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

DEC 2 7 2011

Dear Transmission Customers and Other Interested Parties:

Summarized below are the Integrated System (IS) Transmission and Ancillary Services Rates which will be effective January 1, 2012. Western hosted a meeting providing customers the opportunity to discuss and comment on these recalculated rates on September 29, 2011. Western has considered the comments received in writing or at that meeting in the implementation of these rates. The data used in calculating these rates can be found at either of the following web sites: http://www.wapa.gov/ugp/rates/default.htm or http://www.oatioasis.com/wapa/index.html.

The recalculated 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 $156,624,144.
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $2.77/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 3.79 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$45.95/tag/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.06/kWmonth
Regulation and Frequency Response	UGP-AS3	$0.05/kWmonth
Energy Imbalance	UGP-AS4	i) For deviations within +/- 1.5% (minimum of 2 MW) of the scheduled transaction, 100% of average incremental cost;

		ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of incremental cost when energy taken is greater than energy scheduled and 90% of incremental cost when energy taken is less than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW) of the scheduled transaction, 125% of incremental cost when energy taken is greater than energy scheduled and 75% of incremental cost when energy taken is less than scheduled.
Spinning/Supplemental Reserves	UGP-AS5 and 6	$0.18/kWmonth of customer load
Generator Imbalance	UGP-AS7	i) For deviations within +/- 1.5% (minimum of 2 MW) of the scheduled transaction, 100% of the average incremental cost; ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of incremental cost when energy delivered is less than generation scheduled and 90% of incremental cost when energy delivered is greater than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW)of the scheduled transaction, 125% of incremental cost when energy delivered is less than energy scheduled and 75% of incremental cost when energy delivered is greater than scheduled. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.

Penalty Rate for Unreserved Use of Transmission Service	UGP-TSP1	200% of the transmission service rate for point-to-point service assessed as follows: the penalty for a single hour will be based upon the rate for daily firm point-to-point service; the penalty for more than one assessment of a given duration (e.g. daily) will increase to the next longest duration (e.g. weekly); the penalty charge for multiple instances of unreserved use within a day will be based on the rate for daily firm point-to-point service; the penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service; and the penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

The IS Transmission Loss Factor effective January 1, 2012, is 4 percent and unchanged from the previous 4-year period.

These new rates shall be used in transmission bills calculated on or after February 1, 2012. Please refer to the IS OASIS page (http://www.oatioasis.com/wapa/index.html) for information regarding the implementation status for Western charging Transmission Customers under the Energy Imbalance and Generator Imbalance rates.

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

Sincerely,

Lloyd A. Linke
Operations Manager

bcc:
R. Klinefelter, A0200, Lakewood, CO
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Integrated System Transmission and Ancillary Services Rate Calculation

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

Effective January 1, 2012

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective January 1, 2012

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective Janaury 1, 2012

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$51,718,527	Basin Electric Revenue Requirement Template
5	Western	$107,732,241	Western Revenue Requirement Template
6	Heartland	$888,923	Heartland Revenue Requirement Template
7		$160,339,691	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$3,902,748	MRES Revenue Requirement Template
12		$3,271,795	NWPS Revenue Requirement Template
13		$7,174,543	
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$167,514,234	L7 + L13
19			
20	**2010 True-up Amount**		
21		($10,883,748)	2010 Rate True-up Worksheet
22			
23	**2010 Unreserved Use of Transmission Service Penalties**		
24			
25		($6,342)	
26			
27	**Annual Revenue Requirement for IS Transmission Service after True-up**		
28			
29		$156,624,144	L18 - L21 - L25

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2012

Line No.			Notes
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$156,624,144	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	**IS Transmission System Total Load**		
9			
10		4,710,000 KW	IS Transmission System Total Load Estimate
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15	**$2.77 / KW-Mo**		L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2012

Line No.			Notes
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$2.77 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**3.79 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2012

A.	Fixed Charge Rate	22.585%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$17,380,888	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,925,474	(A x B)
D.	2010 Number of Daily Tags	85,424	
E.	**Rate for Scheduling, System Control and Dispatch Service ($/tag/day)**	**$45.95**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2012 Rate.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (38.65%) and communication facilities plant (68.75%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2010 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 2012
(INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,874,486	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,874,486	(A+B)
D.	Under Collection for 2010	$280,212	(3)
E.	Total Reactive Revenue Requirement with 2010 True-up	$3,154,698	(C+D)
F.	2010 IS Transmission System Total Load (kW-Yr)	4,625,000	(4)
G.	Annual Reactive Charge ($/kW-Yr)	$0.68	(E/F)
H.	Monthly Reactive Charge ($/kW-Mo)	$0.06	(G/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2012, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth

(3) True-up Required for 2010 "True-up for 2010 Reactive Supply and Voltage Control from Generation Sources"

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2012

A.	Western Regulation Revenue Requirement	$1,682,619	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$65,981	(2)
C.	Total Regulation Revenue Requirement	$1,748,600	(A + B)
D.	Under Collection - 2010 Regulation Revenue Rqmt	$66,894	(3)
E.	Total Regulation Revenue Rqmt with True-up	1,815,494	(C+D)
F.	Load in Control Area(s) (kW-Yr)	2,953,000	(4)
G.	Regulation Charge ($/kW-Yr)	$0.61	(E / F)
H.	Regulation Charge ($/kW-Mo)	$0.05	(G / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2012, Western's Costs".

(2) Basin Electric cost support data.

(3) Over/Under Collection "True-up of Regulation and Frequency Response Rate for 2010"

(4) Average of monthly peaks for 2010 IS Customer Control Area.

Rate for Reserves for 2012

A.	Fixed Charge Rate	17.421%	(1)
B.	Generation Net Plant Costs	$ 477,379,201	(2)
C.	Annual Cost of Generation	$ 83,164,231	(A x B)
D.	Plant Capacity (kW)	2,420,000	
E.	Cost/kW ($/kW-Yr)	$ 34.37	(C / D)
F.	Monthly Charge ($/kW-mo)	$ 2.86	(E / 12 months)
G.	Western's Load (kW-Yr)	1,575,000	(3)
H.	Capacity used for Reserves (kW)	98,000	(4)
I.	Annual Reserves Revenue Requirement	$ 3,368,260	(E x H)
J.	Annual Charge ($/kW-Yr)	$ 2.14	(I /G)
K.	Monthly Charge ($/kW-mo)	$ 0.18	(J/12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2012 Rate.

(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 2010.

(4) Southwest Power Pool Reserve Sharing System.

Integrated System Load Data

2012 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

4,710

2010 IS Transmission System Total Load Ancillary Services
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	**01/07/10**	1900	4,662	488	5,150
2	**02/10/10**	800	4,464	499	4,963
3	**03/02/10**	800	3,980	494	4,474
4	**04/08/10**	800	3,418	501	3,919
5	**05/24/10**	1700	3,691	476	4,167
6	**06/30/10**	1700	4,165	476	4,641
7	**07/27/10**	1700	4,624	476	5,100
8	**08/09/10**	1700	4,665	476	5,141
9	**09/01/10**	1700	3,581	476	4,057
10	**10/29/10**	800	3,694	476	4,170
11	**11/23/10**	800	4,299	476	4,775
12	**12/31/10**	1800	4,472	476	4,948
13					
14	**12 CP**		4,143	482	4,625

2010 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 7, 2010	19:00	3364 MW	102 MW	3466 MW
February 10, 2010	8:00	3241 MW	95 MW	3336 MW
March 2, 2010	8:00	2868 MW	82 MW	2950 MW
April 8, 2010	8:00	2395 MW	65 MW	2460 MW
May 24, 2010	17:00	2591 MW	76 MW	2667 MW
June 30, 2010	17:00	2701 MW	97 MW	2798 MW
July 27, 2010	17:00	2932 MW	99 MW	3031 MW
August 9, 2010	17:00	2965 MW	107 MW	3072 MW
September 1, 2010	17:00	2433 MW	68 MW	2501 MW
October 29, 2010	8:00	2603 MW	73 MW	2676 MW
November 23, 2010	8:00	3099 MW	93 MW	3192 MW
December 31, 2010	18:00	3192 MW	97 MW	3289 MW
Total		34,384	1054	35,438
			Average Control Area Load	2,953

(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

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 126,118,760
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		7,091,261	NA	1.00000	7,091,261
3	Non-Firm Point-to-Point Transmission Service Credit		9,236,176	NA	1.00000	9,236,176
4	Revenue from Existing Transmission Agreements		1,874,000	NA	1.00000	1,874,000
5	Scheduling, System Control, and Dispatch Service Credit		106,000	NA	1.00000	106,000
6	Account No. 454	(page 3, line 36)	79,082	TP	1.00000	79,082
7	Account No. 456	(page 3, line 39)	0	TP	1.00000	0
8	TOTAL REVENUE CREDITS					18,386,519
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ 107,732,241

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.	(1)	(2) ROOs Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Note A)					
1	Production	Schedule 1A Total	960,298,305	NA		
2	Transmission	Schedule 1A Total	1,126,787,076	TP	1.00000	1,126,787,076
3	Distribution	Schedule 1A Total	31,991,519	NA		
4	General & Intangible	Bal Sheet - Other Assets - SGL 175002		W/S	1.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		2,119,076,900	GP=	53.173%	1,126,787,076
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	544,771,394	NA		
8	Transmission	Schedule 4	539,770,355	TP	1.00000	539,770,355
9	Distribution	Schedule 4	15,241,878	NA		
10	General & Intangible	Bal Sheet - Other Assets - SGL 175902	0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		1,099,783,627			539,770,355
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	415,526,911			
14	Transmission	(line 2- line 8)	587,016,721			587,016,721
15	Distribution	(line 3 - line 9)	16,749,641			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		1,019,293,273	NP=	57.591%	587,016,721
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.57591	0
21	Account No. 283 (enter negative)		0	NP	0.57591	0
22	Account No. 190		0	NP	0.57591	0
23	Account No. 255 (enter negative)		0	NP	0.57591	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE	(Note C)	0	TP	1.00000	0
	WORKING CAPITAL (Note D)					
26	CWC	calculated	19,682,128			0
27	Materials & Supplies (Note C)	Bal Sheet - Other Assets - SGL 151191	0	TE	0.00000	0
28	Prepayments	Bal Sheet Other Assets	0	GP	0.53173	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		19,682,128			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,038,975,401			587,016,721

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.	(1)	(2) Results of Operation Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note E)	Schedule 11				
1a	Western UGP		53,941,125	PTP/UGP	0.95461	51,492,737
1b	Western RMR		38,546,529	PTP/RMR	0.00925	356,555
1c	COE	COE Financial Stmts	37,352,000	PTP/COE	0.03783	1,413,026
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		18,165,979	PTP/UGP	0.95461	17,341,425
3b	Western RMR		9,451,391	PTP/RMR	0.00925	87,425
4	Less FERC Annual Fees		0	W/S	1.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note G)		0	W/S	1.00000	0
5a	Plus Transmission Related Reg. Comm. Exp (Note G)		0	TE	0.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		157,457,024			70,691,168
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		27,240,010	PTP/UGP	0.95461	26,003,586
9b	Western RMR		14,220,442	PTP/RMR	0.00925	131,539
9c	COE		10,870,848	PTP/COE	0.03783	411,244
10	General		0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		52,331,300			26,546,369
	TAXES OTHER THAN INCOME TAXES (Note H)					
	LABOR RELATED					
13	Payroll		0	W/S	1.00000	0
14	Highway and vehicle		0	W/S	1.00000	0
15	PLANT RELATED					
16	Property		0	GP	0.53173	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.53173	0
19	Payments in lieu of taxes		0	GP	0.53173	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note I)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote I.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.57591	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		51,117,590	NA		28,881,223
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		260,905,914			126,118,760

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN IS RATES							
1	Total transmission plant (page 2, line 2, column 3)						1,126,787,076	
2	Less transmission plant excluded from IS rates (Note K)							
3	Less transmission plant included in OATT Ancillary Services (Note L)						0	
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)						1,126,787,076	
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)					TP=	1.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)							
7	Less transmission expenses included in OATT Ancillary Services (Note J)						0	
8	Included transmission expenses (line 7 less line 6)						0	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.00000	
10	Percentage of transmission plant included in IS Rates (line 5)					TP	1.00000	
11	Percentage of transmission expenses included in IS Rates (line 9 times line 10)					TE=	0.00000	
	WAGES & SALARY ALLOCATOR (W&S)	$	TP	Allocation				
12	Production	0	0.00	0				
13	Transmission	18,907,420	1.00	18,907,420				
14	Distribution	0	0.00	0			W&S Allocator	
15	Other		0.00	0			($ / Allocation)	
16	Total (sum lines 12-15)	18,907,420		18,907,420		=	1.00000	
	PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)	$						
17	Transmission Plant In Service UGP	1,083,478,852						
18	Total Plant In Service UGP	1,135,000,426						
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)			PTP/UGP		=	0.95461	
20	Transmission Plant in Service RMR	6,323,513						
21	Total Plant In Service RMR	683,875,642						
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)			PTP/RMR		=	0.00925	
23	Transmission Plant in Service COE	36,984,711						
24	Total Plant In Service COE	977,752,962						
25	COE Percentage of Transmission Plant to Total Plant (line 23 divided by line 24)			PTP/COE		=	0.03783	
	COMMON PLANT ALLOCATOR (CE) (Note N)	$		% Electric (line 17 / line 20)			Labor Ratio (line 16)	= CE
26	Electric	0						0.00000
27	Gas	0		0.00000		*	1.00000	
28	Water	0						
29	Total (sum lines 17-19)	0						
	RETURN (R)	$						
30	Long Term Interest Schedule 5	$37,434,238						

Line No.			$	%	Cost (Note O)	Weighted	=WCLTD
		HFD Sch's 21RX & 21X Col 8 Lines					
31	Long Term Debt	23,25,26,29,30	760,936,643	100%	0.0492	0.0492	=R
32	Proprietary Capital			0%	0.1238	0.0000	
33	Total (sum lines 22-23)		760,936,643	100%		0.0492	
34					Proprietary Capital Cost Rate =	12.38%	
35					TIER =	1.00	

Line No.			
	REVENUE CREDITS		Load
	ACCOUNT 447 (SALES FOR RESALE)		
36	a. Bundled Non-RQ Sales for Resale	(Note P)	0
37	b. Bundled Sales for Resale included in Divisor on page 1		0
38	Total of (a)-(b)		0
39	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)		79,082
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)		
40	a. Transmission charges for all transmission transactions		
41	b. Transmission charges for all transmission transactions included in Divisor on page 1		
42	Total of (a)-(b)		$0

Revenue Requirement - Non-Levelized | Revenue Requirement Template Utilizing Financial Statement Results of Operations | Est for 12 Months Ending 9/30/2012

Western Area Power Administration

General Note: References to Results of Operations in this revenue requirement template indicate the Financial Statement Results of Operations (ROOs) Schedule where data is located

Note Letter	
	To the extent the references to ROOs data are missing, the entity will include a "Notes" section to provide this data.
A	Combines plant data for both the Upper Great Plains Region and Rocky Mountain Region.
B	Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in 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.
C	Transmission related only.
D	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 in the Other Assets Section of the Balance Sheet
E	For O&M Expense, Calculated as Total O&M from Results of Operations less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from Schedule 11, plus CME and Warehouse Interest from Schedule 5. Depreciation Expense from Results of Operations Schedule 4.
F	Totals of Results of Operations Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1421, 1422, 1425, 1426, 1431, 1432, 1441, 1442
G	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.
H	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.
I	Western is not subject to Federal or State Income Tax.

