Integrated System Transmission and Ancillary Services Rate Calculation

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

Effective January 1, 2011

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective January 1, 2011

IS Transmission and Ancillary Service Rates ..... 1 - 7

IS Load Data ..... 8 -10

Western's Transmission Cost Data ..... 11 - 15

Western's Ancillary Service Cost Data ..... 16 - 40

Basin Electric's Transmission Cost Data ..... 41 - 48

Basin Electric's Ancillary Service Cost Data ..... 49 - 51

Heartland's Transmission Cost Data ..... 52 - 56

Transmission Customer Facility Credits ..... 57 - 65

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective Janaury 1, 2011

Line No.			
1			
2			
3	**Annual IS Transmission Costs**		Notes
4	Basin Electric	$46,388,310	Basin Electric Revenue Requirement Template
5	Western	$101,723,683	Western Revenue Requirement Template
6	Heartland	$1,010,268	Heartland Revenue Requirement Template
7		$149,122,261	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$6,394,624	MRES Revenue Requirement Template
12		$2,349,478	NWPS Revenue Requirement Template
13		$8,744,102	
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$157,866,363	L7 + L13

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2011

Line No.			
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$157,866,363	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	**IS Transmission System Total Load**		
9			
10		4,646,000 KW	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15		**$2.83 / KW-Mo**	L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2011

Line No.			
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$2.83 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**3.88 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2011

A.	Fixed Charge Rate	21.867%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,124,034	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,525,843	(A x B)
D.	2009 Number of Daily Tags	81,780	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$43.11**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2011 Rate.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (40.473%) and communication facilities plant (68.33%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2009 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 2011 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,750,130	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,750,130	(A+B)
D.	2009 IS Transmission System Total Load (kW-Yr)	4,593,000	(3)
E.	Annual Reactive Charge ($/kW-Yr)	$0.60	(C/D)
F.	Monthly Reactive Charge ($/kW-Mo)	$0.05	(E/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2011, 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.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2011

A.	Western Regulation Revenue Requirement	$1,258,814	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$84,204	(2)
C.	Total Regulation Revenue Requirement	$1,343,018	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,699,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.50	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.04	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2011, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2009 Watertown Control Area.

Rate for Reserves for 2011

A.	Fixed Charge Rate		15.541%	(1)
B.	Generation Net Plant Costs		$ 509,970,151	(2)
C.	Annual Cost of Generation		$ 79,254,461	(A x B)
D.	Plant Capacity (kW)		2,473,000	
E.	Cost/kW ($/kW-Yr)		$ 32.05	(C / D)
F.	Monthly Charge ($/kW-mo)		$ 2.67	(E / 12 months)
G.	Western's Load (kW-Yr)		1,587,000	(3)
H.	Capacity used for Reserves (kW)		118,000	(4)
I.	Annual Reserves Revenue Requirement	$	3,781,900	(E x H)
J.	Annual Charge ($/kW-Yr)	$	2.38	(I /G)
K.	Monthly Charge ($/kW-mo)	$	0.20	(J/12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2011 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 2009.

(4) Southwest Power Pool Reserve Sharing System.

Integrated System Load Data

2011 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

4,646

2009 IS Transmission System Total Load
Ancillary Services
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Added Network Load - Cornbelt/NIMEC	(5) Long-Term Firm Point-to-Point	Total
1	01/15/09	800	4,314		489	4803
2	02/03/09	800	4,088		499	4587
3	03/12/09	800	4,081		495	4576
4	04/07/09	800	3,435		501	3936
5	05/29/09	1700	3,151		498	3649
6	06/25/09	1700	3,910		492	4402
7	07/27/09	1500	4,082		486	4568
8	08/13/09	1800	4,263		497	4760
9	09/17/09	1700	3,426	209	500	4135
10	10/28/09	2000	3,239	272	492	4003
11	11/30/09	1900	3,679	277	501	4457
12	12/15/09	800	4,337	293	501	5131
13						
14	12 CP		3,834	263	496	4,593

2009 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 15, 2009	8:00	3005 MW	82 MW	3087 MW
February 3, 2009	8:00	2767 MW	72 MW	2839 MW
March 12, 2009	8:00	2784 MW	91 MW	2875 MW
April 7, 2009	8;00	2251 MW	65 MW	2316 MW
May 29, 2009	17:00	1868 MW	83 MW	1951 MW
June 25, 2009	17:00	2413 MW	95 MW	2508 MW
July 27, 2009	15:00	2311 MW	94 MW	2405 MW
August 13, 2009	18:00	2534 MW	86 MW	2620 MW
September 17, 2009	17:00	2532 MW	95 MW	2627 MW
October 28, 2009	20:00	2616 MW	79 MW	2695 MW
November 30, 2009	19:00	2897 MW	79 MW	2976 MW
December 15, 2009	8:00	3391 MW	96 MW	3487 MW
Total		**31,369**	**1017**	**32,386**
			Average Control Area Load	**2,699**

(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

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 119,276,574
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
3	Non-Firm Point-to-Point Transmission Service Credit		14,714,615	NA	1.00000	14,714,615
4	Revenue from Existing Transmission Agreements		2,654,630	NA	1.00000	2,654,630
5	Scheduling, System Control, and Dispatch Service Credit		104,564	NA	1.00000	104,564
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					17,552,891
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ 101,723,683

Revenue Requirement - Non-Levelized | Revenue Requirement Template Utilizing Financial Statement Results of Operations | Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

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	18,907,591	NA		
2	Transmission	Schedule 1A Total	1,029,534,571	TP	1.00000	1,029,534,571
3	Distribution	Schedule 1A Total	31,115,560	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)		1,079,557,722	GP=	95.366%	1,029,534,571
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	9,200,671	NA		
8	Transmission	Schedule 4	500,465,475	TP	1.00000	500,465,475
9	Distribution	Schedule 4	15,141,223	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)		524,807,369			500,465,475
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	9,706,920			
14	Transmission	(line 2- line 8)	529,069,096			529,069,096
15	Distribution	(line 3 - line 9)	15,974,337			
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)		554,750,353	NP=	95.371%	529,069,096
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.95371	0
21	Account No. 283 (enter negative)		0	NP	0.95371	0
22	Account No. 190		0	NP	0.95371	0
23	Account No. 255 (enter negative)		0	NP	0.95371	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	14,384,418			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	0.95366	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		14,384,418			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		569,134,771			529,069,096

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

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		51,039,778	PTP/UGP	0.95339	48,660,814
1b	Western RMR		36,317,427	PTP/RMR	0.00991	359,906
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		18,082,350	PTP/UGP	0.95339	17,239,532
3b	Western RMR		9,635,791	PTP/RMR	0.00991	95,491
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)		115,075,346			66,355,743
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		26,830,121	PTP/UGP	0.95339	25,579,569
9b	Western RMR		14,844,626	PTP/RMR	0.00991	147,110
10	General		0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		41,674,747			25,726,679
	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	0.95366	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.95366	0
19	Payments in lieu of taxes		0	GP	0.95366	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)) = where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote I.		0.00%			
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	0.95371	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)]		29,253,527	NA		27,194,152
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		186,003,620			119,276,574

Revenue Requirement - Non-Levelized | Revenue Requirement Template Utilizing Financial Statement Results of Operations | Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

SUPPORTING CALCULATIONS AND NOTES

Line No.						
	TRANSMISSION PLANT INCLUDED IN IS RATES					
1	Total transmission plant (page 2, line 2, column 3)					1,029,534,571
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)					1,029,534,571
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	19,388,138	1.00	19,388,138		
14	Distribution	0	0.00	0		W&S Allocator
15	Other		0.00	0		($ / Allocation)
16	Total (sum lines 12-15)	19,388,138		19,388,138	=	1.00000
	PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)	$				
17	Transmission Plant in Service UGP	1,023,181,684				
18	Total Plant in Service UGP	1,073,204,835				
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)			PTP/UGP	=	0.95339
20	Transmission Plant in Service RMR	6,352,887				
21	Total Plant in Service RMR	640,798,643				
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)			PTP/RMR	=	0.00991
	COMMON PLANT ALLOCATOR (CE) (Note N)	$		% Electric	Labor Ratio	
23	Electric	0		(line 17 / line 20)	(line 16)	CE
24	Gas	0		0.00000	* 1.00000	= 0.00000
25	Water	0				
26	Total (sum lines 17-19)	0				
	RETURN (R)	$				
27	Long Term Interest Schedule 5	$34,313,681				
		$	%	Cost (Note O)	Weighted	
		HFD Sch's 21RX & 21X Col 8 Lines				
28	Long Term Debt	23,25,26,29,30 667,509,943	100%	0.0514	0.0514	=WCLTD
29	Proprietary Capital		0%	0.1238	0.0000	
30	Total (sum lines 22-23)	667,509,943	100%		0.0514	=R
31				Proprietary Capital Cost Rate =	12.38%	
32				TIER =	1.00	
	REVENUE CREDITS				Load	
	ACCOUNT 447 (SALES FOR RESALE)					
33	a. Bundled Non-RQ Sales for Resale	(Note P)			0	
34	b. Bundled Sales for Resale included in Divisor on page 1				0	
35	Total of (a)-(b)				0	
36	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)				79,082	
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)					
37	a. Transmission charges for all transmission transactions					
38	b. Transmission charges for all transmission transactions included in Divisor on page 1					
39	Total of (a)-(b)				$0	

Revenue Requirement - Non-Levelized | Revenue Requirement Template Utilizing Financial Statement Results of Operations | Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

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 2011 (WESTERN'S COSTS)

A. Fixed Charge Rate	15.541%	(1)
B. Generation Net Plant Costs ($)	$509,970,151	(2)
C. Annual Cost of Generation ($)	$79,254,461	(A x B)
D. Capability Used for Reactive Support (%)	3.47%	(3)
E. Reactive Service Revenue Requirement	$2,750,130	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2011 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 2005-2009.

REGULATION AND FREQUENCY RESPONSE FOR 2011
(Western's Costs)

A.	Fixed Charge Rate	12.594%	(1)
B.	Corps Generation Net Plant Costs ($)	173,487,614	(2)
C.	Annual Corps Generation Cost ($)	21,849,030	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	23.32	(C / D)
F.	Capacity Used for Regulation (kW)	53,980	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$1,258,814	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$1,258,814	
J.	Load in Control Area(s) (kW-Yr)	2,699,000	(4)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2011 Rate.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/09.

