rate Effective May 1, 2008
Includes the entire period of the Rate Effective May 1, 2007
Includes 161 days of the Rate Effective May 1, 2006

		Third Party Payments	Total Revenue Requirement Adjustment
Rate Effective 5/1/2008	100.00%	224,112.00	$224,112.00
Rate Effective 5/1/2007	100.00%	224,112.00	$224,112.00
Rate Effective 5/1/2006	44.11%	224,112.00	$98,855.80
			$547,079.80

Reduction to Annual Transmission Revenue Requirement $547,079.80

Western Area Power Administration

Revenue Requirement Adjustment

Adjustment for Rent from Electrical Property FERC Account 454 Revenue

Adjustment Period - 18 Months Prior to 2/24/2009

Includes the entire period of the Rate Effective May 1, 2008
Includes 250 days of the Rate Effective May 1, 20073

		Rent from Electrical Property Revenue	Total Revenue Requirement Adjustment
Rate Effective 5/1/2008	100.00%	86,366.64	$86,366.64
Rate Effective 5/1/2007	68.49%	93,627.12	$64,125.21
			$150,491.85

Reduction to Annual Transmission Revenue Requirement $150,491.85