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

J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates.
K	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).
L	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.
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.
N	Western does not have Common Plant.
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
P	Line 29 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.
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not inlcuded in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template.

Western's Ancillary Services Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2012
(WESTERN'S COSTS)

A.	Fixed Charge Rate	17.421%	(1)
B.	Generation Net Plant Costs ($)	$477,379,201	(2)
C.	Annual Cost of Generation ($)	$83,164,231	(A x B)
D.	Capability Used for Reactive Support (%)	3.46%	(3)
E.	Reactive Service Revenue Requirement	$2,874,486	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2012 Rate.

(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 2006-2010.

TRUE-UP FOR 2010 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES (INTEGRATED SYSTEM)

A.	WAPA 2010 Rate Reactive Service Revenue Requirement	$2,376,635	(1)
B.	WAPA 2010 Actual Reactive Service Revenue Requirement	$2,874,486	(2)
C.	Under Collection of Revenue Requirement	($497,851)	(A-B)
D.	2010 Rate IS Transmission System Total Load (kW-Yr)	4,237,000	(3)
E.	2010 Actual IS Transmission System Total Load (kW-Yr)	4,625,000	(4)
F.	Difference 2010 Rate Load to 2010 Actual Load	(388,000)	(D-E)
F.	Under collection of revenue requirement	($497,851)	(C)
G.	Over collection due to volume	$217,639	(F * [A/D] * -1)
17 H.	Net Under Collection	($280,212)	(F+G)

(1) Reactive Service Revenue Requirement from "Rate for Reactive Supply and Voltage Control from Generation Sources For 2008, Western's Costs".

(2) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2012, Western's Costs".

(3) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2008, Western's Costs".

(4) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2012, Western's Costs".

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2010 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,376,635	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,376,635	(A+B)
D.	2008 IS Transmission System Total Load (kW-Yr)	4,237,000	(3)
E.	Annual Reactive Charge ($/kW-Yr)	$0.56	(C/D)
F.	Monthly Reactive Charge ($/kW-Mo)	$0.05	(E/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2008, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth

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

REGULATION AND FREQUENCY RESPONSE FOR 2012
(Western's Costs)

A.	Fixed Charge Rate	15.733%	(1)
B.	Corps Generation Net Plant Costs ($)	$169,705,389.00	(2)
C.	Annual Corps Generation Cost ($)	$26,699,748.85	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	$28.49	(C / D)
F.	Capacity Used for Regulation (kW)	59,060	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$1,682,619	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$1,682,619	
J.	Load in Control Area(s) (kW-Yr)	2,953,000	(4)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2012 Rate.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/10.

(3) Cost of Purchases Required to Regulate for Intermittent Resources

(4) Average of monthly peaks for 2010 Watertown Control Area.

TRUE-UP OF REGULATION AND FREQUENCY RESPONSE FOR 2010 RATE (INTEGRATED SYSTEM)

A.	2010 Rate Regulation Service Revenue Requirement	$1,362,791	(1)
B.	2010 Actual Regulation Service Revenue Requirement	$1,748,600	(2)
C.	Under Collection of Revenue Requirement	($385,809)	(A-B)
D.	2010 Rate Load in Control Area(s) (kW-Yr)	2,393,000	(3)
E.	2010 Actual Load in Control Area(s)(kW-Yr)	2,953,000	(4)
F.	Difference 2010 Rate Load to 2010 Actual Load	(560,000)	(D-E)
F.	Under collection of revenue requirement	($385,809)	(C)
G.	Over collection due to volume	$318,915	(F * [A/D] * -1)
H.	Net Under Collection	($66,894)	(F+G)

(1) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2008".

(2) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2012".

(3) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2008".

(4) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2012".

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2010

		2010 Rate	
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.

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	$76,153,933	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$649,554,071	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	11.724%	L4/L6
9			
10			
11	B. A&G Expense for Generation		
12			
13	Generation A&G Expense	$322,646	A&G Expenses Worksheet, C6L18
14			
15	Net Generation Plant Investment	$649,554,071	L6
16			
17	A&G as % of Net Generation Plant Investment	0.050%	L13/L15
18			
19			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	$14,207,631	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$649,554,071	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.187%	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	3.460%	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	11.724%	L8
47			
48	A&G Expense	0.050%	L17
49			
50	Depreciation Expense	2.187%	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	3.460%	L41
57			
58	Total	17.421%	
59			
60			
61	H. Generation Revenue Requirement		
62			
63	Generation Fixed Charge Rate	17.421%	L58
64			
65	Net Generation Plant Investment	$649,554,071	L6
66			
67	Western Annual Generation Revenue Requirement	$113,158,815	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	$40,365,971	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$411,120,510	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	9.819%	L4/L6
9			
10			
11	B. A&G Expense for Corps Generation		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L18
14			
15	Net Corps Generation Plant Investment	$411,120,510	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	$10,090,794	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$411,120,510	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.454%	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	3.460%	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	9.819%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.454%	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	3.460%	L41
57			
58	Total	15.733%	
59			
60			
61	H. Corps Generation Revenue Requirement		
62			
63	Corps Generation Fixed Charge Rate	15.733%	L58
64			
65	Net Corps Generation Plant Investment	$411,120,510	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$64,681,590	L63 * L65
68			

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	$53,634,174	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$53,634,174	L4 + L5
7			
8	Net Transmission Plant Investment	$536,341,657	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	10.000%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$15,777,403	A&G Expenses Worksheet, C6L16
16			
17	Net Transmission Plant Investment	$536,341,657	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.942%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$23,452,678	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$536,341,657	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.373%	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	5.270%	Cost of Capital Worksheet, C6L9
44			
45			
46	G. Transmission Fixed Charge Rate		
47			
48	Operation and Maintenance Expense	10.000%	L10
49			
50	A&G Expense	2.942%	L19
51			
52	Depreciation Expense	4.373%	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	5.270%	L43
59			
60	Total	22.585%	
61			
62			
63	H. Transmission Revenue Requirement		
64			
65	Transmission Fixed Charge Rate	22.585%	L60
66			
67	Net Transmission Plant Investment	$536,341,657	L8
68			
69	Annual Western-UGPR Transmission Cost	$121,132,763	L65 * L67
70			
71			
72			
73			

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**	228,535,365	81,863,584			310,398,949
3						
4	Less:					
5	**Other Power Supply Expenses**	158,145,689	35,742,861			193,888,550
6	**A&G Expenses**	16,482,532	8,924,963			25,407,495
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	0	0			0
9						
10	Plus:					
11	**Moveable Property Interest**	618,902	196,695			815,597
12	**Warehouse Stores Interest**	93,728	71,129			164,857
13						
14	**COE/BOR Total**			41,644,456	34,718,780	76,363,236
15	**PS Total O&M**	54,619,774	37,463,584	41,644,456	34,718,780	168,446,594
16						
17	**PS-ED Transmission O&M 5/**	52,011,024	344,665	1,278,485	0	53,634,174
18						
19	**PS-ED Generation O&M 6/**	1,069,182	0	40,365,971	34,718,780	76,153,933

1/ All Western UGPR O&M Expenses are from the FY 2010 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 2010 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 2010 Corps of Engineers Financial Statements.

4/ Total BOR O&M Expenses are from the FY 2010 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.

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	2,713,363	1,762,287	0	0	4,475,650
3	1412	1,998,079	2,491,927	0	0	4,490,006
4	1415	15,306	5,608	0	0	20,914
5	1416	18,594	10,285	0	0	28,879
6	1421	1,304,381	856,406	0	0	2,160,787
7	1422	1,681,032	6,391	0	0	1,687,423
8	1425	4,141	575	0	0	4,716
9	1426	15,306	0	0	0	15,306
10	1431	0	0	0	0	0
11	1432	(276)	0	0	0	(276)
12	1441	5,134,930	2,899,681	0	0	8,034,611
13	1442	3,597,676	891,803	0	0	4,489,479
14	**PS Total A&G**	16,482,532	8,924,963	0	0	25,407,495
15						
16	**PS-ED Transmission A&G 4/**	15,695,293	82,110	0	0	15,777,403
17						
18	**PS-ED Generation A&G 5/**	322,646	0	0	0	322,646

1/ Western UGPR A&G Expenses are from the FY 2010 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 2010 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.

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	24,155,989 1/	14,220,442 2/	10,410,393 3/	3,643,984 4/	52,430,808
3						
4	PS-ED Transmission Depreciation 5/	23,002,251	130,828	319,599	0	23,452,678
5						
6	PS-ED Generation Depreciation 6/	472,853	0	10,090,794	3,643,984	14,207,631

1/ FY 2010 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2010 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2010 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR, COE, 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.

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.

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 2010 Balances	667,366,399	1/	406,291,036	1/	533,352,475	1/	109,694,352	1/	1,716,704,262	
4											
5	**Interest Expenses:**										
6	FY 2010 Interest	34,526,487	13/	24,717,027	13/	16,797,334	2/	4,427,942	2/	80,468,790	
7	Average Interest Rate	5.174%	L6/L3	6.084%	L6/L3	3.149%	L6/L3	4.037%	L6/L3		
8	Transmission Plant Factor	0.9937	3/	0.0063	4/	0.0286	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.270%	7/
10	Generation Plant Factor	0.0147	8/	0.0000	9/	0.6683	10/	0.3170	11/		
11	Weighted Gen. Composite Rate									3.460%	12/

1/ FY 2010 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2010 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33, 33A and ROOs Schedule 5.
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).
13/ Interest from Results of Operations Schedule 5

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	1,045,919,863	1/	683,875,642	2/	958,959,462	3/	440,835,098	12/	3,129,590,065
3	PS-ED Transmission Plant-in-Service	995,964,899	4/	6,323,513	5/	29,480,711	6/	0		1,031,769,123
4	PS-ED Generation Plant-in-Service	20,474,302	7/	0		929,478,751	L2-L3	440,835,098	L2-L3	1,390,788,151
5	Generation Plant to Total Plant	0.019575	L4/L2	0.0000	L4/L2	0.9693	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.952238	L3/L2	0.0092	L3/L2	0.0307	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	500,397,629	8/	273,066,358	9/	534,775,860	10/	213,080,555	11/	1,521,320,402
9	PS-ED Trans. Accumulated Depreciation	476,497,637	L6*L8	2,512,210	L6*L8	16,417,619	L6*L8	0	L6*L8	495,427,466
10	PS-ED Gen. Accumulated Depreciation	9,795,284	L5*L8	0	L5*L8	518,358,241	L8-L9	213,080,555	L5*L8	741,234,080
11	PS-ED Net Transmission Plant	519,467,262	L3-L9	3,811,303	L3-L9	13,063,092	L3-L9	0	L3-L9	536,341,657
12	PS-ED Net Generation Plant	10,679,018	L4-L10	0	L4-L10	411,120,510	L4-L10	227,754,543	L4-L10	649,554,071

1/ Transmission Plant-in-Service Worksheet, C2L512.
2/ FY 2010 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2010 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L512.
5/ Transmission Plant-in-Service Worksheet, C5L521.
6/ Transmission Plant-in-Service Worksheet, C5L525.
7/ Transmission Plant-in-Service Worksheet, C4L512.
8/ FY 2010 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2010 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2010 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2010 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2010 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.

Line No.	(1) DESCRIPTION a	(2) FY2010 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	8,061,211			8,061,211	
9	BROOKINGS-SIOUX FALLS	1,174,861			1,174,861	
10	BROOKINGS-WATERTOWN NO. 1	1,718,240			1,718,240	
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	1,259,668			1,259,668	
14	CHARLIE CREEK-BELFIELD	14,511,242			14,511,242	
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	918,676			918,676	
22	DAWSON-WILLISTON	1,258,900			1,258,900	
23	DENISON-CRESTON	12,947,827			12,947,827	
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	6,914,811			6,914,811	
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	7,554,492			7,554,492	
39	FORT RANDALL-FORT THOMPSON 1&2	7,359,619			7,359,619	
40	FORT RANDALL-GAVIN'S POINT	1,151,719			1,151,719	
41	FORT RANDALL-GREGORY	777,327			777,327	
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	8,505,957			8,505,957	
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	10,536,015			10,536,015	
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	1,813,500			1,813,500	
54	GRANITE FALLS- MORRIS	3,279,089			3,279,089	
55	GRANITE FALLS-MINNESOTA VALLEY	156,778			156,778	
56	GREAT FALLS-CONRAD	12,747,013			12,747,013	
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	5,772,742			5,772,742	