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

(4) Average of monthly peaks for 2009 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
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	8.902%	L8
47			
48	A&G Expense	0.042%	L17
49			
50	Depreciation Expense	2.754%	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	3.843%	L41
57			
58	Total	15.541%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	15.541%	L59
64			
65	Net Generation Plant Investment	$644,373,587	L6
66			
67	Western Annual Generation Revenue Requirement	$100,142,099	L63 * L65
68			

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	$17,746,903	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$644,373,587	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.754%	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	3.843%	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
1			
2	**A. Operation and Maintenance Expense for Generation**		
3			
4	Generation O&M Expense	$57,363,003	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$644,373,587	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	8.902%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$270,400	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$644,373,587	L6
16			
17	A&G as % of Net Generation Plant Investment	0.042%	L13/L15
18			
19			

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	$23,797,237	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$427,039,348	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	5.573%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L17
14			
15	Net Corps Generation Plant Investment	$427,039,348	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	$13,571,913	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$427,039,348	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	3.178%	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	3.843%	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	5.573%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	3.178%	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	3.843%	L41
57			
58	Total	12.594%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	12.594%	L69
64			
65	Net Corps Generation Plant Investment	$427,039,348	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$53,781,335	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	$45,937,864	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$45,937,864	L4 + L5
7			
8	Net Transmission Plant Investment	$505,697,544	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.084%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$14,717,153	A&G Expenses Worksheet, C6L12
16			
17	Net Transmission Plant Investment	$505,697,544	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.910%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$22,139,465	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$505,697,544	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.378%	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	5.495%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.084%	L10
49			
50	A&G Expense	2.910%	L19
51			
52	Depreciation Expense	4.378%	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	5.495%	L43
59			
60	Total	21.867%	

O&M Expenses - Ancillary Services
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	282,225,951	99,665,355			381,891,306
3						
4	Less:					
5	Other Power Supply Expenses	219,858,889	54,925,483			274,784,372
6	A&G Expenses	15,347,921	8,546,884			23,894,805
7	Sunflower Payment		0			0
8	Prior Year Adjustments	0	0			0
9						
10	Plus:					
11	Moveable Property Interest	660,076	264,245			924,321
12	Warehouse Stores Interest	125,115	82,168			207,283
13						
14	COE/BOR Total			23,797,237	32,723,549	56,520,786
15	PS Total O&M	47,804,332	36,539,401	23,797,237	32,723,549	140,864,519
16						
17	PS-ED Transmission O&M 5/	45,576,124	361,740	0	0	45,937,864
18						
19	PS-ED Generation O&M 6/	842,217	0	23,797,237	32,723,549	57,363,003

1/ All Western UGPR O&M Expenses are from the FY 2009 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 2009 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 2009 Corps of Engineers Financial Statements

4/ Total BOR O&M Expenses are from the FY 2009 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 - Ancillary Services
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	2,141,248	1,572,009	0	0	3,713,257
3	1412	1,715,250	2,413,725	0	0	4,128,975
4	1415	7,280	4,303	0	0	11,583
5	1416	26,795	37,847	0	0	64,642
6	1421	1,018,275	737,395			1,755,670
7	1422	1,830,597	4,958			1,835,555
8	1425	5,903	3,711			9,614
9	1426	21,456	(97)			21,359
10	1431	0	0	0	0	0
11	1432	0	0	0	0	0
12	1441	4,755,224	2,774,113	0	0	7,529,337
13	1442	3,825,893	998,920	0	0	4,824,813
14	PS Total A&G	15,347,921	8,546,884	0	0	23,894,805
15						
16	PS-ED Transmission A&G 4/	14,632,539	84,614	0	0	14,717,153
17						
18	PS-ED Generation A&G 5/	270,400	0	0	0	270,400

1/ Western UGPR A&G Expenses are from the FY 2009 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 2009 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 - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR	(3) WESTERN RMR	(4) COE	(5) BOR	(6) Total
1						
2	PS Depreciation Expense	23,067,712 1/	14,844,626 2/	13,571,913 3/	3,768,583 4/	55,252,834
3						
4	PS-ED Transmission Depreciation 5/	21,992,503	146,962	0	0	22,139,465
5						
6	PS-ED Generation Depreciation 6/	406,407	0	13,571,913	3,768,583	17,746,903

1/ FY 2009 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2009 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet. All COE facilities moved to generation, therefore, there is no COE transmission depreciation.

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

COST OF CAPITAL - Ancillary Services
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 2009 Balances	629,769,146	1/	370,641,141	1/	527,623,995	1/	97,704,004	1/	1,625,738,286	
4											
5	**Interest Expenses:**										
6	FY 2009 Simple Interest	34,548,141	2/	25,139,992	2/	18,167,179	2/	4,565,736	2/	82,421,048	
7	Average Interest Rate	5.486%	L6/L3	6.783%	L6/L3	3.443%	L6/L3	4.673%	L6/L3		
8	Transmission Plant Factor	0.9934	3/	0.0066	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.495%	7/
10	Generation Plant Factor	0.0128	8/	0.0000	9/	0.6834	10/	0.3038	11/		
11	Weighted Gen. Composite Rate									3.843%	12/

1/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
3/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
4/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
5/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
6/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
7/ (C2L7*C2L8)+(C3L7*C3L8)+(C4L7*C4L8)+(C5L7*C5L8).
8/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
9/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
10/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
11/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
12/ (C2L7*C2L10)+(C3L7*C3L10)+(C4L7*C4L10)+(C5L7*C5L10).

NET PLANT INVESTMENT - Ancillary Services
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	1,007,955,730	1/	640,798,643	2/	951,706,242	3/	423,102,811	12/	3,023,563,426
3	PS-ED Transmission Plant-in-Service	960,973,825	4/	6,352,887	5/	0	6/	0		967,326,712
4	PS-ED Generation Plant-in-Service	17,758,071	7/	0		951,706,242	L2-L3	423,102,811	L2-L3	1,392,567,124
5	Generation Plant to Total Plant	0.017618	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.953389	L3/L2	0.0099	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	481,499,959	8/	259,838,836	9/	524,666,894	10/	215,043,577	11/	1,481,049,266
9	PS-ED Trans. Accumulated Depreciation	459,056,764	L6*L8	2,572,404	L6*L8	0	13/	0	L6*L8	461,629,168
10	PS-ED Gen. Accumulated Depreciation	8,483,066	L5*L8	0	L5*L8	524,666,894	L8-L9	215,043,577	L5*L8	748,193,537
11	PS-ED Net Transmission Plant	501,917,061	L3-L9	3,780,483	L3-L9	0	L3-L9	0	L3-L9	505,697,544
12	PS-ED Net Generation Plant	9,275,005	L4-L10	0	L4-L10	427,039,348	L4-L10	208,059,234	L4-L10	644,373,587

1/ Transmission Plant-in-Service Worksheet, C2L516
2/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2009 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L516.
5/ Transmission Plant-in-Service Worksheet, C5L525.
6/ Transmission Plant-in-Service Worksheet, C5L529.
7/ Transmission Plant-in-Service Worksheet, C4L516.
8/ FY 2009 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2009 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ Formerly used to account for transmission related accumulated depreciation on the COE switchyards. All COE facilities moved to generation so no transmission depreciation.

Line No.	(1) DESCRIPTION	a	(2) FY2009 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		5,099,232						5,099,232		
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		1,273,088						1,273,088		
14	CHARLIE CREEK-BELFIELD		14,655,950						14,655,950		
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		11,497,529						11,497,529		
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		7,663,747						7,663,747		
39	FORT RANDALL-FORT THOMPSON 1&2		6,717,269						6,717,269		
40	FORT RANDALL-GAVIN'S POINT		1,151,719						1,151,719		
41	FORT RANDALL-GREGORY		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		8,532,125						8,532,125		
45	FORT THOMPSON-GRAND ISLAND		16,397,505						16,397,505		
46	FORT THOMPSON-HURON 230-KV 1&2		5,033,030						5,033,030		
47	FORT THOMPSON-SIOUX FALLS 1&2		9,542,122						9,542,122		
48	GARRISON-BISMARCK 230KV 1&2		5,176,778						5,176,778		
49	GARRISON-JAMESTOWN		4,306,775						4,306,775		
50	GARRISON-MALLARD		1,266,645						1,266,645		
51	GARRISON-WM. J. NEAL		1,540,944						1,540,944		
52	GAVINS POINT-BELDEN		455,727						455,727		
53	GAVINS POINT-SIOUX FALLS		1,813,500						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		12,811,702						12,811,702		
57	GREGORY-MISSION		2,010,227						2,010,227		
58	GROTON-HURON		1,212,199						1,212,199		
59	GROTON-SUMMIT		3,176,751						3,176,751		
60	HAVRE-RAINBOW		6,720,551						6,720,551		

Line No.	(1) DESCRIPTION	a	(2) FY2009 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		1,815,333						1,815,333		
73	MALLARD-RUGBY		1,282,436						1,282,436		
74	MARTIN-MISSION		1,816,904						1,816,904		
75	MARTIN-PHILIP		1,790,108						1,790,108		
76	MAURINE-RAPID CITY		4,592,789						4,592,789		
77	MILES CITY-BAKER		8,470,654						8,470,654		
78	MILES CITY-CUSTER		3,750,704						3,750,704		
79	NEW UNDERWOOD-PHILIP		2,116,605						2,116,605		
80	NEW UNDERWOOD-RAPID CITY NO. 1		1,067,598						1,067,598		
81	NEW UNDERWOOD-RAPID CITY NO. 2		309,991						309,991		
82	NEW UNDERWOOD-STEGALL (HURON)		2,672,947						2,672,947		
83	OAHE-FORT THOMPSON 230KV 1&2		3,149,034						3,149,034		
84	OAHE-FORT THOMPSON 230KV 3&4		5,119,119						5,119,119		
85	OAHE-GLENHAM		5,768,280						5,768,280		
86	OAHE-MAURINE		1,791,779						1,791,779		
87	OAHE-NEW UNDERWOOD		6,447,607						6,447,607		
88	OAHE-PIERRE		388,816						388,816		
89	O'FALLON CREEK-MILES CITY		2,511,409						2,511,409		
90	PIERRE-PHILIP		1,187,034						1,187,034		
91	RAPID CITY-ELK CREEK 115-kV T/L		52,064						52,064		
92	RUGBY-LEEDS		2,263,096						2,263,096		
93	SHELBY-SHELBY#2		576,090						576,090		
94	SIOUX CITY-DENISON		1,661,311						1,661,311		
95	SIOUX CITY-SPENCER		1,938,353						1,938,353		
96	SIOUX FALLS- SIOUX CITY		3,217,192						3,217,192		
97	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE		277,897						277,897		
98	SUMMIT-WATERTOWN		6,743,203						6,743,203		
99	TIBER TAP-TIBER		1,084,858						1,084,858		
100	UTICA JCT-SIOUX FALLS		3,496,153						3,496,153		
101	VALLEY CITY-FORMAN		1,527,895						1,527,895		
102	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM		312,931						312,931		
103	WATERTOWN-GRANITE FALLS 1&2		5,269,587						5,269,587		
104	WATERTOWN-SIOUX CITY		26,679,769						26,679,769		
105	WATFORD CITY-BEULAH		1,401,905						1,401,905		
106	WILLISTON-WATFORD CITY		563,079						563,079		
107	WM. J. NEAL-RUGBY		4,629,316						4,629,316		
108	YELLOWTAIL-CUSTER		2,265,163						2,265,163		
109	Subtotal		412,025,231		0		0		412,025,231		
110											
111	Substations										
112	ARMOUR SUBSTATION		1,868,644		(82,000)				1,786,644		
113	ASH SUBSTATION		63,325						63,325		
114	AURORA SUBSTATION		2,899,881						2,899,881		
115	BELDEN SUBSTATION		164,986.20						164,986		
116	BELFIELD SUBSTATION		10,138,776						10,138,776		
117	BERESFORD SUBSTATION		3,494,954		(594,142)				2,900,812		17% of the costs of this facility have been allocated to distribution.
118	BISBEE SUBSTATION		272,529		(136,265)				136,264		50% of the costs of this facility have been allocated to distribution
119	BISMARK SUBSTATION		8,110,398						8,110,398		
120	BISON		12,472						12,472		
121	BOLE SUB (BEFP)		92,092						92,092		
122	BOLE SUB (BEPS)		3,111,717						3,111,717		
123	BONESTEEL SUBSTATION		3,442,909		(1,721,454)				1,721,455		50% of the costs of this facility have been allocated to distribution.

