Integrated System Transmission and Ancillary Services Rates

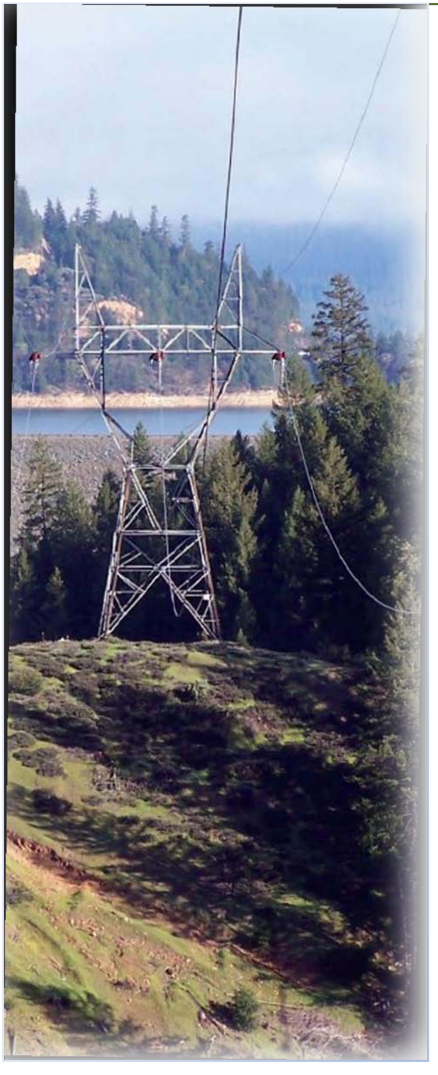
2013 Recalculated Rates

Customer Information Meeting

October 15, 2012

1:30 p.m. MDT, Billings, MT and via Web

Introductions



- Lloyd Linke – Operations Manager
- Ron Klinefelter – Attorney-Advisor
- Linda Cady-Hoffman – Rates Manager
- Steve Sanders – Operations and Transmission Advisor
- Stan Bayley – Public Utilities Specialist

Agenda

1. Meeting Purpose
2. Transmission Rates
3. Ancillary Service Rates
4. Penalty Rate
5. Contact Information

Meeting Purpose

- As a result of the Public Rate Adjustment Process conducted in 2009:
  - Western will provide customers the opportunity to discuss and comment on the recalculated rates by October 31 of each year.
  - Western will respond to customer comments prior to or at the time of the implementation of the recalculated revenue requirements and/or rates.

- This meeting provides an opportunity to discuss the proper application of data in the formula rate, not the rate formula itself.

Forward-Looking Formula Transmission Rates – True-Up

- 2010 - first use of Forward-Looking Formula Transmission Rates.
- Actual audited financial data for 2011 available in 2012.
- True-up of 2011 rates included in the 2013 rates.
- True-up of 2012 rates will be included in 2014 rates.

Formula Rate for Network Transmission Service

- Same ATRR used for Network and Point-to-Point rates.
- Rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed for Transmission.

$$\text{Monthly Charge} = \frac{\text{Customer's Load-Ratio Share } \mathbf{x} \text{ Annual Revenue Requirement for IS Transmission Svc}}{\text{12 months}}$$

Annual Transmission Revenue Requirement

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective January 1, 2013

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$53,400,797	Basin Electric Revenue Requirement Template
5	Western	$118,668,270	Western Revenue Requirement Template
6	Heartland	$814,373	Heartland Revenue Requirement Template
7		$172,883,440	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$3,547,194	MRES Revenue Requirement Template
12		$3,635,778	NWPS Revenue Requirement Template
13		$7,182,972	L11 + L12
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$180,066,412	L7 + L13
19			
20	**2011 True-up Amount**		
21		($3,336,488)	2011 Rate True-up Worksheet
22			
23	**2011 Unreserved Use of Transmission Service Penalties**		
24			
25		($6,344)	2011 Unreserved Use Penalty Worksheet
26			
27	**Annual Revenue Requirement for IS Transmission Service after True-up**		
28			
29		$176,723,580	L18 - L21 - L25

Formula Rate for Firm Point-to-Point IS Transmission Service

- Includes a load projection.
- Rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed for Transmission.

$$\text{Firm Point-to-Point Transmission Rate } \$/kW\text{-}Mo = \frac{\text{Annual IS Transmission Service Revenue Requirement}}{\text{IS Transmission System Total Load}}$$

Firm Point-to-Point Transmission

INTEGRATED SYSTEM

FIRM POINT-TO-POINT RATE DESIGN

Effective January 1, 2013

Line No.			
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$176,723,580	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L29
7			
8	**IS Transmission System Total Load**		
9			
10		5,249,000 KW	IS Transmission System Total Load Estimate
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15	**$2.81/ KW-Mo**		L5 / L10 / 12 months

Formula Rate for Non-Firm Point-to-Point Transmission Service

$$\text{Maximum Non-Firm Point-to-Point Transmission Rate } \textit{m/kWh} = \frac{\text{Firm Point-to-Point Transmission Rate}}{\text{730 hours/month}} \times \text{1000 mills/\$}$$

Non-Firm Point-to-Point Transmission Rate

INTEGRATED SYSTEM

NON-FIRM POINT-TO-POINT RATE DESIGN

Effective January 1, 2013

Line No.			
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$2.81/ KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**3.85 Mills/KWh**	(L5 * 1000) / 730 hours per month

Ancillary Service Rates

- Scheduling, System Control, and Dispatch (SSCD) Service
- Reactive Supply and Voltage Control from Generation Sources Service (RSVC)
- Regulation and Frequency Response Service
- Energy Imbalance Service
- Operating Reserves Service – Spinning and Supplemental
- Generator Imbalance Service