Line No.	(1) DESCRIPTION a	(2) FY2010 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	10,808,503			10,808,503	
64	HURON-MT VERNON	617,623			617,623	
65	HURON-WATERTOWN 230KV 1&3	5,792,955			5,792,955	
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	16,016,353			16,016,353	
70	JAMESTOWN-VALLEY CITY	1,055,414			1,055,414	
71	LEEDS-DEVILS LAKE	2,323,057			2,323,057	
72	LEEDS-ROLLA	1,609,492			1,609,492	
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 (BEPS)	8,470,654			8,470,654	
78	MILES CITY-BAKER (BEFP)	2,363,768			2,363,768	
79	MILES CITY-CUSTER	3,750,704			3,750,704	
80	NEW UNDERWOOD-PHILIP	2,116,605			2,116,605	
81	NEW UNDERWOOD-RAPID CITY NO 1	1,067,598			1,067,598	
82	NEW UNDERWOOD-RAPID CITY NO. 2	309,991			309,991	
83	NEW UNDERWOOD-STEGALL (HURON)	2,672,947			2,672,947	
84	OAHE-FORT THOMPSON 230KV 1&2	3,149,034			3,149,034	
85	OAHE-FORT THOMPSON 230KV 3&4	5,119,119			5,119,119	
86	OAHE-GLENHAM	5,768,280			5,768,280	
87	OAHE-MAURINE	1,973,555			1,973,555	
88	OAHE-NEW UNDERWOOD	6,447,607			6,447,607	
89	OAHE-PIERRE	388,816			388,816	
90	O'FALLON CREEK-MILES CITY	2,488,318			2,488,318	
91	PIERRE-PHILIP	1,187,034			1,187,034	
92	RAPID CITY-ELK CREEK 115-kV T/L	52,064			52,064	
93	RUGBY-LEEDS	2,235,655			2,235,655	
94	SHELBY-SHELBY#2	576,090			576,090	
95	SIOUX CITY-DENISON	1,661,311			1,661,311	
96	SIOUX CITY-SPENCER	1,938,353			1,938,353	
97	SIOUX FALLS- SIOUX CITY	3,217,192			3,217,192	
98	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	277,897			277,897	
99	SUMMIT-WATERTOWN	6,743,203			6,743,203	
100	TIBER TAP-TIBER	1,084,858			1,084,858	
101	UTICA JCT-SIOUX FALLS	3,485,236			3,485,236	
102	VALLEY CITY-FORMAN	1,527,895			1,527,895	
103	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM	312,931			312,931	
104	WATERTOWN-GRANITE FALLS 1&2	5,269,587			5,269,587	
105	WATERTOWN-SIOUX CITY	26,679,769			26,679,769	
106	WATFORD CITY-BEULAH	1,401,905			1,401,905	
107	WILLISTON-WATFORD CITY	563,079			563,079	
108	WM. J. NEAL-RUGBY	4,629,316			4,629,316	
109	YELLOWTAIL-CUSTER	2,265,163			2,265,163	
110	Subtotal	419,045,953	0	0	419,045,953	
111						
112	Substations					
113	ARMOUR SUBSTATION	1,974,410	(82,000)		1,892,410	
114	ASH SUBSTATION	63,325			63,325	
115	AURORA SUBSTATION	2,899,881			2,899,881	
116	BELDEN SUBSTATION	164,986			164,986	
117	BELFIELD SUBSTATION	10,019,253			10,019,253	
118	BERESFORD SUBSTATION	3,504,976	(595,846)		2,909,130	17% of the costs of this facility have been allocated to distribution.
119	BISBEE SUBSTATION	272,529	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution.
120	BISMARK SUBSTATION	8,135,623			8,135,623	
121	BISON	12,472			12,472	
122	BOLE SUB (BEFP)	92,092			92,092	
123	BOLE SUB (BEPS)	3,111,717			3,111,717	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
124	BONESTEEL SUBSTATION	3,442,909	(1,721,454)		1,721,455	50% of the costs of this facility have been allocated to distribution.
125	BROOKINGS SUBSTATION	4,381,014			4,381,014	
126	CARPENTER SUBSTATION	2,463,312			2,463,312	
127	CARRINGTON SUBSTATION	3,756,722	(488,374)		3,268,348	13% of the costs of this facility have been allocated to distribution
128	CIRCLE SUBSTATION	1,507,470			1,507,470	
129	CONRAD SUB	311,656			311,656	
130	CONRAD SUB (BEPS)	5,008,913			5,008,913	
131	CRESTON SUBSTATION	4,941,437	(55,000)		4,886,437	
132	CROSSOVER SUB (BEFP)	267,232			267,232	
133	CROSSOVER SUB	10,785,373			10,785,373	
134	CULBERTSON EAST SWITCHING STATION	2,000,000			2,000,000	
135	CUSTER SUBSTATION (BEFP)	3,189,684			3,189,684	
136	CUSTER SUBSTATION	1,401,908			1,401,908	
137	CUSTER TRAIL SUBSTATION	1,475,222	(737,611)		737,611	50% of the costs of this facility have been allocated to distribution.
138	DAWSON COUNTY SUBSTATION	10,388,257	(831,061)		9,557,196	8% of the costs of this facility have been allocated to distribution.
139	DENISON SUBSTATION	15,717,046			15,717,046	
140	DEVAUL SUBSTATION	894,977	(536,986)		357,991	60% of the costs of this facility have been allocated to distribution.
141	DEVILS LAKE SUBSTATION	2,591,935	(285,113)		2,306,822	11% of the costs of this facility have been allocated to distribution.
142	EAGLE BUTTE SUBSTATION	1,264,347			1,264,347	
143	EDGELEY SUBSTATION	3,477,612	(486,866)		2,990,746	14% of the costs of this facility have been allocated to distribution.
144	ELK CREEK SUBSTATION	2,089,203			2,089,203	
145	ELLENDALE SUBSTATION	579			579	
146	ENDERLIN TAP STATION	749,768			749,768	
147	EXIRA SWITCHING STATION	5,500,776			5,500,776	
148	FAIRVIEW WEST SWITCHING STATION	4,296,873			4,296,873	
149	FAITH SUBSTATION	1,212,383	(606,191)		606,192	50% of the costs of this facility have been allocated to distribution.
150	FARGO SUBSTATION	20,526,477	(47,000)		20,479,477	
151	FLANDREAU SUBSTATION	3,413,659	(580,322)		2,833,337	17% of the costs of this facility have been allocated to distribution.
152	FORMAN SUBSTATION	5,568,535	(723,910)		4,844,625	13% of the costs of this facility have been allocated to distribution.
153	FORT RANDALL	253,710			253,710	
154	FORT THOMPSON #2	10,324,254			10,324,254	
155	FORT THOMPSON SUBSTATION	15,464,906	(354,000)		15,110,906	
156	GLENDIVE SUBSTATION	1,725,310			1,725,310	
157	GRAND FORKS SUBSTATION	9,386,889			9,386,889	
158	GRAND ISLAND SUBSTATION	11,935,734			11,935,734	
159	GRANITE FALLS SUBSTATION	18,750,220	(57,000)		18,693,220	
160	GREAT FALLS SUB (BEFP)	103,435			103,435	
161	GREAT FALLS SUB	470,826			470,826	
162	GREGORY SUBSTATION	1,530,584	(306,117)		1,224,467	20% of the costs of this facility have been allocated to distribution.
163	GROTON SUBSTATION	5,198,675			5,198,675	
164	HAVRE SUBSTATION	5,644,005	(959,481)		4,684,524	17% of the costs of this facility have been allocated to distribution.
165	HILKEN SUSTATION	3,874,407			3,874,407	
166	HURON SUBSTATION	11,409,760			11,409,760	
167	JAMESTOWN SUBSTATION	18,503,937	(1,850,394)		16,653,543	10% of the costs of this facility have been allocated to distribution
168	KILLDEER SUBSTATION	434,273			434,273	
169	LAKOTA SUBSTATION	2,811,438	(927,775)		1,883,663	33% of the costs of this facility have been allocated to distribution.
170	LEEDS SUBSTATION	1,435,419	(200,959)		1,234,460	14% of the costs of this facility have been allocated to distribution.
171	LETCHER SUBSTATION	10,175,442			10,175,442	
172	MARTIN SUBSTATION	1,533,848			1,533,848	
173	MAURINE SUBSTATION	6,145,220			6,145,220	
174	MIDLAND SUBSTATION	672,772			672,772	
175	MILES CITY SUB #4	1,669,005			1,669,005	
176	MILES CITY #2 (BEFP)	986,001			986,001	
177	MILES CITY SUB #3	4,634,218			4,634,218	
178	MILES CITY SUB #3 (BEFP)	226,697			226,697	
179	MILES CITY SUBSTATION (BEFP)	160,336			160,336	
180	MILES CITY SUBSTATION	714,993			714,993	
181	MISSION SUBSTATION	3,156,994			3,156,994	
182	MORRIS SUBSTATION	7,114,391			7,114,391	
183	MT VERNON SUBSTATION	2,088,281			2,088,281	
184	NELSON SUBSTATION	1,500,000			1,500,000	
185	NEW UNDERWOOD SUBSTATION	9,581,288	(1,053,942)		8,527,346	11% of the costs of this facility have been allocated to distribution.
186	NEWELL SUBSTATION	1,149,585			1,149,585	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
187	Non-Facility	412,629			412,629	
188	O'FALLON CREEK SUBSTATION	2,185,525	(1,092,762)		1,092,763	50% of the costs of this facility have been allocated to distribution.
189	PHILIP SUBSTATION	1,993,110			1,993,110	
190	PIERRE SUBSTATION	4,230,424	(2,115,212)		2,115,212	50% of the costs of this facility have been allocated to distribution.
191	RAINBOW SUBSTATION	723,556			723,556	
192	RAPID CITY SUBSTATION	4,802,395			4,802,395	
193	RICHLAND SUBSTATION	1,623,998	(1,299,198)		324,800	80% of the costs of this facility have been allocated to distribution.
194	ROLLA SUBSTATION	623,513	(155,878)		467,635	25% of the costs of this facility have been allocated to distribution.
195	RUDYARD SUBSTATION	2,585,060	(439,460)		2,145,600	17% of the costs of this facility have been allocated to distribution.
196	RUGBY SUBSTATION	5,886,039	(824,045)		5,061,994	14% of the costs of this facility have been allocated to distribution.
197	SAVAGE SUB	74,403			74,403	
198	SHELBY SUBSTATION	1,084,272			1,084,272	
199	SHELBY SUBSTATION #2 (BEFP)	286,340			286,340	
200	SHELBY SUBSTATION #2 (BEPS)	4,134,102			4,134,102	
201	SIOUX CITY #2	9,444,471			9,444,471	
202	SIOUX CITY SUBSTATION	16,041,266	(57,000)		15,984,266	
203	SIOUX FALLS SUBSTATION	7,403,080			7,403,080	
204	SPENCER	3,240,715			3,240,715	
205	SULLY BUTTES	74,428			74,428	
206	SUMMIT SUBSTATION	2,729,672			2,729,672	
207	TYNDALL SUBSTATION	842,578			842,578	
208	UTICA JCT.	12,863,876			12,863,876	
209	VALLEY CITY SUBSTATION	3,017,303			3,017,303	
210	VERONA	25,210			25,210	
211	VIRGIL FODNESS SUBSTATION	3,206,763			3,206,763	
212	WALL SUBSTATION	1,609,013	(804,506)		804,507	50% of the costs of this facility have been allocated to distribution.
213	WARD SUBSTATION	3,456,032			3,456,032	
214	WASHBURN SUBSTATION	1,972,344			1,972,344	
215	WATERTOWN #2	2,977,436			2,977,436	
216	WATERTOWN STATIC VAR SYSTEM	11,737,397			11,737,397	
217	WATERTOWN SUBSTATION	13,136,814			13,136,814	
218	WATFORD CITY SUB	1,516,413	(30,000)		1,486,413	
219	WESSINGTON SPRINGS SUBSTATION	4,051,147			4,051,147	
220	WHATELY (NORTHERN)	40,860			40,860	
221	WHATELY SUBSTATION	109,910	(54,955)		54,955	50% of the costs of this facility have been allocated to distribution.
222	WHITE 345/115 SUB	9,658,399			9,658,399	
223	WICKSVILLE SUBSTATION	683,282	(341,641)		341,641	50% of the costs of this facility have been allocated to distribution.
224	WILLISTON 2 SUBSTATION	5,795,299			5,795,299	
225	WILLISTON SUBSTATION	6,684,168			6,684,168	
226	WINNER SUBSTATION	3,370,017	(1,685,008)		1,685,009	50% of the costs of this facility have been allocated to distribution.
227	WOLF POINT SUBSTATION	7,230,798	(2,169,239)		5,061,559	30% of the costs of this facility have been allocated to distribution.
228	WOONSOCKET SUBSTATION	2,264,105			2,264,105	
229	YANKTON SUBSTATION	53,583			53,583	
230	Subtotal	489,525,142	(24,692,571)	0	464,832,571	
231						
232	**Line Taps & Related Equipment**					
233	ANITA	6,259			6,259	
234	ASSINNIBOINE	35,005			35,005	
235	BAKER (BEFP)	133,554			133,554	
236	BAKER	97,832			97,832	
237	CANYON FERRY (BEFP)	15,145			15,145	
238	CANYON FERRY	30,065			30,065	
239	CHARLIE CREEK	1,121,015			1,121,015	
240	COTTON	1,399			1,399	
241	DENBIGH TAP	848,872			848,872	
242	DICKINSON	63,736			63,736	
243	E. J. MANNING	49,112			49,112	
244	EAGLE	156,285			156,285	
245	FORSYTH	32,070			32,070	
246	FORSYTH	273,368			273,368	
247	HARLEM	174,745			174,745	
248	HARLEM (BEFP)	16,015			16,015	
249	HETTINGER	4,451			4,451	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
250	HIGHWOOD	22,896			22,896	
251	MALLARD	29,969			29,969	
252	MALTA	164,007			164,007	
253	NASHUA SUB	72,368			72,368	
254	O'NEILL SUB (NPP)	115,790			115,790	
255	PENN TAP	890,607			890,607	
256	PLEASANT LAKE TAP	992,415			992,415	
257	POPLAR (MDU)	3,758			3,758	
258	SHIRLEY TAP	22,102			22,102	
259	STANLEY	49,735			49,735	
260	TERRY TAP	78,497			78,497	
261	TERRY TAP	345,850	(172,925)		172,925	50% of the costs of this facility have been allocated to distribution.
262	TIBER TAP	166,306	(83,153)		83,153	50% of the costs of this facility have been allocated to distribution.
263	VETAL TAP	232,375			232,375	
264	V. T. HANLON	5,553			5,553	
265	WM. J. NEAL	166,336			166,336	
266	YANKTON JCT.	28,526			28,526	
267	ZENITH	2,047			2,047	
268	Subtotal	6,448,066	(256,078)	0	6,191,988	
269						
270	**O&M Service & Maintenance Centers**					
271	ARMOUR O&M SER. CEN.	3,488,667			3,488,667	
272	BISMARCK O&M SER. CEN.	8,975,625			8,975,625	
273	DAWSON SER. CEN.	22,545			22,545	
274	DEVILS LAKE O&M SER. CEN.	3,852,064			3,852,064	
275	Fargo Line Maintenance Facility	2,028,772			2,028,772	
276	FARGO O&M SER. CEN.	794,673			794,673	
277	FORT PECK SER. CEN.	5,793,310			5,793,310	
278	FORT THOMPSON O&M S. C.	315,000			315,000	
279	HAVRE SERVICE CENTER	249,377			249,377	
280	HURON O&M SER. CEN.	2,447,927			2,447,927	
281	JAMESTOWN O&M SER. CEN.	3,841,398			3,841,398	
282	MILES CITY MTCE FAC.	21,817			21,817	
283	MILES CITY MTCE FAC.	1,003,437			1,003,437	
284	NEW UNDERWOOD SER. CEN.	96,884			96,884	
285	PHILIP O&M SER. CENT.	1,690,034			1,690,034	
286	PIERRE O&M SER. CEN.	1,049,030			1,049,030	
287	RAPID CITY GARAGE & STOR.	2,055,932			2,055,932	
288	SIOUX CITY O&M SER. CEN.	3,007,882			3,007,882	
289	SIOUX FALLS O&M SER. CEN.	239,920			239,920	
290	WATERTOWN MAINT. CEN.	934,402			934,402	
291	Subtotal	41,908,696	0	0	41,908,696	
292						
293	**Operation Centers**					
294	WATERTOWN ALTERNATE OPERATIONS CENTER	5,922,871		(2,055,473)	3,867,398	Column 4 shows 34.704% of the Watertown Operations Center that
295	WATERTOWN OPERATIONS CENT	876,061		(304,028)	572,033	was prorated to generation based on FTE associated with generation.
296	WATERTOWN OPER CTR (BFPS)	11,329,841		(3,931,908)	7,397,933	
297	Subtotal	18,128,773	0	(6,291,409)	11,837,364	
298						
299	**Mobile Equipment**					
300	MOB 115KV SWITCH TRAILER	12,328			12,328	
301	MOB 115KV SWITCH TRAILER	57,413			57,413	
302	MOB TRANSF 111KV 15MVA	213,000			213,000	
303	MOB TRANSF 115KV 10MVA	76,258			76,258	
304	MOB TRANSF 115KV 10MVA	142,235			142,235	
305	MOB TRANSF 115KV 25MVA	556,464			556,464	
306	MOB TRANSF 115KV 40MVA	499,220			499,220	
307	MOB TRANSF 230KV 1-33MVA	170,278			170,278	
308	MOBILE BY PASS KIT (BISMARCK)	35,071			35,071	
309	MOBILE BY PASS KIT (HURON)	163,695			163,695	
310	MOBILE CAPACITOR BANK	19,075			19,075	
311	MOBILE SUB 110KV	127,144			127,144	
312	MOBILE SUB 115KV 20MVA	404,166			404,166	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
313	MOBILE SUB 41.6 KV	192,498			192,498	
314	MOBILE SUB 69KV	71,118			71,118	
315	MOB SH REACTOR	179,328			179,328	
316	Subtotal	2,919,291	0	0	2,919,291	
317						
318	**Transmission-Related Generation Facilities**					
319	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
320	CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
321	CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
322	FORT PECK POWERPLANT (COE)	8,380		(8,380)	0	
323	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
324	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
325	Subtotal	1,985,311	0	(1,985,311)	0	
326						
327	**Communication Facilities**					
328	ATLANTIC COMMUNICATION SITE	17,199		(5,447)	11,752	Column 4 shows 31.67% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation.
329	BAKER RELAY	27,791		(8,801)	18,990	
330	BANTRY	268,530		(85,044)	183,486	
331	BARRETT	244,695		(77,495)	167,200	
332	BATTLE MT. MICROWAVE	470,739		(149,083)	321,656	
333	BELLE PRAIRIE	16,111		(5,102)	11,009	
334	BELLE PRAIRIE	577,323		(182,838)	394,485	
335	BENEDICT	36,772		(11,646)	25,126	
336	BEULAH	10,679		(3,382)	7,297	
337	BIG BEND	113,362		(35,902)	77,460	
338	BIJOU REPEATER	562,952		(178,287)	384,665	
339	BISMARCK REPEATER	405,324		(128,366)	276,958	
340	BISON REPEATER	204,957		(64,910)	140,047	
341	BOLE NORTH REPEATER	149,228		(47,260)	101,968	
342	BRINSMADE	237,551		(75,232)	162,319	
343	BRISTOL	11,441		(3,623)	7,818	
344	BRUNSVILLE REPEATER	92,595		(29,325)	63,270	
345	BUFFALO	255,051		(80,775)	174,276	
346	CAHOON	240,466		(76,156)	164,310	
347	CARRINGTON REPEATER	726,855		(230,195)	496,660	
348	CHARTER OAK REPEATER	12,546		(3,973)	12,546	
349	CHARTER OAK REPEATER	3,121		(988)	3,121	
350	CHINOOK (BEFP)	284,048		(89,958)	194,090	
351	CHINOOK REPEATER	15,293		(4,843)	10,450	
352	CLARK MW REPEATER	588,027		(186,228)	401,799	
353	CLEVELAND REPEATER, N.D.	263,617		(83,488)	180,129	
354	COLEMAN REPEATER	105,281		(33,342)	71,939	
355	COLOME REPEATER	469,005		(148,534)	320,471	
356	CONRAD BUTTE REPEATER	371,283		(117,585)	253,698	
357	CONRAD BUTTE REPEATER	84,384		(26,725)	57,659	
358	CRESTON REPEATER	11,107		(3,517)	7,590	
359	CROW LAKE REPEATER	311,803		(98,748)	213,055	
360	CROWN BUTTE	202,445		(64,114)	138,331	
361	CULBERTSON RADIO RELAY SITE	1,926		(610)	1,316	
362	CUSTER LOOKOUT	194,017		(61,445)	132,572	
363	DALTON (WES)	198,021		(62,713)	135,308	
364	DEVILS LAKE REPEATER	467,927		(148,192)	319,735	
365	DODSON REPEATER	276,812		(87,666)	189,146	
366	DOGDEN BUTTE	281,286		(89,083)	192,203	
367	DRISCOLL	196,774		(62,318)	134,456	
368	DUPREE REPEATER	1,821		(577)	1,244	
369	DUTTON REPEATER (BEPS)	18,529.82		(5,868)	12,662	
370	DUTTON REPEATER (BEFP)	315,739		(99,995)	215,744	
371	EAST RAINY BUTTE	287,339		(91,000)	196,339	
372	ECKELSON	288,401		(91,337)	197,064	
373	ELKTON	146,696		(46,458)	100,238	
374	ELLENDALE REPEATER	644,579		(204,138)	440,441	
375	ELLSWORTH AIR BASE	59,669		(18,897)	40,772	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
376	ERHARD	301,774		(95,572)	206,202	
377	EXIRA REPEATER	2,527		(800)	1,727	
378	F. L. BLAIR	104,176		(32,993)	71,183	
379	FAIRPOINT REPEATER	339,030		(107,371)	231,659	
380	FALLON REPEATER	271,939		(86,123)	185,816	
381	FERGUS FALLS COMMUNICATIONS SITE	485,567		(153,779)	331,788	
382	FLOWING WELLS	68,763		(21,777)	46,986	
383	FORBES COMMUNICATION SITE	45,316		(14,352)	30,964	
384	FORT PECK RELAY (WES)	250,960		(79,479)	171,481	
385	FORT THOMPSON REPEATER	306,861		(97,183)	209,678	
386	FORT THOMPSON REPEATER (EAST RIVER)	301,614		(95,521)	206,093	
387	FOX CREEK MICROWAVE	579,063		(183,389)	395,674	
388	FRYBURG SUB & MICROWAVE	210,967		(66,813)	144,154	
389	GARRISON	249,702		(79,081)	170,621	
390	GARY REPEATER	228,494		(72,364)	156,130	
391	GAVIN'S POINT	149,584		(47,373)	102,211	
392	GAVINS POINT REPEATER	411,445		(130,305)	281,140	
393	GETTYSBURG REPEATER	290,839		(92,109)	198,730	
394	GLENHAM	293,701		(93,015)	200,686	
395	GRAND FORKS MINNKOTA (MPC)	23,847		(7,552)	16,295	
396	HAILSTONE BUTTE	188,523		(59,705)	128,818	
397	HALLOWAY REPEATER	266,614		(84,437)	182,177	
398	HATHAWAY	17,314		(5,483)	11,831	
399	HATHAWAY	191,777		(60,736)	131,041	
400	HERMOSA MICROWAVE	302,701		(95,865)	206,836	
401	HIGHLAND REPEATER	177,964		(56,361)	121,603	
402	HIGHMORE REPEATER	251,511		(79,654)	171,857	
403	HINSDALE	201,837		(63,922)	137,915	
404	HINSDALE REPEATER	25,153		(7,966)	17,187	
405	HOPEWELL REPEATER	391,934		(124,126)	267,808	
406	HUNTER MICROWAVE	307,546		(97,400)	210,146	
407	HURON DISTRICT OFFICE	747,055		(236,592)	510,463	
408	HYSHAM	250,143		(79,220)	170,923	
409	JAMESTOWN REPEATER	46,981		(14,879)	32,102	
410	JONES CREEK	251,034		(79,502)	171,532	
411	KELLY CREEK	15,210		(4,817)	10,393	
412	KELLY CREEK	300,278		(95,098)	205,180	
413	KILLDEER REPEATER	395,542		(125,268)	270,274	
414	KNEE HILL MW	308,285		(97,634)	210,651	
415	KNEE HILL MW	119,303		(37,783)	81,520	
416	KONES CORNER REPEATER	470,207		(148,915)	321,292	
417	LAC QUI PARLE	747,619		(236,771)	510,848	
418	LAKE ANDES REPEATER	648,460		(205,367)	443,093	
419	LEFOR	186,943		(59,205)	127,738	
420	LINDSAY RIDGE	235,489		(74,579)	160,910	
421	LINTON COMMUNICATIONS SITE	339,867		(107,636)	232,231	
422	LODGEPOLE REPEATER	186,559		(59,083)	127,476	
423	MALTA REPEATER	289,599		(91,716)	197,883	
424	MANDAN MICROWAVE SITE	69,988		(22,165)	47,823	
425	MAPLE RIVER	172,792		(54,723)	118,069	
426	MARTIN REPEATER	287,916		(91,183)	196,733	
427	MAYVILLE	331,361		(104,942)	226,419	
428	MIDLAND REPEATER	660,339		(209,129)	451,210	
429	MILES CITY SUB (BEFP)	305,418		(96,726)	208,692	
430	MOE REPEATER	129,266		(40,939)	88,327	
431	MOORHEAD	251,422		(79,625)	171,797	
432	MORRIS REPEATER & MICROWAVE	331,303		(104,924)	226,379	
433	NEWCASTLE REPEATER	216,330		(68,512)	147,818	
434	OAHE	564,580		(178,803)	385,777	
435	O'KREEK REPEATER	508,754		(161,122)	347,632	
436	ORCHARD REPEATER	43,642		(13,821)	29,821	
437	OTO MICROWAVE	16,445		(5,208)	11,237	
438	OTTUMWA ROAD REPEATER SITE	7,685		(2,434)	5,251	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
439	PAGE N.D.	1,646		(521)	1,125	
440	PAHOJA SUB	66,444		(21,043)	45,401	
441	PEAK	264,351		(83,720)	180,631	
442	PHILIP JCT. REPEATER	545,125		(172,641)	372,484	
443	PINE RIDGE	15,766		(4,993)	10,773	
444	PINE RIDGE	273,894		(86,742)	187,152	
445	PRIMGHAR REPEATER	11,990		(3,797)	8,193	
446	PUKWANNA REPEATER	258,360		(81,823)	176,537	
447	RAPID CITY REPEATER	354,281		(112,201)	242,080	
448	RICHARDSON COULEE	214,752		(68,012)	146,740	
449	RICHARDSON COULEE REPEATER	24,536		(7,771)	16,765	
450	RICHLAND MW REPEATER (BEPS)	444,616		(140,810)	303,806	
451	ROCKY RIDGE REPEATER	226,934		(71,870)	155,064	
452	ROLLAG	172,922		(54,764)	118,158	
453	RUGBY REPEATER	276,659		(87,618)	189,041	
454	RUTLAND	388,869		(123,155)	265,714	
455	SACO	1,237		(392)	845	
456	SENTINEL BUTTE	215,321		(68,192)	147,129	
457	SHEEP COULEE REPEATER	475,744		(150,668)	325,076	
458	SIOUX CITY REPEATER	576,462		(182,566)	393,896	
459	SIOUX FALLS REPEATER	367,833		(116,493)	251,340	
460	SIOUX PASS	1,366		(433)	933	
461	SNAKE BUTTE REPEATER	729,560		(231,052)	498,508	
462	SPALDING REPEATER	38,651		(12,241)	26,410	
463	SPIRIT MOUND	226,293		(71,667)	154,626	
464	STRASBERG	17,870		(5,659)	12,211	
465	SUMMIT REPEATER	50,053		(15,852)	34,201	
466	TAPPEN COMMUNICATIONS SITE	291,767		(92,403)	199,364	
467	TAPPEN REPEATER	272,393		(86,267)	186,126	
468	TENNANT COMMUNICATIONS SITE	8,782		(2,781)	6,001	
469	TORONTO REPEATER	106,096		(33,601)	72,495	
470	TRIPP REPEATER	114,817		(36,363)	78,454	
471	TURKEY RIDGE REPEATER	633,181		(200,529)	432,652	
472	TYLER REPEATER	449,771		(142,443)	307,328	
473	VICTOR (EREC)	35,530		(11,252)	24,278	
474	VIDA	14,357		(4,547)	9,810	
475	VIDA	323,156		(102,343)	220,813	
476	WALL REPEATER	461,034		(146,010)	315,024	
477	WATERTOWN REPEATER	699,939		(221,671)	478,268	
478	WAYSIDE	118,156		(37,420)	80,736	
479	WESSINGTON SPGS. REPEATER	624,746		(197,857)	426,889	
480	WESTFIELD	19,003		(6,018)	12,985	
481	WHITE SWAN	116,529		(36,905)	79,624	
482	WHITLOCK (BCPS)	165,594		(52,444)	113,150	
483	WOLBACH REPEATER	28,280		(8,956)	19,324	
484	YELLOWTAIL SWITCHYARD (BEPS)	343,984		(108,940)	235,044	
485	Subtotal	38,514,629	0	(12,197,582)	26,317,047	
486						
487	**Miles City Converter Station**					
488	MILES CITY CONVERTER STATION - BEPS	20,983,258			20,983,258	
489	MILES CITY CONVERTER STATION - BEFP	1,928,730			1,928,730	
490	Subtotal	22,911,988	0	0	22,911,988	
491						
492	**Distribution Facilities**					
493	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	650,001	(650,001)		0	
494	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	These facilities have been determined to be used solely for distribution
495	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	and are therefore not recovered in the transmission rate
496	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
497	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
498	FORT PECK-WOLF POINT	190,500	(190,500)		0	
499	FRAZER PUMP SUB	253,597	(253,597)		0	
500	GARRISON-SNAKE CREEK	569,241	(569,241)		0	
501	GLENDIVE P.P. #1 SUB	425,706	(425,706)		0	