Line No.	(1) DESCRIPTION	a	(2) FY2009 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
124	BROOKINGS SUBSTATION		3,880,456						3,880,456		
125	CARPENTER SUBSTATION		2,398,390						2,398,390		
126	CARRINGTON SUBSTATION		3,756,722		(488,374)				3,268,348		13% of the costs of this facility have been allocated to distribution.
127	CIRCLE SUBSTATION		1,507,470						1,507,470		
128	CONRAD SUB		311,656						311,656		
129	CONRAD SUB (BEPS)		5,008,913						5,008,913		
130	CRESTON SUBSTATION		4,941,437		(55,000)				4,886,437		
131	CROSSOVER SUB (BEFP)		267,232						267,232		
132	CROSSOVER SUB		10,955,346						10,955,346		
133	CUSTER SUBSTATION (BEFP)		3,189,683						3,189,683		
134	CUSTER SUBSTATION		1,322,622						1,322,622		
135	CUSTER TRAIL SUBSTATION		1,475,222		(737,611)				737,611		50% of the costs of this facility have been allocated to distribution
136	DAWSON COUNTY SUBSTATION		10,804,980		(864,398)				9,940,582		8% of the costs of this facility have been allocated to distribution.
137	DENISON SUBSTATION		15,717,046						15,717,046		
138	DEVAUL SUBSTATION		905,869		(543,522)				362,347		60% of the costs of this facility have been allocated to distribution
139	DEVILS LAKE SUBSTATION		2,591,935		(285,113)				2,306,822		11% of the costs of this facility have been allocated to distribution
140	EAGLE BUTTE SUBSTATION		1,252,804						1,252,804		
141	EDGELEY SUBSTATION		3,477,612		(486,866)				2,990,746		14% of the costs of this facility have been allocated to distribution
142	ELK CREEK SUBSTATION		2,078,657						2,078,657		
143	ELLENDALE SUBSTATION		579 43		(579)				0		
144	ENDERLIN TAP STATION		730,428						730,428		
145	EXIRA SWITCHING STATION		5,500,776						5,500,776		
146	FAITH SUBSTATION		1,212,383		(606,191)				606,192		50% of the costs of this facility have been allocated to distribution.
147	FARGO SUBSTATION		20,561,012		(47,000)				20,514,012		
148	FLANDREAU SUBSTATION		3,393,392		(576,877)				2,816,515		17% of the costs of this facility have been allocated to distribution
149	FORMAN SUBSTATION		5,456,548		(709,351)				4,747,197		13% of the costs of this facility have been allocated to distribution.
150	FORT RANDALL		253,710						253,710		
151	FORT THOMPSON #2		8,472,673						8,472,673		
152	FORT THOMPSON SUBSTATION		14,537,019		(354,000)				14,183,019		
153	GLENDIVE SUBSTATION		1,725,310						1,725,310		
154	GRAND FORKS SUBSTATION		9,329,992						9,329,992		
155	GRAND ISLAND SUBSTATION		11,912,281						11,912,281		
156	GRANITE FALLS SUBSTATION		18,720,615		(57,000)				18,663,615		
157	GREAT FALLS SUB (BEFP)		87,834						87,834		
158	GREAT FALLS SUB		470,826						470,826		
159	GREGORY SUBSTATION		1,526,856		(305,371)				1,221,485		20% of the costs of this facility have been allocated to distribution
160	GROTON SUBSTATION		3,880,549						3,880,549		
161	HAVRE SUBSTATION		5,668,800		(963,696)				4,705,104		17% of the costs of this facility have been allocated to distribution.
162	HILKEN SUSTATION		3,874,407						3,874,407		
163	HURON SUBSTATION		10,935,738						10,935,738		
164	JAMESTOWN SUBSTATION		18,212,205		(1,821,221)				16,390,984		10% of the costs of this facility have been allocated to distribution.
165	KILLDEER SUBSTATION		434,273						434,273		
166	LAKOTA SUBSTATION		2,756,210		(909,549)				1,846,661		33% of the costs of this facility have been allocated to distribution
167	LEEDS SUBSTATION		1,465,204		(205,129)				1,260,075		14% of the costs of this facility have been allocated to distribution
168	LETCHER SUBSTATION		10,097,632						10,097,632		
169	MARTIN SUBSTATION		1,533,848						1,533,848		
170	MAURINE SUBSTATION		5,662,288						5,662,288		
171	MIDLAND SUBSTATION		672,772						672,772		
172	MILES CITY #2		4,634,218						4,634,218		
173	MILES CITY #2 (BEFP)		986,001						986,001		
174	MILES CITY SUB #3		1,669,005						1,669,005		
175	MILES CITY SUB #3 (BEFP)		226,697						226,697		
176	MILES CITY SUBSTATION (BEFP)		160,336						160,336		
177	MILES CITY SUBSTATION		714,993						714,993		
178	MISSION SUBSTATION		3,156,994						3,156,994		
179	MORRIS SUBSTATION		7,114,391						7,114,391		
180	MT VERNON SUBSTATION		1,896,247						1,896,247		
181	NEW UNDERWOOD SUBSTATION		7,296,806		(802,649)				6,494,157		11% of the costs of this facility have been allocated to distribution.
182	NEWELL SUBSTATION		1,154,996						1,154,996		
183	Non-Facility		412,629						412,629		
184	O'FALLON CREEK SUBSTATION		1,986,758		(993,379)				993,379		50% of the costs of this facility have been allocated to distribution.
185	PHILIP SUBSTATION		1,974,602						1,974,602		
186	PIERRE SUBSTATION		4,471,691		(2,235,846)				2,235,845		50% of the costs of this facility have been allocated to distribution

Line No.	(1) DESCRIPTION	a	(2) FY2009 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
187	RAINBOW SUBSTATION		723,556						723,556		
188	RAPID CITY SUBSTATION		4,804,631						4,804,631		
189	RICHLAND SUBSTATION		1,555,034		(1,244,027)				311,007		80% of the costs of this facility have been allocated to distribution.
190	ROLLA SUBSTATION		830,427		(207,607)				622,820		25% of the costs of this facility have been allocated to distribution
191	RUDYARD SUBSTATION		2,585,060		(439,460)				2,145,600		17% of the costs of this facility have been allocated to distribution
192	RUGBY SUBSTATION		5,885,813		(824,014)				5,061,799		14% of the costs of this facility have been allocated to distribution
193	SAVAGE SUB		74,403						74,403		
194	SHELBY SUBSTATION		1,086,199						1,086,199		
195	SHELBY SUBSTATION #2 (BEFP)		286,340						286,340		
196	SHELBY SUBSTATION #2 (BEPS)		4,134,102						4,134,102		
197	SIOUX CITY #2		9,444,471						9,444,471		
198	SIOUX CITY SUBSTATION		15,655,346		(57,000)				15,598,346		
199	SIOUX FALLS SUBSTATION		6,520,157						6,520,157		
200	SPENCER		3,240,715						3,240,715		
201	SULLY BUTTES		74,428						74,428		
202	SUMMIT SUBSTATION		2,873,211						2,873,211		
203	TYNDALL SUBSTATION		842,578						842,578		
204	UTICA JCT.		13,007,047						13,007,047		
205	VALLEY CITY SUBSTATION		3,066,265						3,066,265		
206	VERONA		25,210						25,210		
207	VIRGIL FODNESS SUBSTATION		3,206,763						3,206,763		
208	WALL SUBSTATION		1,609,013		(804,506)				804,507		50% of the costs of this facility have been allocated to distribution.
209	WARD SUBSTATION		3,451,262						3,451,262		
210	WASHBURN SUBSTATION		1,972,344						1,972,344		
211	WATERTOWN #2		2,965,204						2,965,204		
212	WATERTOWN STATIC VAR SYSTEM		11,703,689						11,703,689		
213	WATERTOWN SUBSTATION		13,118,030						13,118,030		
214	WATFORD CITY SUB		1,539,705		(30,000)				1,509,705		
215	WESSINGTON SPRINGS SUBSTATION		4,051,147						4,051,147		
216	WHATELY (NORTHERN)		40,860						40,860		
217	WHATELY SUBSTATION		109,910		(54,955)				54,955		50% of the costs of this facility have been allocated to distribution
218	WHITE 345/115 SUB		9,658,497						9,658,497		
219	WICKSVILLE SUBSTATION		683,282		(341,641)				341,641		50% of the costs of this facility have been allocated to distribution.
220	WILLISTON SUBSTATION		6,684,168						6,684,168		
221	WINNER SUBSTATION		3,361,424		(1,680,712)				1,680,712		50% of the costs of this facility have been allocated to distribution.
222	WOLF POINT SUBSTATION		7,230,798		(2,169,239)				5,061,559		30% of the costs of this facility have been allocated to distribution.
223	WOONSOCKET SUBSTATION		2,378,168						2,378,168		
224	YANKTON SUBSTATION		53,583						53,583		
225	Subtotal		466,992,099		(24,435,744)		0		442,556,355		
226											
227	Line Taps & Related Equipment										
228	ANITA		6,259						6,259		
229	ASSINNIBOINE		35,005						35,005		
230	BAKER (BEFP)		133,554						133,554		
231	BAKER		97,832						97,832		
232	CANYON FERRY (BEFP)		15,145						15,145		
233	CANYON FERRY		30,065						30,065		
234	CHARLIE CREEK		1,121,015						1,121,015		
235	COTTON		1,399						1,399		
236	DENBIGH TAP		848,872						848,872		
237	DICKINSON		63,736						63,736		
238	E. J. MANNING		49,112						49,112		
239	EAGLE		156,285						156,285		
240	FORSYTH		32,070						32,070		
241	FORSYTH		273,368						273,368		
242	HARLEM		174,745						174,745		
243	HARLEM (BEFP)		16,015						16,015		
244	HETTINGER		4,451						4,451		
245	HIGHWOOD		22,896						22,896		
246	MALLARD		29,969						29,969		
247	MALTA		151,936						151,936		
248	NASHUA SUB		72,368						72,368		
249	O'NEILL SUB (NPP)		115,790						115,790		

Line No.	(1) DESCRIPTION		(2) FY2009 TOTALS		(3) MISCELLANEOUS ADJUSTMENTS		(4) GENERATION ADJUSTMENTS		(5) TRANSMISSION TOTALS		(6) SOURCE/NOTES
		a		b		c		d		e	
250	PENN TAP		$90,607						$90,607		
251	POPLAR (MDU)		3,758						3,758		
252	SHIRLEY TAP		22,102						22,102		
253	STANLEY		49,735						49,735		
254	TERRY TAP		78,497						78,497		
255	TERRY TAP		345,850		(172,925)				172,925		50% of the costs of this facility have been allocated to distribution
256	TIBER TAP		166,306		(83,153)				83,153		50% of the costs of this facility have been allocated to distribution
257	VETAL TAP		232,375						232,375		
258	V. T. HANLON		5,553						5,553		
259	WM. J. NEAL		166,336						166,336		
260	YANKTON JCT.		28,526						28,526		
261	ZENITH		2,047						2,047		
262		Subtotal	5,443,580		(256,078)		0		5,187,502		
263											
264	O&M Service & Maintenance Centers										
265	ARMOUR O&M SER. CEN.		3,488,667						3,488,667		
266	BISMARCK O&M SER. CEN.		8,969,071						8,969,071		
267	DAWSON SER. CEN.		22,545						22,545		
268	DEVILS LAKE O&M SER. CEN.		3,852,064						3,852,064		
269	Fargo Line Maintenance Facility		964,929						964,929		
270	FARGO O&M SER. CEN.		794,673						794,673		
271	FORT PECK SER. CEN		5,793,310						5,793,310		
272	FORT THOMPSON O&M S. C.		315,000						315,000		
273	HAVRE SERVICE CENTER		249,377						249,377		
274	HURON O&M SER. CEN.		2,447,467						2,447,467		
275	JAMESTOWN O&M SER. CEN		3,841,398						3,841,398		
276	MILES CITY MTCE FAC.		21,817						21,817		
277	MILES CITY MTCE FAC.		1,003,437						1,003,437		
278	NEW UNDERWOOD SER. CEN.		96,884						96,884		
279	PHILIP O&M SER. CENT.		1,690,034						1,690,034		
280	PIERRE O&M SER. CEN.		1,047,818						1,047,818		
281	RAPID CITY GARAGE & STOR.		2,055,932						2,055,932		
282	SIOUX CITY O&M SER. CEN.		3,007,882						3,007,882		
283	SIOUX FALLS O&M SER. CEN.		313,280						313,280		
284	WATERTOWN MAINT. CEN.		934,402						934,402		
285		Subtotal	40,909,988		0		0		40,909,988		
286											
287	Operation Centers										
288	WATERTOWN OPERATIONS CENT		861,149				(269,109)		592,040		
289	WATERTOWN OPER CTR (BFPS)		10,862,172				(3,394,429)		7,467,743		Column 4 shows 31.25% of the Watertown Operations Center that was prorated to generation based on FTE associated with generation
290		Subtotal	11,725,321		0		(3,663,538)		8,059,783		
291											
292	Mobile Equipment										
293	MOB 115KV SWITCH TRAILER		12,328						12,328		
294	MOB 115KV SWITCH TRAILER		57,413						57,413		
295	MOB TRANSF 111KV 15MVA		213,000						213,000		
296	MOB TRANSF 115KV 10MVA		76,258						76,258		
297	MOB TRANSF 115KV 10MVA		142,235						142,235		
298	MOB TRANSF 115KV 25MVA		556,464						556,464		
299	MOB TRANSF 115KV 40MVA		499,220						499,220		
300	MOB TRANSF 230KV 1-33MVA		170,278						170,278		
301	MOB TRANS		248,943						248,943		
302	MOBILE BY PASS KIT (BISMARCK)		35,071						35,071		
303	MOBILE BY PASS KIT (HURON)		163,695						163,695		
304	MOBILE CAPACITOR BANK		19,075						19,075		
305	MOBILE SUB 110KV		127,144						127,144		
306	MOBILE SUB 115KV 20MVA		404,166						404,166		
307	MOBILE SUB 41.8 KV		192,498						192,498		
308	MOBILE SUB 69KV		71,118						71,118		
309	MOB SH.REACTOR		179,328						179,328		
310		Subtotal	3,168,233		0		0		3,168,233		
311											
312	Transmission-Related Generation Facilities										