Line No.	(1) DESCRIPTION a	(2) FY2010 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
502	INTAKE SUBSTATION	108,040	(108,040)		0	
503	INTAKE-INTAKE PUMP	6,494	(6,494)		0	
504	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
505	SHIRLEY PUMP SUBSTATION	127,053	(127,053)		0	
506	SNAKE CREEK PUMP SUBSTATI	662,435	(662,435)		0	
507	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
508	TIBER DAM SUBSTATION	318,568	(318,568)		0	
509	WIOTA SUBSTATION	38,507	(38,507)		0	
510	**Subtotal Distribution Facilities**	4,532,014	(4,532,013)	0	1	
511						
512	**Subtotal Upper Great Plains Region Facilities**	1,045,919,863	(29,480,662)	(20,474,302)	995,964,899	
513						
514						
515						
516	**Rocky Mountain Region Facilities**					
517	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2010 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.
518	STEGALL SUBSTATION	8,932,478	(8,629,869)		302,609	
519	STEGALL-WAYSIDE	2,978,205			2,978,205	
520	YELLOWTAIL SWITCHYARD	11,019,451	(8,264,588)		2,754,863	
521		23,217,970	(16,894,457)	0	6,323,513	
522						
523	**Corps of Engineers Facilities**					
524	CORPS SWITCHYARD FACILITIES	35,219,147		(5,738,436)	29,480,711	
525		35,219,147	0	(5,738,436)	29,480,711	
526						
527	**TOTAL FACILITIES**	1,104,356,980	(46,375,119)	(26,212,738)	1,031,769,123	

Basin Electric's Transmission Cost Data

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

Projections for 2012

Line No.			Total		Allocator	Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ 84,938,398	$ 51,334,094	$ 9,392,868	$ 24,211,368
	(MBPP West Excluded - 1-.065997)							$ 8,772,967	
	REVENUE CREDITS								
2	Third Party Receipts			TP	1.00000		$ (333,000)	$ -	$ -
3									
4	Third Party Payments			TP	1,00000		$ 97,532		
5		(line 2 + 4)					$ (235,468)	$ -	$ -
6	NET REVENUE REQUIREMENT	(line 1 + 5)					$ 51,098,626	$ 619,901	$ 24,211,368
7	TOTAL REVENUE REQUIREMENT WITH MBPP EAST						$ 51,718,527		