Line No.	(1) DESCRIPTION	(2) FY2009 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
	a	b	c	d	e	
313	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
314	CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
315	CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
316	FORT PECK POWERPLANT (COE)	8,380		(8,380)	0	
317	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
318	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
319	Subtotal	1,985,311	0	(1,985,311)	0	
320						
321	Communication Facilities					
322	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.
323	BAKER RELAY	27,791		(8,801)	18,990	
324	BANTRY	268,530		(85,044)	183,486	
325	BARRETT	244,695		(77,495)	167,200	
326	BATTLE MT. MICROWAVE	470,739		(149,083)	321,656	
327	BELLE PRAIRIE	16,111		(5,102)	11,009	
328	BELLE PRAIRIE	577,323		(182,838)	394,485	
329	BENEDICT	36,772		(11,646)	25,126	
330	BEULAH	10,679		(3,382)	7,297	
331	BIG BEND	113,362		(35,902)	77,460	
332	BIJOU REPEATER	603,315		(191,070)	412,245	
333	BISMARCK REPEATER	405,324		(128,366)	276,958	
334	BISON REPEATER	204,957		(64,910)	140,047	
335	BOLE NORTH REPEATER	149,228		(47,260)	101,968	
336	BRINSMADE	237,551		(75,232)	162,319	
337	BRISTOL	11,441		(3,623)	7,818	
338	BRUNSVILLE REPEATER	92,595		(29,325)	63,270	
339	BUFFALO	255,051		(80,775)	174,276	
340	CAHOON	240,466		(76,156)	164,310	
341	CARRINGTON REPEATER	726,855		(230,195)	496,660	
342	CHARTER OAK REPEATER	12,546		(3,973)	12,546	
343	CHARTER OAK REPEATER	3,121		(988)	3,121	
344	CHINOOK (BEPP)	284,048		(89,958)	194,090	
345	CHINOOK REPEATER	15,293		(4,843)	10,450	
346	CLARK MW REPEATER	588,027		(186,228)	401,799	
347	CLEVELAND REPEATER, N D	263,617		(83,488)	180,129	
348	COLEMAN REPEATER	105,281		(33,342)	71,939	
349	COLOME REPEATER	469,005		(148,534)	320,471	
350	CONRAD BUTTE REPEATER	371,283		(117,585)	253,698	
351	CONRAD BUTTE REPEATER	84,384		(26,725)	57,659	
352	CRESTON REPEATER	11,107		(3,517)	7,590	
353	CROW LAKE REPEATER	311,803		(98,748)	213,055	
354	CROWN BUTTE	202,445		(64,114)	138,331	
355	CULBERTSON RADIO RELAY SITE	1,926		(610)	1,316	
356	CUSTER LOOKOUT	194,017		(61,445)	132,572	
357	DALTON (WES)	198,021		(62,713)	135,308	
358	DEVILS LAKE REPEATER	467,927		(148,192)	319,735	
359	DODSON REPEATER	276,812		(87,666)	189,146	
360	DOGDEN BUTTE	281,286		(89,083)	192,203	
361	DRISCOLL	196,774		(62,318)	134,456	
362	DUPREE REPEATER	1,821		(577)	1,244	
363	DUTTON REPEATER	315,739		(99,995)	215,744	
364	EAST RAINY BUTTE	287,358		(91,000)	196,339	
365	ECKELSON	288,401		(91,337)	197,064	
366	ELKTON	146,696		(46,459)	100,237	
367	ELLENDALE REPEATER	319,122		(101,066)	218,056	
368	ELLSWORTH AIR BASE	59,669		(18,897)	40,772	
369	ERHARD	301,774		(95,572)	206,202	
370	EXIRA REPEATER	2,527		($00)	1,727	
371	F. L. BLAIR	103,372		(32,738)	70,634	
372	FAIRPOINT REPEATER	339,030		(107,371)	231,659	
373	FALLON REPEATER	271,939		($6,123)	185,816	
374	FERGUS FALLS COMMUNICATIONS SITE	485,567		(153,779)	331,788	
375	FLOWING WELLS	68,763		(21,777)	46,986	

Line No.	(1) DESCRIPTION	a	(2) FY2009 TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
376	FORBES COMMUNICATION SITE		45,316				(14,352)		30,964		
377	FORT PECK RELAY (WES)		250,960				(79,479)		171,481		
378	FORT THOMPSON REPEATER		306,861				(97,183)		209,678		
379	FORT THOMPSON REPEATER (EAST RIVER)		301,614				(95,521)		206,093		
380	FOX CREEK MICROWAVE		579,063				(183,389)		395,674		
381	FRYBURG SUB & MICROWAVE		210,967				(66,813)		144,154		
382	GARRISON		249,702				(79,081)		170,621		
383	GARY REPEATER		228,494				(72,364)		156,130		
384	GAVIN'S POINT		46,061				(14,588)		31,473		
385	GAVINS POINT REPEATER		411,445				(130,305)		281,140		
386	GETTYSBURG REPEATER		296,476				(93,894)		202,582		
387	GLENHAM		293,701				(93,015)		200,686		
388	GRAND FORKS MINNKOTA (MPC)		23,847				(7,552)		16,295		
389	HAILSTONE BUTTE		188,523				(59,705)		128,818		
390	HALLOWAY REPEATER		266,614				(84,437)		182,177		
391	HATHAWAY		17,314				(5,483)		11,831		
392	HATHAWAY		191,777				(60,736)		131,041		
393	HERMOSA MICROWAVE		302,701				(95,865)		206,836		
394	HIGHLAND REPEATER		177,964				(56,361)		121,603		
395	HIGHMORE REPEATER		251,511				(79,654)		171,857		
396	HINSDALE		201,837				(63,922)		137,915		
397	HINSDALE REPEATER		25,153				(7,966)		17,187		
398	HOPEWELL REPEATER		391,934				(124,126)		267,808		
399	HUNTER MICROWAVE		307,546				(97,400)		210,146		
400	HURON DISTRICT OFFICE		747,055				(236,592)		510,463		
401	HYSHAM		250,143				(79,220)		170,923		
402	JAMESTOWN REPEATER		46,981				(14,879)		32,102		
403	JONES CREEK		251,034				(79,502)		171,532		
404	KELLY CREEK		15,210				(4,817)		10,393		
405	KELLY CREEK		300,278				(95,098)		205,180		
406	KILLDEER REPEATER		369,183				(116,920)		252,263		
407	KNEE HILL MW		308,285				(97,634)		210,651		
408	KNEE HILL MW		119,303				(37,783)		81,520		
409	KONES CORNER REPEATER		470,207				(148,915)		321,292		
410	LAC QUI PARLE		747,619				(236,771)		510,848		
411	LAKE ANDES REPEATER		648,460				(205,367)		443,093		
412	LEFOR		186,943				(59,205)		127,738		
413	LINDSAY RIDGE		235,489				(74,579)		160,910		
414	LINTON COMMUNICATIONS SITE		339,867				(107,636)		232,231		
415	LODGEPOLE REPEATER		186,559				(59,083)		127,476		
416	MALTA REPEATER		289,599				(91,716)		197,883		
417	MANDAN MICROWAVE SITE		69,988				(22,165)		47,823		
418	MAPLE RIVER		172,792				(54,723)		118,069		
419	MARTIN REPEATER		287,916				(91,183)		196,733		
420	MAYVILLE		331,361				(104,942)		226,419		
421	MIDLAND REPEATER		660,339				(209,129)		451,210		
422	MILES CITY SUB (BEFP)		305,418				(96,726)		208,692		
423	MOE REPEATER		129,266				(40,939)		88,327		
424	MOORHEAD		251,422				(79,625)		171,797		
425	MORRIS REPEATER & MICROWAVE		331,303				(104,924)		226,379		
426	NEWCASTLE REPEATER		216,330				(68,512)		147,818		
427	OAHE		558,997				(177,034)		381,963		
428	O'KREEK REPEATER		508,754				(161,122)		347,632		
429	ORCHARD REPEATER		43,642				(13,821)		29,821		
430	OTO MICROWAVE		16,445				(5,208)		11,237		
431	OTTUMWA ROAD REPEATER SITE		7,685				(2,434)		5,251		
432	PAGE N.D.		1,646				(521)		1,125		
433	PAHOJA SUB		66,444				(21,043)		45,401		
434	PEAK		264,351				(83,720)		180,631		
435	PHILIP JCT. REPEATER		545,125				(172,641)		372,484		
436	PINE RIDGE		15,766				(4,993)		10,773		
437	PINE RIDGE		273,894				(86,742)		187,152		
438	PRIMGHAR REPEATER		11,990				(3,797)		8,193		

Line No.	(1) DESCRIPTION	(2) FY2009 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
	a	b	c	d	e	
439	PUKWANNA REPEATER	258,360		(81,823)	176,537	
440	RAPID CITY REPEATER	354,281		(112,201)	242,080	
441	RICHARDSON COULEE	214,752		(68,012)	146,740	
442	RICHARDSON COULEE REPEATER	24,536		(7,771)	16,765	
443	RICHLAND MW REPEATER (BEPS)	532,827		(168,746)	364,081	
444	ROCKY RIDGE REPEATER	226,934		(71,870)	155,064	
445	ROLLAG	172,922		(54,764)	118,158	
446	RUGBY REPEATER	276,659		(87,618)	189,041	
447	RUTLAND	388,869		(123,155)	265,714	
448	SACO	1,237		(392)	845	
449	SENTINEL BUTTE	215,321		(68,192)	147,129	
450	SHEEP COULEE REPEATER	475,744		(150,668)	325,076	
451	SIOUX CITY REPEATER	576,462		(182,566)	393,896	
452	SIOUX FALLS REPEATER	367,833		(116,493)	251,340	
453	SIOUX PASS	1,366		(433)	933	
454	SNAKE BUTTE REPEATER	729,560		(231,052)	498,508	
455	SPALDING REPEATER	38,651		(12,241)	26,410	
456	SPIRIT MOUND	226,293		(71,667)	154,626	
457	STRASBERG	17,870		(5,659)	12,211	
458	SUMMIT REPEATER	50,053		(15,852)	34,201	
459	TAPPEN COMMUNICATIONS SITE	291,767		(92,403)	199,364	
460	TAPPEN REPEATER	272,393		(86,267)	186,126	
461	TENNANT COMMUNICATIONS SITE	8,782		(2,781)	6,001	
462	TORONTO REPEATER	106,096		(33,601)	72,495	
463	TRIPP REPEATER	232,264		(73,558)	158,706	
464	TURKEY RIDGE REPEATER	631,991		(200,152)	431,839	
465	TYLER REPEATER	449,771		(142,443)	307,328	
466	VICTOR (EREC)	35,530		(11,252)	24,278	
467	VIDA	14,357		(4,547)	9,810	
468	VIDA	323,156		(102,343)	220,813	
469	WALL REPEATER	461,034		(146,010)	315,024	
470	WATERTOWN REPEATER	699,939		(221,671)	478,268	
471	WAYSIDE	118,156		(37,420)	80,736	
472	WESSINGTON SPGS. REPEATER	623,475		(197,455)	426,020	
473	WESTFIELD	19,003		(6,018)	12,985	
474	WHITE SWAN	116,529		(36,905)	79,624	
475	WHITLOCK (BCPS)	165,594		(52,444)	113,150	
476	WOLBACH REPEATER	52,848		(16,737)	36,111	
477	YELLOWTAIL SWITCHYARD (BEPS)	271,476		(85,976)	185,500	
478	Subtotal	38,235,629	0	(12,109,223)	26,126,406	
479						
480	Miles City Converter Station					
481	MILES CITY CONVERTER STATION	22,557,875			22,557,875	
482	MILES CITY CONVERTER STATION	382,455			382,455	
483	Subtotal	22,940,330	0	0	22,940,330	
484						
485	Distribution Facilities					
486	BUFORD TRENTON TAP - BUFORD TRENTON P P	650,001	(650,001)		0	
487	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	These facilities have been determined to be used solely for distribution
488	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	and are therefore not recovered in the transmission rate
489	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
490	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
491	FORT PECK-WOLF POINT	190,500	(190,500)		0	
492	FRAZER PUMP SUB	253,597	(253,597)		0	
493	GARRISON-SNAKE CREEK	569,241	(569,241)		0	
494	GLENDIVE P P. #1 SUB	425,706	(425,706)		0	
495	INTAKE SUBSTATION	108,040	(108,040)		0	
496	INTAKE-INTAKE PUMP	6,494	(6,494)		0	
497	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
498	SHIRLEY PUMP SUBSTATION	127,053	(127,053)		0	
499	SNAKE CREEK PUMP SUBSTATI	662,435	(662,435)		0	
500	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
501	TIBER DAM SUBSTATION	318,568	(318,568)		0	

Line No.	(1) DESCRIPTION	(2) FY2009 TOTALS TOTALS	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS GEN ADJ	(5) TRANSMISSION TOTALS TRANS TOTAL	(6) SOURCE/NOTES
		a	b	c	d	e
502	WIOTA SUBSTATION	38,507	(38,507)		0	
503	Subtotal Distribution Facilities	4,532,013	(4,532,013)	0	0	
504						
505	Subtotal Upper Great Plains Region Facilities	1,007,955,735	(29,223,835)	(17,758,072)	960,973,828	
506						
507						
508						
509	Rocky Mountain Region Facilities					
510	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1. These are RMR facilities utilized by both RMR and UGPR. The amount in Column 5 will be recovered by UGPR.
511	STEGALL SUBSTATION	8,932,477.75	($8,629,869)		302,609	
512	STEGALL-WAYSIDE	2,978,205			2,978,205	
513	YELLOWTAIL SWITCHYARD	11,136,950	($8,352,713)		2,784,237	
514		23,335,469	(16,982,582)	0	6,352,887	
515						
516	Corps of Engineers Facilities					
517	CORPS SWITCHYARD FACILITIES	29,782,666		(29,782,666)	0	
518		29,782,666	0	(29,782,666)	0	
519						
520	TOTAL FACILITIES	1,061,073,870	(46,206,417)	(47,540,738)	967,326,715	

Basin Electric's Transmission Cost Data

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

Projections for 2011

Line No.			Total	Allocator	Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	**GROSS REVENUE REQUIREMENT** (page 3, line 28)				$ 80,809,944	$ 46,018,647	$ 9,169,061	$ 25,622,237
	(MBPP West Excluded - 1-.065997)						$ 8,563,930	
	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)				$ 45,783,179	$ 605,131	$ 25,622,237
7	**TOTAL REVENUE REQUIREMENT WITH MBPP EAST**					$ 46,388,310		

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

Projections for 2011

	(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, L 1, C. e	3,089,817,764	NA	0.000%	-	NA	0.000%	-	-	-
2	Transmission	Worksheet 1, L 2, C.e	695,243,629	DA	100.000%	695,243,629	DA	100.000%	400,036,379	92,267,804	202,939,446
3	Distribution		-	NA	0.000%	-	NA	0.000%	-	-	-
4	General	Worksheet 1, L.3.C. e	137,063,124								
4a	Direct Assign - Transmission (Note B)		40,535,706	DA	100.000%	40,535,706	DA	100.000%	26,264,758	3,235,492	11,035,456
4b	Direct Assign - Production		38,388,859	NA	0.000%	-	NA	0.000%	-	-	-
4c	Other		58,138,559	WS	11.263%	6,548,146	GP	Gross Plant	3,757,738	869,004	1,911,404
5	Intangible	Worksheet 1, L.4. C. e	72,508,060	DA	100.000%	69,100,565	DA	100.000%	32,120,816	2,617,629	34,362,020
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	Worksheet 1, L. 5. C. e	$ 3,994,632,577			$ 811,428,046			$ 462,189,791	$ 98,989,929	$ 250,248,326
				GP			GP	Gross Plant	57.539%	13.271%	29.190%
	ACCUMULATED DEPRECIATION										
7	Production	Worksheet 1, L.6. C. e	1,125,038,825	NA	0.000%	-	NA	0.000%	-	-	-
8	Transmission	Worksheet 1, L. 7, C. e	280,597,227	DA	100.000%	280,597,227	DA	100.000%	185,526,380	53,539,881	41,530,966
9	Distribution		-	NA	0.000%		NA	0.000%			
10	General	Worksheet 1, L. 8. C. e	104,800,140								
10a	Direct Assign - Transmission		28,760,846	DA	100.000%	28,760,846	DA	100.000%	19,294,997	2,573,181	6,892,668
10b	Direct Assign - Production		27,790,909	NA	0.000%		NA	0.000%			
10c	Other		48,248,385	WS	11.263%	5,434,216	GP	Gross Plant	3,126,794	721,175	1,586,248
11	Intangible	Worksheet 1, L. 9. C. e	46,230,724	DA	100.000%	45,700,724	DA	100.000%	21,669,035	1,919,605	22,112,084
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	Worksheet 1, L. 10. C. e	$ 1,556,666,916			$ 360,493,013			$ 229,617,206	$ 58,753,842	$ 72,121,966
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	1,964,778,939	AUTO		-	AUTO		-	-	-
14	Transmission	(line 2- line 8)	414,646,402	AUTO		414,646,402	AUTO		214,509,999	38,727,923	161,408,480
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO				
16	General	(line 4 - line 10)	32,262,984	AUTO		-	AUTO				
16a	Direct Assign	(line 4a - line 10a)	11,774,860	AUTO		11,774,860	AUTO		6,969,761	662,311	4,142,788
16b	Production	(line 4b - line 10b)	10,597,950	AUTO		-	AUTO				
16c	Other	(line 4c - line 10c)	9,890,174	AUTO		1,113,930	AUTO		640,944	147,829	325,156
17	Intangible	(line 5 - line 11)	26,277,336	AUTO		23,399,841	AUTO		10,451,861	698,024	12,249,936
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 2,437,965,661			$ 450,935,033			$ 232,572,585	$ 40,236,087	$ 178,126,360
	WORKING CAPITAL										
19	CWC (Note C)	one eighth of line 9, page 3	9,642,672	DA	100.000%	4,098,749	DA	100.000%	2,356,437	613,941	1,088,371
20	Materials & Supplies Transmission	RUS 2009.12h, Section G, L.4 L.5. C.d	6,155,586	GP	100.000%	6,155,586	GP	Gross Plant	3,541,863	816,908	1,796,816
21	Prepayments (Note C)		-	GP	Gross Plant	-	GP	Gross Plant	-	-	-
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 15,798,258			$ 10,254,335			$ 5,938,300	$ 1,430,849	$ 2,885,187
23	Rate Base		$ 2,453,763,919			$ 461,189,368			$ 238,510,885	$ 41,666,936	$ 181,011,547

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

Projections for 2011

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&15, C.b	25,243,553								
2	Direct Assignment (Note D)	Accounting Records	13,065,544	DA	100.000%	13,065,544	DA	100.000%	8,532,473	3,456,185	1,076,887
3	Other	Accounting Records	12,178,309	TPW	100.000%	12,178,309	TPW	(page 4)	6,893,654	-	5,284,655
4	A&G	Expense Worksheet #3, L.11, C.b	51,697,524			-					
5	Less Regulatory Fees (Note E)	Accounting Records	224,000	NA	0.000%	-	NA	0.000%			
6	Production	Accounting Records	2,178,219	NA	0.000%	-	NA	0.000%			
7	Transmission (Note F)	Accounting Records	1,454,410	DA		1,454,410	DA	100.000%	240,250	646,910	567,250
8	Headquarters		48,040,895	WS	11.263%	6,091,731	GP	Gross Plant	3,505,121	808,434	1,778,176
9	TOTAL O&M (sum lines 1 and 4)		$ 77,141,377			$ 32,789,994			$ 19,171,498	$ 4,911,529	$ 8,706,968
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	Accounting Records	79,000,000								
11	Transmission	Accounting Records	10,526,040	DA	100.000%	10,526,040	DA	100.000%	5,970,093	1,191,436	3,364,511
12	Production	Accounting Records	68,473,960	NA	0.000%		NA	0.000%			
13	General Plant	Accounting Records	11,952,070	NA	0.000%		NA	0.000%			
14	Transmission	Accounting Records	1,623,851	DA	100.000%	1,623,851	DA	100.000%	1,083,302	193,311	347,238
15	Production	Accounting Records	8,500,000	NA	0.000%	-	NA	0.000%			
16	Other General Plant		3,638,219	WS	11.263%	432,299	GP	Gross Plant	248,741	57,370	126,188
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, L.20, C.b	$ 92,889,743			$ 14,481,452			$ 8,205,431	$ 1,507,514	$ 4,768,507
	TAXES OTHER THAN INCOME TAXES										
19	PLANT RELATED										
20	Property total										
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%			
22	Gross Receipts (Note G)	Based on 2009 actual	3,100,000	DA	100.000%	3,100,000	DA	Estimated	2,900,000	-	200,000
23	Production			NA	0.000%	-	NA	0.000%	-	-	-
24	TOTAL OTHER TAXES		$ 3,100,000			$ 3,100,000			$ 2,900,000	$ -	$ 200,000
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 173,131,120			$ 50,371,446			$ 30,276,929	$ 6,419,043	$ 13,675,475
26	Return		$ 161,948,419	WCC	Rate Base	$ 30,438,498	WCC	Rate Base	$ 15,741,718	$ 2,750,018	$ 11,946,762
27	REV. REQUIREMENT (sum lines 25+26)		$ 335,079,539			$ 80,809,944			$ 46,018,647	$ 9,169,061	$ 25,622,237

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
1	Production	Accounting Records	40,196,382					$2,729,706	$446,402	$1,925,629
2	Transmission-East	Accounting Records	217,789							
3	Transmission-West	Accounting Records	446,402	WS	Trans % of total wages	11.263%	Gross Plant	57.539%	13.271%	29.190%
4	Transmission-Allocated	Accounting Records	4,437,546							
5	Distribution		-	TPW	Trans % excluding West			56.606%	0.000%	43.394%
6	Other Transmission		-							
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$45,298,129							

Transmission Wage and Salary Dollar Split

8	IS transmission Plant (p.2.c.6.L.14, 16a, 17)		231,931,641	
9	West (MBPP) Transmission Plant (p.2..c.7.L14, 16a, 17		40,088,258	
10	Other transmission Plant (p.2.c.8 L.14, 16a.17)		177,801,204	
11	Total (sum lines 8 -10)		$449,821,103	
12	Percent of IS to Total Transmission (Note H)	(Line 8/Line 11-9)		56.606%
13	Percent of Other to total Transmission	(Line 10/Line 11-9)		43.394%
14	IS Trans Wage & Salary Dollar (L 4 times L 12)		2,511,917	100.000%
15	West Trans Wage & Salary Dollar (no allocation.)		-	
16	Other Transmission Wage & Salary (L 4 times L 13)		1,925,629	
17	Total Transmission Wage and Salary Allocated (L.4)		$4,437,546	

Weighted Cost of Capital

Note I			Percent	Rate	Weighted cost
Wksht #1	LTD	2,778,453,149	73.58%	5.07%	3.73%
Wksht #1	Equity	997,471,699	26.42%	10.85%	2.87%
		3,775,924,848	100.00%		6.60%