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

Projections for 2012

	(1)	(2) Worksheets	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B			(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE (Note A)											
1	Production	Worksheet 1, L1, C, d	4,013,343,130	NA	0.000%	-	NA	0.000%				
2	Transmission	Worksheet 1, L2, C.d	717,350,000	DA	100.000%	717,350,000	DA	100.000%		428,840,769	93,581,195	194,928,036
3	Distribution		-	NA	0.000%	-	NA	0.000%		-	-	-
4	General	Worksheet 1, L3, C, d	147,772,000									
4a	Direct Assign - Transmission (Note B)		41,377,662	DA	100.000%	41,377,662	DA	100.000%		34,065,318	4,129,409	3,182,935
4b	Direct Assign - Production		38,388,859	NA	0.000%	-	NA	0.000%		-	-	-
4c	Other		68,005,479	WS	9.435%	6,416,317	GP	Gross Plant	GP1	3,835,754	837,034	1,743,506
5	Intangible	Worksheet 1, L4, C, d	73,332,740	DA	100.000%	69,082,416	DA	100.000%		32,102,757	2,617,629	34,362,020
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	Worksheet 1, L5, C.d	$ 4,951,797,870			$ 834,226,395				$ 498,844,608	$ 101,165,267	$ 234,216,457
				GP			GP	Gross Plant	GP1	59.781%	13.045%	27.173%
	ACCUMULATED DEPRECIATION											
7	Production	Worksheet 1, L6, C, d	1,211,981,268	NA	0.000%		NA	0.000%		-	-	-
8	Transmission	Worksheet 1, L7, C, d	292,977,227	DA	100.000%	292,977,227	DA	100.000%		189,770,889	53,267,500	49,938,838
9	Distribution		-	NA	0.000%		NA	0.000%				
10	General	Worksheet 1, L8, C, d	113,279,662									
10a	Direct Assign - Transmission		22,493,164	DA	100.000%	28,760,846	DA	100.000%		23,281,447	3,202,875	2,276,524
10b	Direct Assign - Production		37,529,692	NA	0.000%		NA	0.000%				
10c	Other		53,256,806	WS	9.435%	5,024,780	GP	Gross Plant	GP1	3,003,864	655,483	1,365,383
11	Intangible	Worksheet 1, L9, C, d	50,451,514	DA	100.000%	49,451,514	DA	100.000%		22,535,495	1,952,304	24,963,725
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	Worksheet 1, L10, C, d	$ 1,668,689,671			$ 376,214,367				$ 238,591,685	$ 59,078,162	$ 78,544,470
	NET PLANT IN SERVICE											
13	Production	(line 1- line 7)	2,801,361,862	AUTO		-	AUTO			-	-	-
14	Transmission	(line 2- line 8)	424,372,773	AUTO		424,372,773	AUTO			239,069,880	40,313,695	144,989,198
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO			-		
16	General	(line 4 - line 10)	34,492,338	AUTO		-	AUTO			-		
16a	Direct Assign	(line 4a - line 10a)	18,884,498	AUTO		12,616,816	AUTO			10,783,871	926,534	906,411
16b	Production	(line 4b - line 10b)	859,167	AUTO		-	AUTO			-		
16c	Other	(line 4c - line 10c)	14,748,673	AUTO		1,391,537	AUTO			831,890	181,551	378,123
17	Intangible	(line 5 - line 11)	22,881,226	AUTO		19,630,902	AUTO			9,567,282	865,325	9,398,295
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 3,283,108,199			$ 458,012,026				$ 260,252,923	$ 42,067,105	$ 155,672,027
	WORKING CAPITAL											
19	CWC (Note C)	one eighth of line 9, page 3	10,542,656	DA	100.000%	4,418,062	DA	100.000%		2,826,011	626,394	965,649
20	Materials & Supplies Transmission	Estimate based on 2010 actual	6,000,000	GP	100.000%	6,000,000	GP	Gross Plant	GP1	3,586,660	782,700	1,630,380
21	Prepayments (Note C)		-	GP	Gross Plant	-	GP	Gross Plant	GP1	-	-	-
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 16,542,656			$ 10,418,062				$ 6,412,871	$ 1,409,094	$ 2,596,029
23	Rate Base		$ 3,299,650,855			$ 468,430,090				$ 266,665,794	$ 43,496,199	$ 158,268,056

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

Projections for 2012

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B			(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
	O&M											
1	Transmission less Account 565	Expense Worksheet #3, L 7&16, C.b	27,776,538									
2	Direct Assignment (Note D)	Accounting Records	13,717,510	DA	100.000%	13,717,510	DA	100.000%		9,048,447	3,559,871	1,109,192
3	Other	Accounting Records	14,059,028	TPW	100.000%	14,059,028	TPW	(page 4)	GP2	9,665,582	-	4,393,446
4	A&G	Expense Worksheet #3, L11, C.b	56,564,713			-						
5	Less Regulatory Fees (Note E)	Accounting Records	250,000	NA	0.000%	-	NA	0.000%				
6	Production	Accounting Records	2,287,130	NA	0.000%	-	NA	0.000%				
7	Transmission (Note F)	Accounting Records	1,476,226	DA		1,476,226	DA	100.000%		252,362	656,614	567,250
8	Headquarters		52,551,357	WS	9.435%	6,091,731	GP	Gross Plant	GP1	3,641,698	794,666	1,655,306
9	TOTAL O&M (sum lines 1 and 4)		$ 84,341,251			$ 35,344,495				$ 22,608,089	$ 5,011,151	$ 7,725,194
	DEPRECIATION & AMORTIZATION EXPENSE											
10	Depreciation and Amortization Expense	Accounting Records	101,546,619									
11	Transmission	Accounting Records	12,818,123	DA	100.000%	12,818,123	DA	100.000%		6,648,272	1,260,547	4,909,304
12	Production	Accounting Records	88,728,496	NA	0.000%		NA	0.000%				
13	General Plant	Accounting Records	11,994,667	NA	0.000%		NA	0.000%				
14	Transmission	Accounting Records	1,829,606	DA	100.000%	1,829,606	DA	100.000%		1,561,106	187,761	80,739
15	Production	Accounting Records	6,500,000	NA	0.000%	-	NA	0.000%				
16	Other General Plant		3,665,061	WS	9.435%	345,799	GP	Gross Plant	GP1	206,722	45,109	93,964
17	Other Amortization		1,927,673	DA	100.000%	1,899,262	DA	100.000%		903,295	65,397	930,570
18	TOTAL (Sum lines 10,13,17)	Expense Worksheet #3, L20, C.b	$ 115,468,959			$ 16,892,790				$ 9,319,395	$ 1,558,814	$ 6,014,577
	TAXES OTHER THAN INCOME TAXES											
19	PLANT RELATED											
20	Property total			NA	0.000%	-	NA	0.000%				
21	Tax Reclassification	Accounting Records	2,300,000	DA	100.000%	2,300,000	DA	Estimated		2,100,000	-	200,000
22	Gross Receipts (Note G)	Estimated		NA	0.000%	-	NA	0.000%		-	-	-
23	Production											
24	TOTAL OTHER TAXES		$ 2,300,000			$ 2,300,000				$ 2,100,000	$ -	$ 200,000
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 202,110,210			$ 54,537,285				$ 34,027,484	$ 6,569,965	$ 13,939,771
26	Return (page 2, line 23, column 3 * wcc)	WCC	$ 214,147,340	WCC	Rate Base	$ 30,401,113	WCC	Rate Base		$ 17,306,610	$ 2,822,903	$ 10,271,597
27	REV. REQUIREMENT (sum lines 25+26)		$ 416,257,550			$ 84,938,398				$ 51,334,094	$ 9,392,868	$ 24,211,363

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A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent			(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
									$223,234	$457,562	$194,928,036
1	Production	Accounting Records	50,196,392								
2	Transmission-East	Accounting Records	223,234								
3	Transmission-West	Accounting Records	457,562	WS	Trans % of total wages	9.435%	Gross Plant	GP1	59.781%	13.045%	27.173%
4	Transmission-Allocated	Accounting Records	4,548,485								
5	Distribution		-	TPW	Trans % excluding West			GP2	68.750%	0.000%	31.250%
6	Other Transmission		-								
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$55,425,673								

Transmission Wage and Salary Dollar Split

Line #				
8	IS transmission Plant (p.2,c.6.L2)	428,840,769		
9	West (MBPP) Transmission Plant (p.2..c.7.L2)	93,581,195		
10	Other transmission Plant (p.2.c.8.L2)	194,928,036		
11		$717,350,000		
12			68.750%	
13			31.250%	
14			100.000%	GP2

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Note I

Weighted Cost of Capital

			Percent	Rate	Weighted cost
Wksht #1	LTD	3,017,075,000	74.57%	5.00%	3.73%
Wksht #1	Equity	1,028,845,000	25.43%	10.85%	2.76%
		4,045,920,000	100.00%		6.49%

A RUS form 12h plus new investment averaged over 13 months.
B General Plant directly assigned to transmission includes the transmission maintenance buildings and microwave assigned to transmission.
C Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3 , line 9, column 6-8.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, in the RUS 12.
D Includes Lease payments of $4,140,536.94 for member facilities in the IS system and O&M that is charged to specific lines or substations.
E Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings.
F A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages.
Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.
G SD Gross receipts taxes paid in lieu of property with a portion directly assigned to other transmission.
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.
H West (MBPP) plant (93,581,195) is excluded in the percentage calculations on line 12 and 13 as costs for transmission and A&G are directly allocated to MBPP.
I Equity percent as a percent of total estimated long term debt plus current portion of long term debt plus equity.

Basin Electric Power Cooperative

Worksheet #1

Work Paper

Line		a Actual 2010	b Estimated Budget Year 2011	c Estimated Budget Year 2012	d Transmission Adjusted for 2012 Average Balance
	GROSS PLANT IN SERVICE				
1	Production	2,082,757,697	3,733,000,000	4,293,686,260	4,013,343,130
2	Transmission	658,499,042	716,700,000	718,000,000	717,350,000
3	General	136,072,681	142,772,000	152,772,000	147,772,000
4	Intangible	78,022,312	73,332,740	73,332,740	73,332,740
5	TOTAL GROSS PLANT	$ 2,955,351,732	$ 4,665,804,740	$ 5,237,791,000	$ 4,951,797,870
	ACCUMULATED DEPRECIATION				
6	Production	1,073,423,957	1,164,135,124	1,259,827,412	1,211,981,268
7	Transmission	271,542,242	285,797,227	300,157,227	292,977,227
8	General	95,677,219	108,524,633	118,034,690	113,279,662
9	Intangible	47,082,041	49,328,356	51,574,671	50,451,514
10	TOTAL ACCUM. DEPR	$ 1,487,725,459	$ 1,607,785,340	$ 1,729,594,000	$ 1,668,689,670
	NET PLANT IN SERVICE				
11	Production	1,009,333,740	2,568,864,876	3,033,858,848	2,801,361,862
12	Transmission	386,956,800	430,902,773	417,842,773	424,372,773
13	General	40,395,462	34,247,367	34,737,310	34,492,339
14	Intangible	30,940,271	24,004,384	21,758,069	22,881,227
15	TOTAL NET PLANT	$ 1,815,294,289	$ 3,058,019,400	$ 3,508,197,000	$ 3,283,108,200

	2012 Estimate
Long-term Liabilities	
Long-term debt, net of current portion	$ 2,929,161,000
Obligations under capital lease	
Total Long-term Liabilities	$ 2,929,161,000
Current Liabilities	
Current portion of long-term debt	$ 87,914,000
Total LTD	3,017,075,000
Equity	1,028,845,000

Basin Electric Power Cooperative
Integrated System Facilities (IS)

IS Facilities Worksheet #2

IS Facilities			12/31/10 Gross Plant	12/31/10 Accum Depr	12/31/10 Net Book Value	2010 Depreciation Expense	12/31/11 Gross Plant	12/31/11 Accum Depr	12/31/11 Net Book Value	2011 Depreciation Expense	12/31/12 Gross Plant	12/31/12 Accum Depr	12/31/12 Net Book Value	2012 Depreciation Expense
IS Lines			249,444,419	129,823,169	119,621,250	3,173,182	249,444,419	132,996,351	116,448,068	3,173,182	249,444,419	134,582,941.68	114,861,477.69	3,173,182
IS Substations			119,186,037	61,517,577	57,668,460	1,794,487	119,186,037	63,312,063	55,873,973	1,794,487	119,186,037	64,209,306.81	54,976,729.75	1,794,487
IS Trans Mntnce Bldgs			17,917,146	13,071,635	4,845,511	748,115	17,917,146	13,819,750	4,097,396	748,115	17,917,146	14,193,807.02	3,723,339.00	748,115
IS Microwave			10,778,172	8,099,367	2,678,805	544,492	10,778,172	8,643,859	2,134,313	544,492	10,778,172	8,916,104.45	1,862,067.35	544,492
Intangible			32,120,916	21,168,763	10,952,153	911,148	32,120,916	22,079,911	10,041,005	911,148	32,120,916	22,535,485.24	9,585,430.76	911,148
Accum Depr Adjustment				(10,786,702)				(10,786,702)				(10,786,702)		
Total			429,446,690	222,893,809	206,552,881	7,171,423	429,446,690	230,065,232	199,381,458	7,171,423	429,446,690	233,650,943	195,795,747	7,171,423
Williston-Tioga 230 kV Line	12/31/10	24,400,000	527,686	-	527,686	-	24,308,318	653,967	23,654,351	653,967	24,308,318	980,951	23,327,367	653,967
Williston Substation Transformers	12/31/10	2,700,000		-	-	-	2,700,000	74,250	2,625,750	74,250	2,700,000	111,375	2,588,625	74,250
Sully Buttes Reactor	03/08/11	1,430,000					1,430,000	32,771	1,397,229	32,771	1,430,000	52,433	1,377,567	39,325
Watford City 230/115 kV Transformer	06/01/11	200,000					200,000	3,208	196,792	3,208	200,000	5,958	194,042	5,500
C Creek Sub & 345/230 kV Transformer	11/01/11	8,850,000					8,850,000	40,563	8,809,438	40,563	8,850,000	162,250	8,687,750	243,375
Glenham Shunt Reactor	02/01/11	4,500,000					4,500,000	113,438	4,386,563	113,438	4,500,000	175,313	4,324,688	123,750
Miscellaneous General Plant Additions	07/01/11	1,100,000					1,100,000	27,500	1,072,500	27,500	1,100,000	55,000	1,045,000	55,000
Charlie Creek Cap Banks	12/01/11	3,000,000					3,000,000	6,875	2,993,125	6,875	3,000,000	48,125	2,951,875	82,500
ND/SD Microwave	12/01/11	4,270,000					4,270,000	9,785	4,260,215	9,785	4,270,000	116,535	4,153,465	213,500
Miscellaneous Upgrades	12/01/11	1,700,000					1,700,000	3,896	1,696,104	3,896	1,700,000	27,271	1,672,729	46,750
230/115 Transformer, Caps, etc. Philip	01/31/12	5,300,000									3,261,538	66,802	3,194,736	133,604
Switches - Witten	01/01/12	200,000									200,000	2,750	197,250	5,500
Western ND capacitors	01/01/12	4,000,000									3,692,308	55,000	3,637,308	110,000
Mission Area Capacitors	01/01/12	2,000,000									1,846,154	27,500	1,818,654	55,000
Broadland transformer	11/30/12	5,900,000									907,692	6,760	900,932	13,521
Blaisdell 230/115 Sub	08/31/12	9,350,000									3,596,154	42,854	3,553,300	85,708
			527,686	-	527,686	-	52,058,318	966,253	51,092,065	966,253	65,562,164	1,936,878	63,625,286	1,941,251
GRAND TOTAL			429,974,376	222,893,809	207,080,567	7,171,423	481,505,008	231,031,485	250,473,523	8,137,676	495,008,854	235,587,821	259,421,033	9,112,673

West (MBPP)		12/31/10 Gross Plant	12/31/10 ACCUM DEPR	12/31/10 Net Book Value	2010 Depreciation Expense	12/31/11 Gross Plant	12/31/11 ACCUM DEPR	12/31/11 Net Book Value	2011 Depreciation Expense	12/31/12 Gross Plant	12/31/12 ACCUM DEPR	12/31/12 Net Book Value	2012 Depreciation Expense
West (MBPP) Lines		70,749,575	41,688,953	29,060,622	910,642	70,749,575	42,144,274	28,605,301	910,642	70,749,575	42,599,595	28,149,980	910,642
West (MBPP) Substations		19,780,420	11,803,062	7,977,358	259,005	19,780,420	11,932,565	7,847,856	259,005	19,780,420	12,062,067	7,718,353	259,005
West (MBPP) Trans Mntnce Bldgs		2,296,936	1,745,696	551,240	93,165	2,296,936	1,792,279	504,657	93,165	2,296,936	1,838,861	458,075	93,165
West (MBPP) Microwave		1,832,472	1,269,418	563,054	94,596	1,832,472	1,316,716	515,756	94,596	1,832,472	1,364,014	468,458	94,596
Intangible		2,617,629	1,886,907	730,722	65,397	2,617,629	1,919,605	698,024	65,397	2,617,629	1,952,304	665,325	65,397
Accum Depr Adjustment			(1,443,108)				(1,443,108)			-	(1,443,108)		-
Total		97,277,032	56,950,928	40,326,104	1,422,805	97,277,032	57,662,331	39,614,702	1,422,805	97,277,032	58,373,733	38,903,299	1,422,805
Miscellaneous Additions/replacements	12/01/11	-	-	-	-	3,051,200	3,496	3,047,704	6,992	3,051,200	48,946	3,002,254	90,900
			-	-	-								
GRAND TOTAL		97,277,032	56,950,928	40,326,104	1,422,805	100,328,232	57,665,827	42,662,405	1,429,798	100,328,232	58,422,680	41,905,553	1,513,706