Note
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 $4,260,600 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) net plant ($40,088,257) 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		b Estimated Budget Year 2009	c Average Budget Year 2010	d Estimated Budget Year 2011	e Transmission Adjusted for 2011 Average Balance
	GROSS PLANT IN SERVICE				
1	Production	1,962,496,218	2,446,635,528	3,733,000,000	3,089,817,764
2	Transmission	612,385,875	673,787,258	716,700,000	695,243,629
3	General	129,598,947	131,354,247	142,772,000	137,063,124
4	Intangible	71,683,380	71,683,380	73,332,740	72,508,060
5	TOTAL GROSS PLANT	$ 2,776,164,420	$ 3,323,460,413	$ 4,665,804,740	$ 3,994,632,577
	ACCUMULATED DEPRECIATION				
6	Production	1,040,313,954	1,085,942,527	1,164,135,124	1,125,038,825
7	Transmission	260,994,369	275,397,227	285,797,227	280,597,227
8	General	91,176,582	101,075,646	108,524,633	104,800,140
9	Intangible	44,835,727	45,750,724	46,710,724	46,230,724
10	TOTAL ACCUM. DEPR	$ 1,437,320,632	$ 1,508,166,123	$ 1,605,167,708	$ 1,556,666,916
	NET PLANT IN SERVICE				
11	Production	922,182,264	1,360,693,002	2,568,864,876	1,964,778,939
12	Transmission	351,391,506	398,390,031	430,902,773	414,646,402
13	General	38,422,365	30,278,601	34,247,367	32,262,984
14	Intangible	26,847,653	25,932,656	26,622,016	26,277,336
15	TOTAL NET PLANT	$ 1,338,843,788	$ 1,815,294,289	$ 3,060,637,032	$ 2,437,965,661

	2011 Estimate
Long-term Liabilities	
Long-term debt, net of current portion	$ 2,689,478,705
Obligations under capital lease	
Total Long-term Liabilities	$ 2,689,478,705
Current Liabilities	
Current portion of long-term debt	$ 88,974,444
Total LTD	2,778,453,149
Equity	997,471,699

Basin Electric Power Cooperative
Integrated System Facilities (IS)

IS Facilities Worksheet #2
Average Balances

IS Facilities			12/31/09 Gross Plant	12/31/09 ACCUM DEPR	12/31/09 Net Book Value	2009 Depreciation Expense	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
IS Lines			221,153,263	126,649,988	94,503,275	2,621,181	222,604,721	129,271,169	93,333,552	2,621,181	222,604,721	130,581,759	92,022,962	2,621,181
IS Substations			94,958,174	56,538,657	38,419,517	1,186,002	103,286,328	58,006,856	45,279,472	1,411,722	103,286,328	58,712,717	44,573,611	1,411,722
IS Trans Mntnce Bldgs			17,692,990	12,416,986	5,276,004	663,198	17,692,990	13,080,184	4,612,806	663,198	17,692,990	13,411,783	4,281,208	663,198
IS Microwave			7,322,537	5,312,223	2,010,315	374,813	7,322,537	5,687,035	1,635,502	374,813	7,322,537	5,874,442	1,448,096	374,813
Intangible			30,470,606	20,257,615	10,212,991	857,912	30,470,606	21,115,527	9,355,079	857,912	30,470,606	21,544,483	8,926,123	857,912
Accum Depr Adjustment				(5,522,430)				(5,522,430)				(5,522,430)		
Total			371,597,570	215,653,039	155,944,531	5,703,105	381,377,182	221,638,341	159,738,841	5,928,825	381,377,182	224,602,754	156,774,428	5,928,825
					-									
T3 Neset Sub	10/01/09	9,858,301	8,207,990	56,477	8,151,513	56,477	1,650,311	101,861	1,548,450	45,384	1,650,311	124,552	1,525,758	45,384
Rhame Substation	04/01/10	6,977,217	120,163	-	120,163	-	6,857,054	141,427	6,715,627	141,427	6,857,054	235,711	6,621,343	188,569
Comm-Belfield Rhame Project	04/01/10	1,290,889	-	-	-	-	1,290,889	26,625	1,264,264	26,625	1,290,889	44,374	1,246,514	35,499
Belfield-Rhame 230 kV Line	04/01/10	26,254,111	1,010,576	-	1,010,576	-	25,243,535	520,648	24,722,887	520,648	25,243,535	867,747	24,375,788	694,197
Belfield Substation Addition	04/01/10	1,290,889					1,290,889	26,625	1,264,264	26,625	1,290,889	44,374	1,246,514	35,499
Williston-Tioga 230 kV Line	12/31/10	24,400,000	440,882	-	440,882	-	23,959,118	-	23,959,118	-	23,959,118	335,500	23,623,618	671,000
Williston Substation Transformers	12/31/10	2,200,000					169,231	-	169,231	-	2,200,000	30,250	2,169,750	60,500
Miscellaneous Additions/replacements	2010	5,500,000					2,961,538	27,147	2,934,391	88,229	5,500,000	102,772	5,397,228	151,250
Sully Buttes Reactor	01/25/11	3,000,000									1,845,154	34,904	1,811,250	20,625
Watford City 230/115 kV Transformer	05/01/11	200,000									123,077	987	122,090	1,375
C Creek Sub CP & 345/230 kV Transformer	11/01/11	8,850,000									2,042,308	4,680	2,037,627	40,563
Glenham Shunt Reactor	02/01/11	4,500,000									2,769,231	52,356	2,716,875	30,938
Miscellaneous General Plant Additions	2011	1,100,000									592,308	7,404	584,904	27,500
TransCanada Charlie Creek Cap Banks	12/01/11	3,000,000									461,538	529	461,010	6,675
TransCanada-Philip SB CAP BANK	12/31/11	5,600,000									430,769	-	430,769	-
ND/SD Microwave	12/01/11	4,270,000									656,923	1,369	655,554	17,792
Miscellaneous Upgrades	12/01/11	1,700,000									130,769	150	130,619	300
			9,779,611	56,477	9,723,134	56,477	63,422,564	844,331	62,578,232	848,936	77,044,872	1,887,659	75,157,213	2,027,865
GRAND TOTAL			381,377,182	215,709,516	165,667,666	5,759,582	444,799,746	222,482,673	222,317,073	6,777,761	458,422,054	226,490,413	231,931,641	7,956,690

West (MBPP)			12/31/09 Gross Plant	12/31/09 ACCUM DEPR	12/31/09 Net Book Value	2009 Depreciation Expense	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
West (MBPP) Lines			70,749,575	40,778,311	29,971,264	910,642	70,749,575	41,688,952	29,060,622	910,642	70,749,575	42,144,273	28,605,301	910,642
West (MBPP) Substations			20,718,536	12,522,623	8,195,913	264,719	20,718,536	12,787,342	7,931,194	264,719	20,718,536	12,919,701	7,798,835	264,719
West (MBPP) Trans Mntnce Bldgs			1,254,372	1,007,662	246,711	90,694	1,254,372	1,098,355	156,017	90,694	1,254,372	1,143,702	110,670	90,694
West (MBPP) Microwave			1,981,120	1,275,553	705,567	102,618	1,981,120	1,378,170	602,949	102,618	1,981,120	1,429,479	551,641	102,618
Intangible			2,617,629	1,821,510	796,119	65,397	2,617,629	1,886,907	730,722	65,397	2,617,629	1,919,605	698,024	65,397
Accum Depr Adjustment				(1,531,443)				(1,531,443)				(1,531,443)		
Total			97,321,232	55,874,215	41,447,017	1,434,069	97,321,232	57,308,284	40,012,948	1,434,069	97,321,232	58,025,318	39,295,914	1,434,069
Miscellaneous Additions/replacements	12/01/11	3,051,200					-	-	-	-	459,415	538	458,878	6,992
Miscellaneous Additions/replacements	2010						330,278	2,271	328,007	4,541	330,278	6,812	323,466	9,083
GRAND TOTAL			97,321,232	55,874,215	41,447,017	1,434,069	97,651,510	57,310,554	40,340,956	1,438,610	98,120,925	58,032,668	40,088,257	1,450,144

Basin Electric Power Cooperative

Expense Worksheet #3

		(a) 2010 Estimate	(b) 2011 Estimate
	Expenses - Operations:		
1	Production - Excluding Fuel	88,223,378	87,903,501
2	Production - Fuel	214,573,127	215,572,718
3	Production - Rents	38,282,932	38,996,062
4	Other Power Supply	314,679,436	321,273,588
5	**Sub-Total Operations Exp.**	655,758,873	663,745,869
6			
7	Transmission Operations	18,703,461	20,512,300
8	Transmission Wheeling	15,805,065	36,643,475
9	Subtotal - Transmission	34,508,526	57,155,775
10			
11	Administration	57,409,775	51,897,524
12	**Total Operations Expense**	747,677,174	772,799,168
13			
14	**Expenses - Maintenance:**		
15	Production	98,550,641	136,108,310
16	Transmission	2,301,050	4,731,553
17	General Plant	0	0
18	**Total Maintenance Expense**	100,851,691	140,839,863
19			
20	Depreciation & Amortization	76,978,176	92,889,743
21	Taxes	3,092,889	2,576,472
22	Interest & Other Deductions	89,943,575	72,248,181
		170,014,640	167,714,396
	Total Cost of Electric Service	**1,018,543,505**	**1,081,353,427**

Basin Electric Power Cooperative

Expense Worksheet #3

		(a) 2010 Estimate	(b) 2011 Estimate
	Expenses - Operations:		
1	Production - Excluding Fuel	88,223,378	87,903,501
2	Production - Fuel	214,573,127	215,572,718
3	Production - Rents	38,282,932	38,996,062
4	Other Power Supply	314,679,436	321,273,588
5	**Sub-Total Operations Exp.**	655,758,873	663,745,869
6			
7	Transmission Operations	18,703,461	20,512,300
8	Transmission Wheeling	15,805,065	36,643,475
9	Subtotal - Transmission	34,508,526	57,155,775
10			
11	Administration	57,409,775	51,897,524
12	**Total Operations Expense**	747,677,174	772,799,168
13			
14	**Expenses - Maintenance:**		
15	Production	98,550,641	136,108,310
16	Transmission	2,301,050	4,731,553
17	General Plant	0	0
18	**Total Maintenance Expense**	100,851,691	140,839,863
19			
20	Depreciation & Amortization	76,978,176	92,889,743
21	Taxes	3,092,889	2,576,472
22	Interest & Other Deductions	89,943,575	72,248,181
		170,014,640	167,714,396
	Total Cost of Electric Service	**1,018,543,505**	**1,081,353,427**

Basin Electric's Ancillary Services Cost Data

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2009

Summary

A	Total LOS and AVS Net Plant Investment	$	539,449,310	(ancillary worksheet 1)
B	Facilities with AGC (LOS 1 & AVS)	$	429,935,564	(Ancillary worksheet 1 less LOS 2)
C	B/A		79.6990%	
D	AGC Facilities	$	57,035	
E	AGC Facilities Percentage (D/B)		0.0133%	
F	Generation Revenue Requirement	$	204,800,743	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$	27,169	(E x F)
H	**Regulation Revenue Requirement**	**$**	**84,204**	(D + G)

Basin Electric Power Cooperative
Generation Plant
December 31, 2009

Worksheet #2

	LO #1	LO #2	SM #4	AVS #055	AVS #066	Groton	Trans Groton	LRS #006	LRS #007	LRS #008	DFS	Other 340-347	Total
Gross Plant - Production	100,276,515	223,817,050	24,930,271	643,814,053	210,180,828	125,897,561	1,922,004	186,328,836	174,364,115	206,521,050	646,747	65,719,183	1,964,418,222
Accum Depr - Production	(65,463,807)	(114,252,668)	(23,070,199)	(350,183,445)	(109,382,358)	(8,737,404)	(216,340)	(118,619,152)	(109,556,849)	(126,485,382)	-	(15,024,074)	(1,041,011,680)
Accum Depr - Adjustment	50,352	(50,637)	56,378	414,700	248,719	20,746		(100,282)	(90,603)	(85,772)		17,785	481,386
Net Book	34,843,059	109,513,745	1,916,450	294,045,316	101,047,189	117,180,902	1,705,664	67,609,402	64,716,663	79,949,896	646,747	50,712,895	923,887,928
Gross General Plant	4,176,457	4,176,457	251,844	5,500,977	5,500,977	520,915		2,310,318	2,310,318	2,310,388		387,203	27,455,856
G/P Gross Microwave Alloc	1,629,977	1,629,977	102,192	2,146,908	2,146,908	54,051		53,737	53,737	53,739	431,879	2,629,900	10,933,004
Accum Depr	(2,615,076)	(2,615,076)	(228,813)	(3,476,096)	(3,476,096)	(97,903)		(1,658,543)	(1,658,543)	(1,658,593)		(52,446)	(17,537,184)
Microwave Accum Depr	(1,180,524)	(1,180,524)	(74,013)	(1,554,915)	(1,554,915)	(48,430)		(34,599)	(34,599)	(34,600)	(121,042)	(893,355)	(6,711,516)
Accum Depr Adjust	(538,824)	(538,824)	(33,782)	(709,707)	(709,707)	(67,206)	-	(298,065)	(298,065)	(298,074)	-	(49,955)	(3,542,209)
Net Book	1,472,010	1,472,010	61,210	1,907,167	1,907,167	361,427		372,849	372,849	372,860	310,837	2,021,347	10,597,951
Gross Plant Intangible	-	-	-	524,573	524,573	-		-	-	-		3,181,710	4,230,855
Accum Depr				(107,013)	(107,013)	-						(293,904)	(507,930)
Net Book	-	-	-	417,560	417,560	-		-	-	-		2,887,806	3,722,925
Total Net Plant	36,315,069	110,985,756	1,977,660	296,370,043	103,371,915	117,542,329	1,705,664	67,982,251	65,089,511	80,322,756	957,584	55,622,048	938,208,804

Basin Electric Power Cooperative
Generation Plant
December 31, 2009

Worksheet #7

	LO #1	LO #2	SM #4	AVS #065	AVS #066	Groton	Trans Groton	LRS #006	LRS #007	LRS #008	DFS	Other 340-347	Total
Gross Plant - Production	100,276,515	223,817,050	24,930,271	643,814,063	210,180,828	125,897,561	1,922,004	186,328,836	174,364,115	206,521,050	646,747	65,719,183	1,964,418,222
Accum Depr - Production	(65,483,807)	(114,252,668)	(23,070,199)	(350,183,446)	(109,382,358)	(6,737,404)	(216,340)	(118,619,152)	(109,556,849)	(126,485,382)	-	(15,024,074)	(1,041,011,680)
Accum Depr - Adjustment	50,352	(50,637)	56,378	414,700	248,719	20,746		(100,282)	(90,603)	(85,772)		17,785	481,386
Net Book (RUS 310-347)	**34,843,059**	**109,513,745**	**1,916,450**	**294,045,316**	**101,047,189**	**117,180,902**	**1,705,664**	**67,609,402**	**64,716,663**	**79,949,896**	**646,747**	**50,712,895**	**923,887,928**

Heartland's Transmission Cost Data

Heartland Consumers Power District
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

Heartland Consumers Power District

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 1,045,250
	REVENUE CREDITS	(Note P)				
2	Account No. 454	(page 4, line 30)	24,869	TP	0.52203	$12,982
3	Account No. 456.1	(page 4, line 33)	0	TP	0.52203	0
4	Revenue From Existing Transmission Agreements		22,000	NA	1.00000	22,000
5	Transmission Service Credits		0	NA	1.00000	0
6	TOTAL REVENUE CREDITS					34,982
	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 1,010,268

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

Heartland Consumers Power District

Line No.	(1) RATE BASE:	(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	Schedule A	41,719,984	NA		
2	Transmission	Schedule A	14,599,061	TP	0.52203	7,621,180
3	Distribution		0	NA		
4	General & Intangible	Schedule A	6,352,713	W/S	0.06786	431,123
5	Common		0	CE	0.06786	0
6	TOTAL GROSS PLANT (sum lines 1-5)		62,671,758	GP=	12.848%	8,052,303
	ACCUMULATED DEPRECIATION					
7	Production		30,738,402	NA		
8	Transmission		10,538,880	TP	0.52203	5,501,635
9	Distribution		0	NA		
10	General & Intangible		2,932,975	W/S	0.06786	199,045
11	Common		0	CE	0.06786	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		44,210,257			5,700,679
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	10,981,582			
14	Transmission	(line 2- line 8)	4,060,181			2,119,545
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	3,419,738			232,079
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		18,461,501	NP=	12.738%	2,351,624
	ADJUSTMENTS TO RATE BASE (Note A)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.12738	0
21	Account No. 283 (enter negative)		0	NP	0.12738	0
22	Account No. 190		0	NP	0.12738	0
23	Account No. 255 (enter negative)		0	NP	0.12738	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE (Note B)		0	TP	0.52203	0
	WORKING CAPITAL (Note C)					
26	CWC		420,744			49,567
27	Materials & Supplies (Note B)		0	TE	1.00000	0
28	Prepayments		114,025	GP	0.12848	14,650
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		534,769			64,217
30	RATE BASE (sum lines 18, 24, 25, and 29)		18,996,270			2,415,841

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

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	251,518	TE	1.00000	251,518
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565		71,173	NA	1.00000	71,173
3	A&G (Note G)	Schedule A	3,185,604	W/S	0.06786	216,189
4	Less FERC Annual Fees		0	W/S	0.06786	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.06786	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.06786	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)		3,365,949			396,534
	DEPRECIATION EXPENSE					
9	Transmission		848,400	TP	0.52203	442,892
10	General		230,242	W/S	0.06786	15,625
11	Common		0	CE	0.06786	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		1,078,642			458,517
	TAXES OTHER THAN INCOME TAXES (Note F)					
	LABOR RELATED					
13	Payroll		77,700	W/S	0.06786	5,273
14	Highway and vehicle		0	W/S	0.06786	0
15	PLANT RELATED					
16	Property		160,866	GP	0.12848	20,669
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.12848	0
19	Payments in lieu of taxes		0	GP	0.12848	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		238,566			25,942
	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	0.12738	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)]		1,291,586	NA		164,257
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		5,974,743			1,045,250

Revenue Requirement - Non-Levelized | Revenue Requirement Template
Annual Transmission Revenue Requirement | For the 12 months ending 12/31/2010

Heartland Consumers Power District

SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN IS RATES							
1	Total transmission plant (page 2, line 2, column 3)						14,599,061	
2	Less transmission plant excluded from IS rates (Note H)						6,752,305	
3	Less transmission plant included in OATT Ancillary Services (Note I)						225,576	
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)						7,621,180	
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)					TP=	0.52203	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						251,518	
7	Less transmission expenses included in OATT Ancillary Services (Note J)						0	
8	Included transmission expenses (line 7 less line 6)						251,518	
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	0.52203	
11	Percentage of transmission expenses included in IS Rates (Note K)					TE=	1.00000	
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation			
12	Production		924,498	0.00	0			
13	Transmission		138,144	0.52	72,116			
14	Distribution		0	0.00	0		W&S Allocator	
15	Other		0	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		1,062,642		72,116	=	0.06786	= W/S
	COMMON PLANT ALLOCATOR (CE) (Note L)		$		% Electric		Labor Ratio	
17	Electric		62,671,758		(line 17 / line 20)		(line 16)	CE
18	Gas		0		1.00000	*	0.06786	= 0.06786
19	Water		0					
20	Total (sum lines 17-19)		62,671,758					
	RETURN (R)		$					
21	Long Term Interest	Schedule A	$1,975,956					
			$	%	Cost (Note M)		Weighted	
22	Long Term Debt	Schedule A	36,522,482	80%	5.41%		0.0433	=WCLTD
23	Proprietary Capital	Schedule A	9,089,404	20%	12.38%		0.0247	
24	Total (sum lines 22, 23)		45,611,886	100%			0.0680	=R
25					Proprietary Capital Cost Rate =		12.38%	
26					TIER =		1.26	
	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)						$24,869	
	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 12/31/2010

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

Confidential

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

Missouri River Energy Services

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ 12,222,916
	REVENUE CREDITS	(Note Q)	Total	Allocator		
2	Account No. 454	(page 3, line 34)	0	TP	1.00000	0
3	Account No. 456.1	(page 3, line 37)	202,947	TP	1.00000	202,947
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					202,947
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 12,019,969

Allocation of Net Revenue Requirements by Pricing Zones:	Irv Simmons	OTP	MBPP	Marshall Wind Circuit	Total
Transmission Plant Investment	$ 1,957,786	$ 27,514,314	$ 29,358,631	$ -	$ 58,830,731
% of Total Transmission Plant	3.3%	46.8%	49.9%	0.0%	100.0%
Net Transmission Revenue Requirement (Allocated on Transmission Plant)	$ 396,659	$ 5,621,572	$ 5,997,965	$ -	$ 12,019,969

	DIVISOR			
8	Average of 12 coincident system peaks for requirements (RQ) service		(Note A)	625,690
9	Plus 12 CP of firm bundled sales over one year not in line 8		(Note B)	0
10	Plus 12 CP of Network Load not in line 8		(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)		(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year			0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative)	(Note P)		0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)			0
15	Divisor (sum lines 8-14)			625,690
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ 19.211	
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	$ 1.601	

			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.369		$0.369	
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.074	Capped at weekly rate	$0.053	
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	4.618	Capped at weekly and daily rates	$2.199	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Formula Rate - Cash Flow | Rate Formula Template Utilizing EIA Form 412 Data | For the 12 months ended 12/31/09

Missouri River Energy Services

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note X)		18,645,820	TE	1.0000	18,645,820
1a	Less LSE Expenses included in Transmission O&M Accounts (N		0		1.0000	0
2	Less Account 565		15,124,840		1.0000	15,124,840
3	A&G	VII.13.d	8,801,617	W/S	0.1942	1,709,404
4	Less FERC Annual Fees		0	W/S	0.1942	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		896,335	W/S	0.1942	174,081
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		862,219	TE	1.0000	862,219
6	Common		0	CE	0.1942	0
7	Transmission Lease Payments		0		1.0000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		12,288,481			5,918,521
	DEBT SERVICE					
9a	Debt Service - Transmission Bond Resolution (Note T)		2,214,606		1.0000	2,214,606
9b	Debt Service- Excluding Transmission Bond Resolution (Note U)		23,799,538	GP 2	0.1068	2,542,562
10	Amortization of premium or discount (Note V)		0	GP	0.1748	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		26,014,144			4,757,169
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.1942	0
14	Highway and vehicle		0	W/S	0.1942	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		400,985		1.0000	400,985
16b	Property- General Plant		55,372	GP	0.1748	9,677
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.1748	0
19	Payments in lieu of taxes		0	GP	0.1748	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		456,357			410,662
21	SUBTOTAL (sum lines 8, 11, 20)		38,758,982			11,086,352
22	MARGIN REQUIREMENT (Note H)		6,503,536	GP	0.1748	1,136,564
23	REV. REQUIREMENT (sum lines 21 22)		45,262,518			12,222,916

Formula Rate - Cash Flow | Rate Formula Template Utilizing EIA Form 412 Data | For the 12 months ended 12/31/09