Basin Electric Power Cooperative

Expense Worksheet #3

		(a) 2011 Estimate	(b) 2012 Estimated
	Expenses - Operations:		
1	Production - Excluding Fuel	87,903,501	108,356,465
2	Production - Fuel	215,572,718	244,630,035
3	Production - Rents	38,996,062	39,854,657
4	Other Power Supply	321,273,588	310,883,506
5	**Sub-Total Operations Exp.**	663,745,869	703,724,663
6			
7	Transmission Operations	20,512,300	22,903,038
8	Trans of Electricity by others	36,643,475	22,672,810
9	Subtotal - Transmission	57,155,775	45,575,848
10			
11	Administration	51,897,524	56,564,713
12	**Total Operations Expense**	772,799,168	805,865,224
13			
14	**Expenses - Maintenance:**		
15	Production	136,108,310	127,010,329
16	Transmission	4,731,553	4,873,500
17	General Plant	0	0
18	**Total Maintenance Expense**	140,839,863	131,883,829
19			
20	Depreciation & Amortization	92,889,743	115,455,209
21	Taxes	2,576,472	3,581,591
22	Interest & Other Deductions	72,248,181	140,147,864
		167,714,396	259,184,664
	Total Cost of Electric Service	**1,081,353,427**	**1,196,933,717**

Basin Electric Power Cooperative
Lines
December 31, 2010

cpx	Type	Description	Book Basis Amount	Accum Depr_LTD	Net Book Amount	Depr_YTD
012	L	230kv LO#1 DC Line to Washburn	1,485,282	1,450,404	34,878	-
021	L	345 kv line Stanton to SD border	9,297,594	8,214,053	1,083,541	26,842
022	L	345 kv line - SD to Ft Thompson	9,134,431	7,849,188	1,285,244	25,089
023	L	345 kv line Stanton to SD border	11,511,850	10,051,512	1,460,338	31,822
024	L	345 kv line SD to Watertown	10,164,504	8,667,492	1,497,012	32,443
025	L	230 kv line LOS#1 to Logan	5,181,912	3,832,986	1,348,927	31,078
026	L	230 kv line-230/115/69-sub (16)	289,132	250,117	39,015	1,259
031	L	115 kv line Logan to Kenmare	3,115,809	2,222,008	893,801	15,614
032	L	115 kv line Logan to Mallard	632,973	436,680	196,293	3,052
034	L	230 kv line Philip Tap-Philip Sub	853,709	767,616	86,093	2,419
127	L	345 kv N line #1 dbl circ	12,442,227	5,071,157	7,371,070	218,976
128	L	345 kv S line #2 dbl circ	11,215,381	5,545,076	5,670,305	161,916
129	L	500 kv AVS switchyd to SD border	57,926,565	29,270,039	28,656,526	852,932
130	L	500 kv SD bdr to Broadland sub	53,098,066	26,721,017	26,377,048	778,666
134	L	345 kv dbl circ line	942,053	641,501	300,552	10,018
141	L	230 kv line Broadland to Huron	1,068,625	566,153	502,471	16,505
150	L	230 kv line Estavan to Sask border	15,071,877	10,517,013	4,554,864	119,132
152	L	345 kv line AVS to Charlie Creek	11,657,031	6,112,826	5,544,205	156,831
181	L	230 KV Line - Rhame to Belfield	28,291,157	552,421	27,738,735	552,421
185	L	230 kv line MC-Bowman-NU	9,481,900	7,742,275	1,739,625	271,110
234	L	115Kv Line-Char Ck-Sqw Gab Sub	1,218,283	70,670	1,147,613	33,507
235	L	115Kv Line-Sqw Gap-ND/MT border	375,853	20,833	355,021	10,416
236	L	115Kv Line-ND/MT Brd-Richld Sb	281,424	16,137	265,287	7,746
296	L	230 kv line - Williston to Tioga	527,686	-	527,686	-
311	L	115 kv tie line to Groton sub	136,010	93,077	42,933	1,431
361	L	69KV Line Cornbelt	41,112	8,152	32,960	1,200
411	L	230 KV Line RC to New Underwood	6,010,877	1,041,782	4,969,095	142,952
		Total Lines	**261,453,325**	**137,732,187**	**123,721,138**	**3,505,378**

Basin Electric Power Cooperative
Substations
December 31, 2010

cpx	Type	Description	Book Basis Amount	Accum Depr_LTD	Net Book Amount	Depr_YTD
013	S	230KV LO Washburn Substation	71,594	70,298	1,296	-
016	S	230/115/69KV LO Substation	1,234,995	1,145,325	89,670	2,800
036	S	345KV FT Thompson Substation	2,374,699	2,055,764	318,934	10,631
039	S	230/115KV Storla, SD Substation	2,207,566	1,837,515	370,051	12,087
040	S	230/115KV Philip, SD Substation	862,865	743,659	119,206	3,973
042	S	230KV Philip,SD Tap Substation	214,957	195,414	19,544	613
046	S	Martin, SD USBR Sub Capacitor Installed	200,287	153,087	47,200	1,573
047	S	Armour, SD USBR Sub Capacitor Installed	137,379	124,792	12,587	420
058	S	115KV Williston, ND Substation	643,259	474,572	168,687	5,623
060	S	230/115KV Dickinson, ND Substation	1,204,038	1,089,017	115,021	3,651
061	S	115KV Spirit Mound Switchyard	1,555,594	1,197,568	358,026	11,100
063	S	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,967	1,474,094	173,872	52,163
126	S	500KV Broadland SD, Substation	12,470,254	6,592,730	5,877,524	194,672
142	S	230KV USBR Huron Substation Addition	1,712,166	876,149	836,017	26,484
145	S	Manning,ND Sub Capacitor Installed	186,623	154,800	31,823	1,591
153	S	345/115KV Charlie Creek Substation	5,342,496	3,735,499	1,606,997	52,055
179	S	Little Missouri Tap 115 kv Capacitor Bank	1,244,509	39,961	1,204,547	34,253
182	S	230 kv Belfield Substation	25,722	531	25,191	531
183	S	230 kv Rhame Substation	7,557,745	153,528	7,404,217	153,528
194	S	Bowman Sub -230 KV breakers	1,393,433	307,036	1,086,398	36,213
195	S	Hettinger Capacitors	827,735	161,156	666,579	22,789
196	S	Baker Capacitors	827,735	161,156	666,579	22,789
297	S	230 kv Neset (Tioga) Substation (T3)	9,577,219	326,753	9,250,465	270,276
310	S	345/115KV Groton Substation Addition	5,019,759	3,260,279	1,759,480	56,452
314	S	Groton 115kv Capacitor Banks	2,284,014	83,774	2,200,240	73,341
325	S	230 mw Miles City DC Tie	18,989,386	13,206,509	5,782,877	525,716
362	S	69KV Substation - Cornbelt	1,557,920	310,812	1,247,108	45,765
408	S	RC Tie East Interconnect	1,060,552	212,697	847,855	29,153
470	S	Groton Clutch	2,004,077	283,678	1,720,399	59,432
550	S	115 kV Ordway Substation	1,990,301	31,954	1,958,347	31,954
711	S	230KV LO #1 Switchyard and AVS Addition	5,087,828	4,286,434	801,395	26,713
720	S	345/230KV LO#2 Switchyard and AVS Add	16,128,277	10,758,655	5,369,623	178,987
734	S	Tioga substation - Capacitor bank	387,866	194,378	193,488	6,450
735	S	345/230KV Watertown Substation	2,871,896	2,605,285	266,611	8,887
737	S	230/115KV Logan Substation & Sask Addition	4,115,005	3,108,163	1,006,842	30,453
767	S	345KV AVS Switchyard & Charlie Creek Add't	24,808,018	13,364,301	11,443,717	380,319
		Total Substations	**139,825,733**	**74,777,322**	**65,048,411**	**2,373,439**

Basin Electric Power Cooperative
Maintenance Buildings & Microwave
December 31, 2010

cpx	Type	Description	Book Basis Amount	Accum Depr_LTD	Net Book Amount	Depr_YTD
070	TSM	Mandan Transmission Maint Bldg	7,844,363	5,124,409	2,719,954	308,451
071	TSM	Gettysburg Trans Maint Bldg	1,157,884	1,032,659	125,225	42,120
072	TSM	Groton Trans Maint Bldg	2,106,092	1,443,849	662,242	163,936
109	TSM	Logan Trans Maint Bldg	1,527,237	1,132,393	394,844	80,369
119	TSM	Broadland Trans Maint Bldg	1,127,955	1,049,720	78,235	15,393
120	TSM	AVS Plantsite Trans Maint Bldg	4,153,615	3,288,604	865,010	137,845
		Total TSM Buildings	**17,917,146**	**13,071,635**	**4,845,511**	**748,115**
043	M	Microwave - North Dakota	10,619,076	7,488,465	3,130,610	530,545
044	M	Microwave -South Dakota	4,913,744	3,935,009	978,735	274,655
136	M	Microwave - SD AVS	897,056	802,610	94,446	36,828
137	M	Microwave - AVS	2,175,315	1,329,415	845,900	112,829
139	M	Microwave - ND Sask	1,340,022	1,231,819	108,202	58,482
155	M	Microwave - ND CC	1,061,358	969,853	91,506	47,385
308	M	Microwave - SD Groton	143,259	136,084	7,175	7,723
			21,149,830	15,893,255	5,256,575	1,068,447
		Microwave adjustment	(10,371,658)	(7,793,888)	(2,577,770)	(523,955)
		Total Microwave	10,778,172	8,099,367	2,678,805	544,492
		Adjustments to accumulated depreciation		(10,786,702)		
		Total IS Transmisssion	**429,974,376**	**222,893,809**	**207,080,567**	**7,171,423**

Basin Electric Power Cooperative
MBPP Facilities
December 31, 2010

cpx	Type	Description	Book Basis Amount	Accum Depr_LTD	Net Book Amount	Depr_YTD
049	L	345Kv-048 To Ne Bord-MBPP Steg	5,917,563	3,585,556	2,332,007	93,746
050	L	345Kv-Ne Bord To 078-MBPP E St	519,922	306,275	213,646	8,064
051	L	345Kv-Archer Jct-NE Brd-MBPP E	2,392,317	1,392,772	999,546	39,734
052	L	345Kv-NE Bord-079-MBPP E Sidney	3,702,714	2,122,503	1,580,211	60,697
053	L	345Kv-078 To 079-MBPP East	4,971,800	2,846,064	2,125,736	62,920
073	L	230Kv-048-076-MBPP W (D.Johston)	2,868,108	1,721,120	1,146,988	32,461
074	L	345Kv-048-Co Bord-MBPP W(Story	18,392,775	11,353,910	7,038,865	211,553
075	L	345Kv-Co Bord-190-MBPP W(Story	16,558,245	9,929,299	6,628,947	201,234
077	L	LRS Plant Site Lines	1,255,831	703,060	552,771	18,426
091	L	Nebraska Tax Allocation	161,866	94,368	67,498	3,447
101	L	230Kv Tie-079-Exist 100-MBPP E	499,280	303,724	195,556	6,193
102	L	230Kv Tie-050 To 084-MBPP W	353,438	205,568	147,870	4,419
103	L	230Kv Tie Ln-078 To 084-MBPP E	311,212	184,061	127,151	3,830
104	L	345Kv-048 To Co Border-MBPP W	8,978,538	4,827,775	4,150,763	113,962
105	L	345Kv-Co Border-Ault,CO MBPP W	3,597,852	1,947,691	1,650,161	46,525
106	L	230Kv-084-100-MBPP W (Tri-State)	268,113	165,207	102,907	3,430
		Total Lines	**70,749,575**	**41,688,953**	**29,060,622**	**910,642**
045	S	230Kv LRS Substation-MBPP West	2,289,416	1,332,325	957,091	31,903
048	S	345Kv LRS Substation-MBPP	5,891,131	3,671,438	2,219,693	73,990
076	S	230Kv Dave Johnston Sub-MBPP W	379,358	232,217	147,141	4,776
078	S	345/230Kv Stegall NE Sub-MBPP	3,014,708	1,836,650	1,178,058	38,768
079	S	345/230Kv Sidney NE Sub-MBPP E	4,087,973	2,484,600	1,603,373	51,517
084	S	230Kv Stegl USBR Sub Addt-MBPP	599,773	359,839	239,934	7,998
085	S	345Kv Ault Co Sub-MBPP West	2,548,498	1,838,587	709,911	63,536
086	S	230Kv Story Co Sub-MBPP West	318,274	129,702	188,572	4,236
088	S	230Kv Stegall Sub-Tri-St Addt	69,131	48,320	20,811	1,861
096	S	Tools And Equip-MBPP-Tri-State	12,498	12,498	-	-
100	S	230/115Kv Sidney-Tri-State Sub	303,138	107,079	196,059	5,286
190	S	345Kv Story Co Sub-MBPP W	2,884,151	1,636,714	1,247,438	40,531
		Total Substations	**22,398,049**	**13,689,969**	**8,708,080**	**324,402**
107	TSM	MBPP Stegall Trans Maint Bldg	1,200,491	912,158	288,333	50,356
108	TSM	MBPP LRS Trans Maint Bldg	1,096,445	833,538	262,907	42,810
		Total TSM Buildings	**2,296,936**	**1,745,696**	**551,240**	**93,165**
131	MW	Microwave Comm-Wyoming-MBPP	1,325,860	889,651	436,209	72,359
132	MW	Microwave Comm-Colorado-MBPP	254,484	180,614	73,870	11,658
133	MW	Microwave Comm-Nebraska-MBPP	538,174	388,159	150,016	25,049
138	MW	Microwave Comm-South Dak-MBPP	36,572	34,483	2,089	2,184
			2,155,090	1,492,907	662,183	111,250
		Microwave Adjustment	(322,618)	(223,489)	(99,129)	(16,654)
		Total Microwave	1,832,472	1,269,418	563,054	94,596
		Adjustments to accumulated depreciation		(1,443,108)		
		Total MBPP Facilities	**97,277,032**	**56,950,928**	**40,326,105**	**1,422,805**

Basin Electric's Ancillary Services Cost Data

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2012

Summary

A	Total LOS and AVS Net Plant Investment	$	511,521,518	(ancillary worksheet 1)
B	Facilities with AGC (LOS 1 & AVS)	$	398,613,472	(Ancillary worksheet 1 less LOS 2)
C	B/A		77.9270%	
D	AGC Facilities	$	43,182	
E	AGC Facilities Percentage (D/B)		0.0108%	
F	Generation Revenue Requirement	$	210,461,593	(Generation revenue require LO#1 and AVS)
G	Plant Allocated to AGC	$	22,799	(E x F)
H	**Regulation Revenue Requirement**	**$**	**65,981**	(D + G)

Basin Electric Power Cooperative
Generation Plant
December 31, 2010

	LO #1	LO #2	AVS #065	*AVS #066	LRS #006	LRS #007	LRS #008	DFS	Other 340-347	Total
Gross Plant - Production	101,516,520	231,241,397	646,222,580	213,573,926	186,729,963	180,150,851	206,775,912	806,995	313,817,547	2,080,835,691
Accum Depr - Production	(67,614,379)	(119,752,143)	(366,021,933)	(114,220,965)	(123,058,721)	(113,679,877)	(131,265,020)	-	(52,888,223)	(1,088,501,261)
Accum Depr - Adjustment	2,458,304	1,418,791	3,142,899	2,102,086	2,239,004	1,965,753	2,025,563			15,352,400
Net Book (RUS 310-349)	36,360,445	112,908,046	283,343,546	78,909,482	65,910,246	68,436,727	77,536,455	806,995	260,929,324	1,007,686,830

*AVS unit #066 adjusted for generation into MISO.