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.	GROSS PLANT IN SERVICE	EIA 412 Reference	Company Total	Allocator		Transmission
1	Production	IV.6.f	280,322,814	NA	0.0000	0
2a	Transmission, excluding separate T	IV.7.f	31,316,417	TP	1.0000	31,316,417
2b	Separate Transmission Project (No	IV.7.f	27,514,314	TP	1.0000	27,514,314
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	22,621,953	W/S	0.1942	4,393,517
5	Common		0	CE	0.1942	0
6	TOTAL GROSS PLANT (sum lines 1-5)		361,775,498	GP	0.1748	63,224,248
6a	Gross Plant Allocator, excluding Separate Transmission Project		334,261,184	GP 2	0.1068	35,709,934
	TRANSMISSION PLANT INCLUDED IN ISO RATES					
7	Total transmission plant (line 2)					58,830,731
8	Less transmission plant excluded from ISO rates (Note J)					0
9	Less transmission plant included in OATT Ancillary Services (Note K)					0
10	Transmission plant included in ISO rates (line 7 less lines 8 & 9)					58,830,731
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)				TP=	1.00000
	TRANSMISSION EXPENSES					
12	Total transmission expenses (page 2, line 1, column 3)					18,645,820
13	Less transmission expenses included in OATT Ancillary Services (Note I)					0
14	Included transmission expenses (line 12 less line 13)					18,645,820
15	Percentage of transmission expenses after adjustment (line 14 divided by line 12)					1.00000
16	Percentage of transmission plant included in ISO Rates (line 11)				TP	1.00000
17	Percentage of transmission expenses included in ISO Rates (line 15 times line 16)				TE=	1.00000
	WAGES & SALARY ALLOCATOR (W&S) (Note L)		$		Allocation	
18	Production		2,260,156	0.00	0	
19	Transmission		566,753	1.00	566,753	
20	Distribution		0	0.00	0	W&S Allocator
21	Other		91,269		0	($ / Allocation)
22	Total (sum lines 18-21)		2,918,179		566,753 =	0.1942
	COMMON PLANT ALLOCATOR (CE) (Note M)		$		% Electric	Labor Ratio
23	Electric		361,775,498		(line 23 / line 26)	(line 22) CE
24	Gas		0		1.00000 *	0.1942 = 0.1942
25	Water		0			
26	Total (sum lines 23-25)		361,775,498			
	FINANCING DATA		$			
27	Long Term Debt	II.33.b +34.b	$216,666,942			
28	Debt Service		26,014,144			
29	Interest on Long Term Debt	III.16.b + III.17.b (Note R)	11,934,781			
30	Bond Principal Amortization (line 28 less line 29)		14,079,363			
	REVENUE CREDITS					Load
	ACCOUNT 447 (SALES FOR RESALE)					
31	a. Bundled Non-RQ Sales for Resale		(Note N)			
32	b. Bundled Sales for Resale included in Divisor on page 1					
33	Total of (a)-(b)					0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)					$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)					
35	a. Transmission charges for all transmission transactions					$202,947
36	b. Transmission charges for all transmission transactions included in Divisor on page 1					$0
37	Total of (a)-(b)					$202,947

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

Missouri River Energy Services

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

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

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
G	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. MRES segregates property taxes between generation, transmission, and general plant based on internal accounting records. Therefore, MRES transmission property taxes are directly assigned to the revenue requirement and general property taxes will be allocated based on the GP allocator. Work papers will be provided."
H	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin. The margin requirement will be allocated on GP.
I	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
J	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6.
M	Enter dollar amounts.
N	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
O	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
P	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
Q	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
R	From Reference II.17.b include only the amount from Account 430.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	Represents only Debt Service that can be directly assigned to transmission assets and no other types of assets. Work papers will be provided.
U	Represents all Debt Service, other than transmission debt service included in line 9a, page 2. Work papers will be provided.
V	The amortization of debt discounts and premiums are excluded since amortization is a non-cash item that does not affect debt service cash flow. The principal and interest payments already reflect all discounts or premiums when the debt was originally issued.
W	Represents only transmission assets that can be directly assigned to the Transmission Service Agreements and no other types of assets. These transmission assets were financed under the Transmission Bond Resolution. Work papers will be provided.
X	Transmission Expense will be the sum of (a) Form 412 VII.8.d and (b) facility credits for the Irv Simmons project in the Integrated System (IS).

NWPS

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/09

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

					Allocated Amount
GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 2,553,769
REVENUE CREDITS	(Note T)	Total	Allocator		
Account No. 454	(page 4, line 34)	165,720	TP	0.81036	134,293
Account No. 456	(page 4, line 37)	86,380	TP	0.81036	69,998
Revenues from Grandfathered Interzonal Transactions		0	TP	0.81036	0
Revenues from service provided by the ISO at a discount		0	TP	0.81036	0
TOTAL REVENUE CREDITS	(sum lines 2-5)				204,291
NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 2,349,478
DIVISOR					
Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	235,917
Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	14,000
Plus 12 CP of Network Load not in line 8				(Note C)	0
Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
Plus Contract Demand of firm P-T-P over one year					0
Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
Divisor (sum lines 8-14)					249,917
Annual Cost ($/kW/Yr)	(line 7 / line 15)	9.401			
Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.783			

		Peak Rate		Off-Peak Rate
Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.181		$0.181
Point-To-Point Rate ($/kW/Day)	(line 16 / 5; line 16 / 7)	0.036	Capped at weekly rate	$0.026
Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 lines 1,000)	2.260	Capped at weekly and daily rates	$1.076
FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
		$0.000	Long Term	$0.000 Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/09

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

(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					
Production	206.42.g	158,992,136	NA		
Transmission	206.53.g	32,799,950	TP	0.81036	26,579,708
Distribution	206.69.g	219,701,382	NA		
General & Intangible	206.5.g & 83.g	9,835,191	W/S	0.04261	419,102
Common	356.1	20,915,117	CE	0.02601	543,941
TOTAL GROSS PLANT (sum lines 1-5)		442,243,776	GP=	6.228%	27,542,749
ACCUMULATED DEPRECIATION					
Production	219.18-22.c	102,313,590	NA		
Transmission	219.23.c	20,710,080	VEst.	72.913%	15,106,085
Distribution	219.24.c	87,301,009	NA		
General & Intangible	219.25.c	2,464,070	W/S	0.04261	105,000
Common	356.1	4,729,590	CE	0.02601	123,003
TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		217,526,338			15,334,088
NET PLANT IN SERVICE					
Production	(line 1- line 7)	56,678,546			
Transmission	(line 2- line 8)	12,089,871			11,473,621
Distribution	(line 3 - line 9)	132,400,373			
General & Intangible	(line 4 - line 10)	7,371,121			314,102
Common	(line 5 - line 11)	16,185,527			420,938
TOTAL NET PLANT (sum lines 13-17)		224,717,438	NP=	5.433%	12,208,661
ADJUSTMENTS TO RATE BASE (Note F)					
Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
Account No. 282 (enter negative)	275.2.k	-41,774,514	NP	0.05433	-2,269,565
Account No. 283 (enter negative)	277.9.k	1,065,318	NP	0.05433	57,878
Account No. 190	234.8.c	-14,654,666	NP	0.05433	-796,173
Account No. 255 (enter negative)	267.8.h	-2,183,567	NP	0.05433	-118,631
TOTAL ADJUSTMENTS (sum lines 19-23)		-57,547,429			-3,126,491
LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.72913	0
WORKING CAPITAL (Note H)					
CWC	calculated	755,467			53,052
Materials & Supplies (Note G)	227.8.c & .15.c	0		1.00000	0
Prepayments (Account 165)	111.46.d	0	GP	0.06228	0
TOTAL WORKING CAPITAL (sum lines 26 - 28)		755,467			53,052
RATE BASE (sum lines 18, 24, 25, & 29)		167,925,475			9,135,223

NWPS

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/09

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

(1)	(2)	(3)	(4)		(5)
	Form No. 1 Page, Line, Col.	Company Total	Allocator		Transmission (Col 3 times Col 4)
O&M					
Transmission	321.100.b	6,033,541	TE	0.81036	5,068,928
Less Account 565	321.88.b	5,092,828		1.00000	5,092,828
A&G	323.168.b	5,703,019	W/S	0.02601	148,319
Less FERC Annual Fees		0	W/S	0.02601	0
Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.02601	0
Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.81036	0
Common	356.1	0	CE	0.02601	0
Transmission Lease Payments		0		1.00000	0
TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		6,043,733			424,419
DEPRECIATION EXPENSE					
Transmission	336.7.b	1,072,556	VRB00	0.72913	871,644
General	336.9.b	626,662	W/S	0.02601	16,298
Common	336.10.b	948,471	CE	0.02601	24,667
TOTAL DEPRECIATION (Sum lines 9 - 11)		2,647,691			912,609
TAXES OTHER THAN INCOME TAXES (Note J)					
LABOR RELATED					
Payroll	262.i	732,029	W/S	0.02601	19,038
Highway and vehicle	262.i	44,426	W/S	0.02601	1,155
PLANT RELATED					
Property	262.i	3,359,658	GP	0.06228	209,238
Gross Receipts	262.i	161,272	NA	zero	0
Other	262.i	207,624	GP	0.06228	12,931
Payments in lieu of taxes		0	GP	0.06228	0
TOTAL OTHER TAXES (sum lines 13 - 19)		4,505,009			242,362
INCOME TAXES	(Note K)				
T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
CIT=(T/1-T) * (1-(WCLTD/R)) =		32.42%			
where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.					
1 / (1 - T) = (from line 21)		1.5385			
Amortized Investment Tax Credit (266.8f) (enter negative)		-456,492			
Income Tax Calculation = line 22 * line 28		4,557,239	NA		247,916
ITC adjustment (line 23 * line 24)		-702,295	NP	0.05433	-38,155
Total Income Taxes	(line 25 plus line 26)	3,854,944			209,761
RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		14,055,362	NA		764,618
REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		31,106,739			2,553,769

NWPS

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/09

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT, Joint Plant Transmission Facilities

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN ISO RATES

Total transmission plant (page 2, line 2, column 3)			32,799,950
Less transmission plant excluded from ISO rates (Note M)			6,220,244
Less transmission plant included in OATT Ancillary Services (Note N)			0
Transmission plant included in ISO rates (line 1 less lines 2 & 3)			26,579,706
Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)		TP=	0.81036

TRANSMISSION EXPENSES

Total transmission expenses (page 3, line 1, column 3)			6,033,541
Less transmission expenses included in OATT Ancillary Services (Note L)			0
Included transmission expenses (line 6 less line 7)			6,033,541
Percentage of transmission expenses after adjustment (line 8 divided by line 6)			1.00000
Percentage of transmission plant included in ISO Rates (line 5)		TP	0.81036
Percentage of transmission expenses included in ISO Rates (line 9 times line 10)		TE=	0.81036

WAGES & SALARY ALLOCATOR (W&S)

	Form 1 Reference	$	TP	Allocation			
Production	354.18.b	470,041	0.00	0			
Transmission	354.19.b	288,963	0.81	234,164			
Distribution	354.20.b	4,198,950	0.00	0	W&S Allocator		
Other	354.21,22,23.b	1,822,621	0.00	0	($ / Allocation)		
Total (sum lines 12-15)		6,781,176		234,164 =	0.03453	=	WS
					0.04261	=	Wsact

COMMON PLANT ALLOCATOR (CE) (Note O)

		$	% Electric		W&S Allocator		
Electric	200.3.c	421,377,251	(line 17 / line 20)		(line 16)		CE
Gas	200.3.d	138,114,915	0.75314	*	0.03453	=	0.02601
Water	200.3.e	0					
Total (sum lines 17 - 19)		559,492,166					

RETURN (R)

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

	$	%	Cost (Note P)			Weighted	
Long Term Debt (112, sum of 16d through 19d)	971,001,062	0.5523	0.0000	0.0603	0.0000	0.0333	=WCLTD
Preferred Stock (112.3d)	0	0.0000	0.0000	0.0000	0.0000	0.0000	
Common Stock (line 26)	787,025,027	0.4477	0.0000	0.1125	0.0000	0.0504	
Total (sum lines 27-29)	1,758,026,089		0.0000	0.0000	0.0000	0.0837	=R

REVENUE CREDITS

			Load
ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note O)	
a. Bundled Non-RQ Sales for Resale (311.x.h)			216,524
b. Bundled Sales for Resale included in Divisor on page 1			216,524
Total of (a)-(b)			0
ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$165,720
ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
a. Transmission charges for all transmission transactions			$211,908
b. Transmission charges for all transmission transactions included in Divisor on Page 1			$125,529
Total of (a)-(b)			$86,380

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/09

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)

Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
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.
Identified in Form 1 as being only transmission related.
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.
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.
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.
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)

Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
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).
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.
Enter dollar amounts
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.
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.
Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
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.
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.