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2010

Line No			Total	Allocator		Total Production	(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) Other
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ 370,203,497	$ 31,505,774	$ 42,923,404	$ 105,868,564	$ 73,087,156	$ 116,818,500
							44.91%				
	REVENUE CREDITS										
2	Third Party Receipts			TP	1.00000						
3											
4	Third Party Payments			TP	1.00000						
5		(line 2 + 4)									
6	NET REVENUE REQUIREMENT	(line 1 - 5)									

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2010

	(1)	(2) Worksheets	(3)	(4) Allocator A		(5) Total Production	(4a) Allocator B		(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) Other
	GROSS PLANT IN SERVICE (Note A)												
1	Production	12h A 6 e	2,090,835,693	DA	100.000%	2,060,835,693	NA	100.000%	101,516,520	231,241,397	646,222,580	213,573,926	888,281,270
2	Transmission	12h A 11 e & 12h A 23 e	660,421,046	DA	N/A	-	DA	N/A	-	-	-	-	-
3	Distribution	12h A 16 e		NA	0.000%	-	NA	0.000%	-	-	-	-	-
4	General	12h A 18 e	136,072,680			-			-	-	-	-	-
4a	Direct Assign - Transmission (Note B)		30,168,125	DA	N/A	-	DA	N/A	-	-	-	-	-
4b	Direct Assign - Production		40,766,696	NA	100.000%	40,766,696	NA	100.000%	7,010,760	7,010,760	7,374,443	7,374,443	11,995,290
4c	Other		65,137,858	WS	87.879%	57,242,652	WS	Gross Plant	2,792,664	6,361,324	17,777,230	5,875,302	24,435,132
5	Intangible	12h A 1 e	78,022,312	DA	100.000%	1,049,145	DA	100.000%	-	-	524,573	524,573	-
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h A 18 e & 12h A 24 e	$ 2,955,351,730			$ 2,179,894,187			$ 111,319,944	$ 244,613,482	$ 671,898,825	$ 227,348,243	$ 924,713,692
							GP1	Gross Plant	4.879%	11.113%	31.056%	10.264%	42.689%
	ACCUMULATED DEPRECIATION												
7	Production	12h B 1-4 f	1,073,148,861	DA	100.000%	1,073,148,861	NA	0.000%	65,156,075	118,333,351	362,679,034	112,118,878	414,661,522
8	Transmission	12h B 5 f & 12h B 15 f	271,817,338	N/A	100.000%	-	DA	100.000%	-	-	-	-	
9	Distribution	12h B 6 f		NA	0.000%	-	NA	0.000%	-	-	-	-	
10	General	12h B 7 f	95,677,218			-			-	-	-	-	
10a	Direct Assign - Transmission		19,386,585	N/A	0.000%	-	DA	0.000%	-	-	-	-	
10b	Direct Assign - Production		31,037,170	DA	100.000%	31,037,170	DA	100.000%	5,311,904	5,311,904	6,263,855	6,263,855	7,885,953
10c	Other		45,253,463	WS	87.879%	39,768,398	GP1	Gross Plant	1,940,158	4,419,425	12,350,440	4,081,770	16,976,604
11	Intangible	12h B 12 f	47,082,040	DA	100.000%	264,385	DA	100.000%	-	-	132,193	132,193	-
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h B 16 f less 12h B 14 f	$ 1,487,725,456			$ 1,144,218,813			$ 72,408,137	$ 128,064,682	$ 381,625,521	$ 122,596,696	$ 439,523,778
	NET PLANT IN SERVICE												
13	Production	(line 1 - line 7)	1,007,686,832	AUTO		1,007,686,832	AUTO		36,360,445	112,908,046	283,343,546	101,455,048	473,619,748
14	Transmission	(line 2 - line 8)	388,603,708	AUTO		-	AUTO		-	-	-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	-	-	-
16	General	(line 4 - line 10)	40,395,462	AUTO		-	AUTO		-	-	-	-	-
16a	Direct Assign	(line 4a - line 10a)	10,781,540	AUTO		-	AUTO		-	-	-	-	-
16b	Production	(line 4b - line 10b)	9,729,526	AUTO		9,729,526	AUTO		1,698,857	1,698,857	1,110,588	1,110,588	4,110,637
16c	Other	(line 4c - line 10c)	19,884,395	AUTO		17,474,255	AUTO		852,506	1,941,898	5,426,790	1,793,532	7,459,528
17	Intangible	(line 5 - line 11)	30,940,272	AUTO		784,760	AUTO		-	-	392,380	392,380	-
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,467,626,274			$ 1,035,675,374			$ 38,911,807	$ 116,548,800	$ 290,273,304	$ 104,751,548	$ 486,189,914
	WORKING CAPITAL												
19	CWC (Note C)	one eighth of line 9, page 3	32,922,692	DA	100.000%	32,072,472	DA	100.000%	3,297,806	3,750,139	9,151,968	7,643,380	8,229,170
20	Materials & Supplies Production	12h Section G L 3 C e	31,654,629	DA	100.000%	31,654,629	GP1	Gross Plant	1,544,316	3,517,750	9,830,635	3,248,985	13,512,943
21	Prepayments (Note C)	12a Section B L 35		GP1	0.000%	-	GP1	Gross Plant					
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 64,577,321			$ 63,727,101			$ 4,842,122	$ 7,267,889	$ 18,982,603	$ 10,892,365	$ 21,742,122
23	Rate Base		$ 1,532,203,595			$ 1,099,402,474			$ 43,753,929	$ 123,816,690	$ 309,255,906	$ 115,643,913	$ 506,932,036

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2010

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator A		(5) Total Production	(5a) Allocator B			(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) Other
	O&M													
1	Production Plant (Note D)	RUS 12a, L5 & L15	211,957,041	DA	100.000%	211,957,041	DA	100.000%		23,550,650	23,550,650	55,189,414	55,189,414	54,486,914
2	Direct Assignment	Accounting Records		NA	0.000%	-	NA	0.000%		-	-	-	-	
3	Other	Accounting Records		TPW	100.000%		GP1	Gross Plant						
4	A&G	RUS 12a, Section A, L 13 C b	51,414,492			-								
5	Less Regulatory Fees (Note E)	Accounting Records	160,640	NA	0.000%	-	NA	0.000%						
6	Production	Accounting Records	2,570,094	DA	100.000%	2,570,094	NA	0.000%						2,570,094
7	Transmission (Note F)	Accounting Records	842,350	DA/TPW	0.000%	-	DA/TPW	page 4		-	-	-	-	
8	Headquarters (Note G)		47,841,378	WS	87.879%	42,042,637	GP2	Gross Plant		4,831,795	6,450,460	18,026,327	5,957,628	8,776,427
9	TOTAL O&M (sum lines 1 and 4)	Expense Worksheet	$ 263,381,533			$ 256,579,772				$ 28,382,445	$ 30,001,110	$ 73,215,741	$ 61,147,042	$ 65,833,435
	DEPRECIATION & AMORTIZATION EXPENSE													
10	Depreciation and Amortization Expense	Accounting Records	55,153,939											
11	Transmission	Accounting Records	11,147,383	NA	0.000%	-	NA	0.000%						
12	Production	Accounting Records	33,389,356	DA	100.000%	33,289,356	DA	100.000%		1,416,384	3,637,449	10,295,593	3,247,645	14,692,285
13	General Plant	Accounting Records	5,470,586	NA	0.000%	-	NA	0.000%						
14	Transmission	Accounting Records	1,719,123	NA	0.000%	-	NA	0.000%						
15	Production	Accounting Records	3,246,261	DA	100.000%	3,246,261	DA	100.000%		613,313	613,313	571,700	571,700	876,236
16	Other General Plant		3,505,502	WS	87.879%	3,080,608	GP1	Gross Plant		150,292	342,345	956,711	316,189	1,315,071
17	Other Amortization		2,246,315	DA	100.000%	50,359	DA	100.000%				25,179	25,179	
18	TOTAL (Sum lines 10,13,17)	Expense Worksheet, L 20 C a	$ 65,163,939			$ 39,666,584				$ 2,179,989	$ 4,593,107	$ 11,849,183	$ 4,160,713	$ 16,883,592
	TAXES OTHER THAN INCOME TAXES													
19	PLANT RELATED													
20	Property total	2010 12a A 21 (less income tax)	2,288,218											
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%						
22	Gross Receipts (Note H)	2010 RUS Form 12	2,285,217	NA	0.000%	-	DA	100.000%		-	-	-	-	
23	Production			NA	0.000%		NA	0.000%						
24	TOTAL OTHER TAXES		$ 2,288,217			$ -				$ -	$ -	$ -	$ -	
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 320,833,689			$ 296,246,357				$ 28,562,434	$ 34,594,217	$ 85,064,924	$ 65,307,755	$ 82,717,027
26	Return		$ 103,071,804	WCC	Rate Base	$ 73,957,140	WCC	Rate Base	6.73%	$ 2,943,340	$ 8,329,187	$ 20,803,739	$ 7,779,401	$ 34,101,673
27	REV. REQUIREMENT (sum lines 25+26)		$ 423,895,493			$ 370,203,497				$ 31,505,774	$ 42,923,404	$ 105,868,663	$ 73,087,156	$ 116,818,700

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent
1	Production	Accounting Records	40,022,765	WS	% of total wages	87 879%
2	Transmission-East	Accounting Records	225,620			
3	Transmission-West	Accounting Records	406,558		GP2 % excluding MBPP West	
4	Transmission-Allocated	Accounting Records	4,887,971			
5	Distribution					
6	Other Transmission					
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$45,542,914			

	(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) Other
GP2	6 736%	15 343%	42 876%	14 170%	20 875%

Note I	Weighted Cost of Capital		Percent	Rate	Weighted cost
12a BL 46 & L 52	LTD	2,496,279,873	72 55%	5 17%	3 75%
12b BL 39	Equity	944,410,019	27.45%	10 85%	2 98%
		3,440,689,892	100 00%		6 73%

Note
A Line 1, page 2 excludes $1,922,004 and is included in line 2, page 2 Line 2 also includes $2,825,409 transmission acquisition adjustment
Accumulated Depreciation for 275 097, associated with the $1,922,004 is excluded in line 7 and added to line 8
B General Plant directly assigned to production includes the common facilities and microwave assigned to production
C Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3, line 9, column 6-8
Prepayments are the electric related prepayments booked to Account No 165 and reported on Section B, line 24, on the RUS 12 form
D Costs assigned to plant based on RUS Forms 12 D and 12 F
E Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings
F A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
G MBPP plant is excluded in the percentage calculations on page 4, GP2, as these are directly allocated to MBPP
H 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
I Equity percent as a percent of total long term debt plus current portion of long term debt plus equity

Heartland's Transmission Cost Data

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 901,167
	REVENUE CREDITS	(Note P)				
2	Account No. 454	(page 4, line 30)	24,738	TP	0.53801	$13,309
3	Account No. 456.1	(page 4, line 33)	0	TP	0.53801	0
4	Revenue From Existing Transmission Agreements		0	NA	1.00000	0
5	Transmission Service Credits		0	NA	1.00000	0
6	TOTAL REVENUE CREDITS					13,309
	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 887,857

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Schedule A	43,687,899	NA		
2	Transmission	Schedule A	15,104,251	TP	0.53801	8,126,268
3	Distribution		0	NA		
4	General & Intangible	Schedule A	6,598,559	W/S	0.06994	461,513
5	Common		0	CE	0.06994	0
6	TOTAL GROSS PLANT (sum lines 1-5)		65,390,709	GP=	13.133%	8,587,781
	ACCUMULATED DEPRECIATION					
7	Production	Schedule A	32,167,045	NA		
8	Transmission	Schedule A	11,321,887	TP	0.53801	6,091,311
9	Distribution		0	NA		
10	General & Intangible	Schedule A	2,823,742	W/S	0.06994	197,497
11	Common		0	CE	0.06994	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		46,312,674			6,288,808
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	11,520,854			
14	Transmission	(line 2- line 8)	3,782,364			2,034,957
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	3,774,817			264,016
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		19,078,035	NP=	12.050%	2,298,973
	ADJUSTMENTS TO RATE BASE (Note A)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.12050	0
21	Account No. 283 (enter negative)		0	NP	0.12050	0
22	Account No. 190		0	NP	0.12050	0
23	Account No. 255 (enter negative)		0	NP	0.12050	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE (Note B)		0	TP	0.53801	0
	WORKING CAPITAL (Note C)					
26	CWC		474,601			54,300
27	Materials & Supplies (Note B)		0	TE	1.00000	0
28	Prepayments		114,025	GP	0.13133	14,975
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		588,626			69,275
30	RATE BASE (sum lines 18, 24, 25, and 29)		19,666,661			2,368,248

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	Schedule A	242,995	TE	1.00000	242,995
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565		61,453	NA	1.00000	61,453
3	A&G (Note G)	Schedule A	3,615,268	W/S	0.06994	252,857
4	Less FERC Annual Fees		0	W/S	0.06994	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.06994	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.06994	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 2, 4, 5)		3,796,810			434,399
	DEPRECIATION EXPENSE					
9	Transmission	Schedule A	402,923	TP	0.53801	216,777
10	General	Schedule A	164,947	W/S	0.06994	11,537
11	Common		0	CE	0.06994	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		567,870			228,314
	TAXES OTHER THAN INCOME TAXES (Note F)					
	LABOR RELATED					
13	Payroll	Schedule A	91,135	W/S	0.06994	6,374
14	Highway and vehicle		0	W/S	0.06994	0
15	PLANT RELATED					
16	Property	Schedule A	174,573	GP	0.13133	22,927
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.13133	0
19	Payments in lieu of taxes		0	GP	0.13133	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		265,708			29,301
	INCOME TAXES (Note G)			NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote G.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.12050	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		1,736,866	NA		209,152
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		6,367,254			901,167

SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN IS RATES		
1	Total transmission plant (page 2, line 2, column 3)		15,104,251
2	Less transmission plant excluded from IS rates (Note H)		6,752,305
3	Less transmission plant included in OATT Ancillary Services (Note I)		225,678
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)		8,126,268
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)	TP=	0.53801
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		242,995
7	Less transmission expenses included in OATT Ancillary Services (Note J)		0
8	Included transmission expenses (line 7 less line 6)		242,995
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000
10	Percentage of transmission plant included in IS Rates (line 5)	TP	0.53801
11	Percentage of transmission expenses included in IS Rates (Note K)	TE=	1.00000

Line No.	WAGES & SALARY ALLOCATOR (W&S)	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	1,102,057	0.00	0			
13	Transmission	164,675	0.54	88,597			
14	Distribution	0	0.00	0			
15	Other	0	0.00	0			
16	Total (sum lines 12-15)	1,266,732		88,597	=	0.06994	= W/S

Line No.	COMMON PLANT ALLOCATOR (CE) (Note L)	$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
17	Electric	65,390,709	1.00000	*	0.06994	=	0.06994
18	Gas	0					
19	Water	0					
20	Total (sum lines 17-19)	65,390,709					

Line No.	RETURN (R)		$			
21	Long Term Interest	Schedule A	$1,614,451			
			$	**%**	**Cost (Note M)**	**Weighted**
22	Long Term Debt	Schedule A	26,199,546	57%	6.16%	0.0352 =WCLTD
23	Proprietary Capital	Schedule A	19,708,994	43%	12.38%	0.0531
24	Total (sum lines 22, 23)		45,908,540	100%		0.0883 =R
25					Proprietary Capital Cost Rate =	12.38%
26					TIER =	1.43

Line No.	REVENUE CREDITS		Load
	ACCOUNT 447 (SALES FOR RESALE)		
27	a. Bundled Non-RQ Sales for Resale	(Note N)	0
28	b. Bundled Sales for Resale included in Divisor on page 1		0
29	Total of (a)-(b)		0
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$24,738
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
31	a. Transmission charges for all transmission transactions		$0
32	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
33	Total of (a)-(b)		$0

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

General Note: References to pages in this revenue requirement template are indicated as: (page#, line#, col.#)

Note Letter	
A	Does not apply to Heartland. For others, 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.
B	Transmission related only.
C	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 as shown on Schedule I of EIA Form 412.
D	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
E	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.
F	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.
G	Heartland is not subject to Federal or State Income Tax

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

H	Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect applicaton of seven-factor test).
I	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.
J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
K	All O&M expense included in Page 3 line 1 column 3 is associated with transmission plant in IS rates. The O&M expense for non-qualifying facilities (Page 4 lines 2,3) is the responsibility of others.
L	Heartland has no common plant.
M	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
N	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 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	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 IS (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 Customer Facility Credits

Missouri River Energy Services
Facility Credits

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 8,949,170	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 30)	135,812	TP	1.00000	135,812	
3	Account No. 456.1	(page 4, line 33)	57,906	TP	1.00000	57,906	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0	Line 5 supported by schedules
6	TOTAL REVENUE CREDITS (sum lines 2-5)					193,718	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 8,755,452	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	732,481	
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 S)					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)					732,481	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	11.953				
17	Network & P-to-P Rate ($/kW/Mo)	(line 11 / 12)	0.996				

Line No.			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.230		$0.230	
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.046	Capped at weekly rate	$0.033	
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 times 1,000)	2.873	Capped at weekly and daily rates	$1.365	
21	FERC Annual Charge ($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

Line No	(1) RATE BASE:		(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE						
1	Production	IV.6.c		293,509,353	NA		
2	Transmission	IV 7.c		70,289,426	TP	1 00000	70,289,426
3	Distribution	IV 8.c		0	NA		
4	General & Intangible	IV 9.c		13,511,488	W/S	0 15258	2,061,545
5	Common			0	CE	0.15258	0
6	TOTAL GROSS PLANT (sum lines 1-5)			377,310,267	GP=	19 175%	72,350,971
	ACCUMULATED DEPRECIATION						
7	Production			174,226,037	NA		
8	Transmission			33,266,237	TP	1.00000	33,266,237
9	Distribution			0	NA		
10	General & Intangible			6,534,073	W/S	0 15258	996,951
11	Common			0	CE	0.15258	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)			214,026,347			34,263,188
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)		119,283,316			
14	Transmission	(line 2- line 8)		37,023,189			37,023,189
15	Distribution	(line 3 - line 9)		0			
16	General & Intangible	(line 4 - line 10)		6,977,415			1,064,595
17	Common	(line 5 - line 11)		0			0
18	TOTAL NET PLANT (sum lines 13-17)			163,283,920	NP=	23.326%	38,087,784
	ADJUSTMENTS TO RATE BASE (Note F)						
19	Account No. 281 (enter negative)			0		zero	0
20	Account No. 282 (enter negative)			0	NP	0.23326	0
21	Account No. 283 (enter negative)			0	NP	0.23326	0
22	Account No. 190			0	NP	0.23326	0
23	Account No. 255 (enter negative)			0	NP	0.23326	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)			0			0
25	LAND HELD FOR FUTURE USE	IV.12.c (Note G)		0	TP	1.00000	0
	WORKING CAPITAL	(Note H)					
26	CWC			1,410,892			621,849
27	Materials & Supplies	(Note G)		286,117	TE	0.98554	281,981
28	Prepayments	II.20.b		2,036,699	GP	0.19175	390,546
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)			3,733,708			1,294,376
30	RATE BASE (sum lines 18, 24, 25, and 29)			167,017,628			39,382,160

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.8.d	21,306,260	TE	0.98554	20,998,269
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0		1.00000	0
2	Less Account 565		17,690,335	TE	0.98554	17,434,614
3	A&G	VII.13.d	7,838,939	W/S	0.15258	1,196,043
4	Less FERC Annual Fees		0	W/S	0.15258	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		456,672	W/S	0.15258	69,678
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		288,946	TE	0.98554	284,769
6	Common		0	CE	0.15258	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		11,287,138			4,974,790
	DEPRECIATION EXPENSE					
9	Transmission		738,839	TP	1.00000	738,839
10	General		559,000	W/S	0.15258	85,291
11	Common		0	CE	0.15258	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		1,297,839			824,130
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll		0	W/S	0.15258	0
14	Highway and vehicle		0	W/S	0.15258	0
15	PLANT RELATED					
16	Property		1,326,554	GP	0.19175	254,373
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.19175	0
19	Payments in lieu of taxes		0	GP	0.19175	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		1,326,554			254,373
	INCOME TAXES	(Note K)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	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)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.23326	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		12,281,260	NA		2,895,877
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		26,192,791			8,949,170
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W) [Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment GG]		0			0
31	REVENUE REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		26,192,791			8,949,170

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)						70,289,426	
2	Less transmission plant excluded from ISO rates (Note M)						0	
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)						70,289,426	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						21,306,260	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						307,991	
8	Included transmission expenses (line 6 less line 7)						20,998,269	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.98554	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.98554	

Line No.	WAGES & SALARY ALLOCATOR (W&S)	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	2,549,769	0.00	0			
13	Transmission	476,908	1.00	476,908			
14	Distribution	0	0.00	0			
15	Other	99,003	0.00	0			
16	Total (sum lines 12-15)	3,125,680		476,908	=	0.15258	= W/S

Line No.	COMMON PLANT ALLOCATOR (CE) (Note O)	$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
17	Electric	377,310,267					
18	Gas	0	1.00000	*	0.15258	=	0.15258
19	Water	0					
20	Total (sum lines 17-19)	377,310,267					

Line No.	RETURN (R)		$				
21	Long Term Interest	III.16.b + III.17.b (Note U)	$15,828,160				
			$	%	Cost (Note P)	Weighted	
22	Long Term Debt	II.33.b + II.34.b	277,500,000	75%	5.70%	0.0429	=WCLTD
23	Proprietary Capital	II.32.b	91,056,628	25%	12.38%	0.0306	
24	Total (sum lines 22, 23)		368,556,628	100%		0.0735	=R
25					Proprietary Capital Cost Rate =	12.38%	
26					TIER =	1.29	

Line No.				
	REVENUE CREDITS		Load	
	ACCOUNT 447 (SALES FOR RESALE)			
27	a. Bundled Non-RQ Sales for Resale	(Note Q)	0	
28	b. Bundled Sales for Resale included in Divisor on page 1		0	
29	Total of (a)-(b)		0	
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$135,812	
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)			
31	a. Transmission charges for all transmission transactions		$16,367,480	Line 31 supported by notes in Form 412 or detailed Schedule
32	b. Transmission charges for all transmission transactions included in Divisor on page 1		$16,309,574	Line 32 supported by notes in Form 412 or detailed Schedule
32a	c. Transmission charges associated with Schedule 26 (Note X)		$0	
33	Total of (a)-(b)-(c)		$57,906	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data
Missouri River Energy Services

For the 12 months ended 12/31/12 (Estimated)

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 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone 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 applicable pricing zone coincident monthly peaks.
C	LF as defined above at time of applicable pricing zone coincident monthly peaks.
D	LF as defined above at time of applicable pricing zone coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
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
G	Transmission related only
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 as shown on Schedule I of EIA Form 412.
I	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.
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. multiplied by (1/1-T) (page 3, line 26).

Inputs	FIT =	0.00%	
	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 Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 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 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 22) The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
Q	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 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.
U	From Reference II.17.b include only the amount from Account 430.
V	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG and recovered under Schedule 26 of the Midwest ISO Tariff
X	Removes from revenue credits revenues that are distributed pursuant to Schedule 26 of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Based on Gross Plant

Control Area	ATRR	Divisor
OTP	$ 4,852,703	112,893
WAPA *	$ 3,902,748	
ATRR in Zones	$ 8,755,452	

* = Not in MISO.

	ATRR	Gross Plant
WAPA Facilities:	$ 3,658,881	$ 29,373,772
Irv Simmons	$ 243,867	$ 1,957,786
MBPP	$ 3,902,748	$ 31,331,558

Pricing Zone	Gross Plant	Allocation
OTP	$38,957,868	55.42%
WAPA *	$31,331,558	44.58%
Total Transmission Plant	$70,289,426	100.00%

* = Not in MISO.

Please fill out info requested in the box below

Schedule 1 Recoverable Expenses	
$307,991	Acct 561.1 - 561.3, 561.BA included in Line 7
$0	Acct 561.BA for Schedule 24
$307,991	Acct 561.1 - 561.3 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
$0	transactions <1 yr
$0	non-firm
$0	transactions w/ load not in divisor
$0	total Revenue Credits
$307,991	Net Schedule 1 Expenses (Acct 561.1-561.3 minus Credits)

NWPS
Facility Credits

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)				$ 3,473,780
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	169,771	TP	0.83220	141,283
3	Account No. 456	(page 4, line 37)	72,942	TP	0.83220	60,702
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.83220	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.83220	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					201,985
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 3,271,795
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	243,862
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	14,000
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					257,862
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	12.688			
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.057			

Line No.			Peak Rate	Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.244	$0.244
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.049 Capped at weekly rate	$0.035
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.050 Capped at weekly and daily rates	$1.452
21	FERC Annual Charge($/MWh)	(Note E)	$0.000 Short Term	$0.000 Short Term
22			$0.000 Long Term	$0.000 Long Term

Formula Rate - Non-Levelized	NWPS Rate Formula Template Utilizing FERC Form 1 Data	For the 12 months ended 12/31/10

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	160,809,843	NA			
2	Transmission	206.53.g	37,068,925	TP	0.83220	30,848,681	6,220,244
3	Distribution	206.69.g	231,358,884	NA			
4	General & Intangible	206.5.g & 83.g	10,588,800	W/S	0.08071	854,614	
5	Common	356.1	21,084,142	CE	0.05060	1,066,893	
6	TOTAL GROSS PLANT (sum lines 1-5)		460,910,594	GP=	7.110%	32,770,188	
	ACCUMULATED DEPRECIATION						Accumulated Depreciation of Joint Plant Transmission Facilities, see Assets file
7	Production	219.18-22.c	106,195,863	NA			
8	Transmission	219.23.c	23,416,063	VEst.	75.176%	17,603,154	-5,812,909
9	Distribution	219.24.c	89,702,256	NA			
10	General & Intangible	219.25.c	2,431,212	W/S	0.08071	196,221	
11	Common	356.1	5,257,460	CE	0.05060	266,036	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		227,002,853			18,065,412	
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)	54,613,980				
14	Transmission	(line 2- line 8)	13,652,862			13,245,527	
15	Distribution	(line 3 - line 9)	141,656,628				
16	General & Intangible	(line 4 - line 10)	8,157,588			658,392	
17	Common	(line 5 - line 11)	15,826,683			800,857	
18	TOTAL NET PLANT (sum lines 13-17)		233,907,741	NP=	6.287%	14,704,776	
	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	-46,240,385	NP	0.06287	-2,906,935	
21	Account No. 283 (enter negative)	277.9.k	-2,197,034	NP	0.06287	-138,118	
22	Account No. 190	234.8.c	9,119,761	NP	0.06287	573,320	
23	Account No. 255 (enter negative)	267.8.h	-1,793,779	NP	0.06287	-112,767	
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-41,111,437			-2,584,600	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.75176	0	
	WORKING CAPITAL (Note H)						
26	CWC	calculated	820,434			110,946	
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	0.07110	0	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		820,434			110,946	
30	RATE BASE (sum lines 18, 24, 25, & 29)		193,616,738			12,231,223	

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	6,633,001	TE	0.83220	6,613,752	Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	5,922,347		1.00000	5,922,347	
3	A&G	323.168.b	5,852,820	W/S	0.05060	296,163	
4	Less FERC Annual Fees		0	W/S	0.05060	0	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.05060	0	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.83220	0	
6	Common	356.1	0	CE	0.05060	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)		6,563,474			887,568	
	DEPRECIATION EXPENSE						Excluded
9	Transmission	336.7.b	1,212,154	VRB00	0.75176	1,011,240	200,914
10	General	336.9.b	669,608	W/S	0.05060	33,883	
11	Common	336.10.b	1,345,290	CE	0.05060	68,074	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		3,227,051			1,113,197	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	262.i	763,562	W/S	0.05060	38,638	
14	Highway and vehicle	262.i	54,207	W/S	0.05060	2,743	
15	PLANT RELATED						
16	Property	262.i	3,149,405	GP	0.07110	223,919	
17	Gross Receipts	262.i	146,268	NA	zero	0	
18	Other	262.i	243,562	GP	0.07110	17,317	
19	Payments in lieu of taxes		0	GP	0.07110	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		4,357,003			282,616	
	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)) =		34.17%				
	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)		-1,996,006				
25	Income Tax Calculation = line 22 * line 28		5,577,651	NA		352,353	
26	ITC adjustment (line 23 * line 24)		-3,070,778	NP	0.06287	-193,047	
27	Total Income Taxes	(line 25 plus line 26)	2,506,874			159,307	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		16,321,891	NA		1,031,092	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		32,976,294			3,473,780	

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 VRB00t
1	Total transmission plant (page 2, line 2, column 3)		37,068,925	
2	Less transmission plant excluded from ISO rates (Note M)		6,220,244	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)		30,848,681	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.83220	

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		6,633,001
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 6 less line 7)		6,633,001
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	0.83220
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.83220

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.16.b	1,662,518	0.00	0				
13	Transmission	354.19.b	3,069,905	0.83	2,554,768				
14	Distribution	354.20.b	25,995,224	0.00	0				
15	Other	354.21,22,23.b	7,308,971	0.00	0				
16	Total (sum lines 12-15)		38,036,618		2,554,768	=	0.06717	= WS	
							0.08071	= Wsact	Wages & salaries by others for excluded facilities MEC, OTP, MDU

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	439,875,046	0.75338	*	0.06717	=	0.05060
18	Gas	200.3.d	143,991,901					
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		583,866,947					

RETURN (R)

Line No.			$
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

Line No.		$	%		Cost (Note P)		Weighted	
27	Long Term Debt (112, sum of 18d through 19d)	905,205,000	0.5246	0.0000	0.0587	0.0000	0.0308	=WCLTD
28	Preferred Stock (112.3d)	0	0.0000	0.0000	0.0000	0.0000	0.0000	
29	Common Stock (line 26)	820,347,000	0.4754	0.0000	0.1125	0.0000	0.0535	
30	Total (sum lines 27-29)	1,725,552,000		0.0000	0.0000	0.0000	0.0843	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			220,080
32	b. Bundled Sales for Resale included in Divisor on page 1			220,080
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$169,771
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$233,946
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$161,004
37	Total of (a)-(b)			$72,942

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