Formula Rate for Scheduling, System Control, and Dispatch Service (SSCD)

- SSCD Rate Formula

$$\textbf{SSCD Service Rate } \textit{per Tag per Day} = \frac{\text{Annual Revenue Requirement SSCD Service}}{\text{Number of Daily Tags per Year}}$$

Formula Rate for Scheduling, System Control, and Dispatch Service (SSCD)

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2013

A.	Fixed Charge Rate	22.258%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,636,553	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,702,964	(A x B)
D.	2011 Number of Daily Tags	87,292	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$42.42**	(C / D)

Fixed Charge Rate for SSCD

Western
AREA POWER
ADMINISTRATION

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	$54,494,799	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$54,494,799	L4 + L5
7			
8	Net Transmission Plant Investment	$560,291,527	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.726%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$15,823,815	A&G Expenses Worksheet, C6L12
16			
17	Net Transmission Plant Investment	$560,291,527	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.824%	L15/L17

Fixed Charge Rate for SSCD (Continued)

20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$26,033,383	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$560,291,527	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.646%	L24/L26
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.		

Fixed Charge Rate for SSCD (Continued)

39			
40			
41	**F. Cost of Capital**		
42			
43	Weighted Transmission Composite Interest Rate	5.062%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.726%	L10
49			
50	A&G Expense	2.824%	L19
51			
52	Depreciation Expense	4.646%	L28
53			
54	Taxes Other than Income Taxes	0.000%	
55			
56	Allocation of General Plant to Transmission	0.000%	
57			
58	Cost of Capital	5.062%	L43
59			
60	Total	22.258%	

Formula Rate for Reactive Supply and Voltage Control From Generation Sources Service

- RSVC Rate Formula

$$\text{RSVC Service Rate } \textit{per kW-Mo} = \frac{\text{Annual Revenue Requirement for VAR Support}}{\text{Load Requiring VAR Support}}$$

Annual Revenue Requirement includes:

- Western's synchronous condenser costs operating outside the 0.95 leading to 0.95 lagging power factor bandwidth.
- Costs of generators providing RSVC Service outside the 0.95 leading to 0.95 lagging power factor bandwidth.

Formula Rate for Reactive Supply and Voltage Control From Generation Sources Service (Cont.)

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2013
(WESTERN'S COSTS)

A.	Fixed Charge Rate	17.846%	(1)
B.	Generation Net Plant Costs ($)	$473,919,619	(2)
C.	Annual Cost of Generation ($)	$84,575,695	(A x B)
D.	Capability Used for Reactive Support (%)	3.11%	(3)
E.	Reactive Service Revenue Requirement	$2,630,304	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2013 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 2007-2011.

Formula Rate for Reactive Supply and Voltage Control From Generation Sources Service (Cont.)

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2013 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,630,304	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,630,304	(A + B)
D.	Over Collection for 2011	($74,773)	(3)
E.	Total Reactive Revenue Requirement with 2011 True-up	$2,555,531	(C + D)
F.	2011 IS Transmission System Total Load (kW-Yr)	4,918,000	(4)
G.	Annual Reactive Charge ($/kW-Yr)	$0.52	(E / F)
H.	Monthly Reactive Charge ($/kW-Mo)	$0.04	(G / 12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2013, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth.

(3) True-up Required for 2011 "True-up for 2011 Reactive Supply and Voltage Control from Generation Sources."

(4) IS Peak Transmission System Load.

Fixed Charge Rate – Reactive Supply and Voltage Control

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	$78,351,000	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$654,099,613	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	11.978%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$308,351	A&G Expenses Worksheet, C6L18
14			
15	Net Generation Plant Investment	$654,099,613	L6
16			
17	A&G as % of Net Generation Plant Investment	0.047%	L13/L15
18			
19			

Fixed Charge Rate – Reactive Supply and Voltage Control (Cont.)

Line	Description	Amount	Source
20	**C. Depreciation Expense for Generation**		
22	Generation Depreciation Expense	$15,137,195	Depreciation Expense Worksheet, C6L6
24	Net Generation Plant Investment	$654,099,613	L6
26	Depreciation as a % of Net Generation Plant Investment	2.314%	L22/L24
29	**D. Taxes Other than Income Taxes for Generation**		
31	Not applicable.		
34	**E. Allocation of General Plant to Generation**		
36	No General Plant identified at this time, all either generation or transmission related.		

Fixed Charge Rate – Reactive Supply and Voltage Control (Cont.)

39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.507%	Cost of Capital Worksheet, C6L11
42			
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	11.978%	L8
47			
48	A&G Expense	0.047%	L17
49			
50	Depreciation Expense	2.314%	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	3.507%	L41
57			
58	Total	17.846%	

Formula Rate for Regulation and Frequency Response Service

- Regulation and Frequency Response Service Rate Formula

$$\text{Regulation Rate } \textit{per kW/Mo} = \frac{\text{Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Regulation and Frequency Response Service

REGULATION AND FREQUENCY RESPONSE FOR 2013
(Western's Costs)

A.	Fixed Charge Rate	15.972%	(1)
B.	Corps Generation Net Plant Costs ($)	$168,890,532	(2)
C.	Annual Corps Generation Cost ($)	$26,975,196	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	$28.79	(C / D)
F.	Capacity Used for Regulation (kW)	63,000	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$1,813,770	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$1,813,770	
J.	Load in Control Area(s) (kW-Yr)	3,150,000	(4)

Regulation and Frequency Response Service (Continued)

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2013

A.	Western Regulation Revenue Requirement	$1,813,770	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$65,242	(2)
C.	Total Regulation Revenue Requirement	$1,879,012	(A + B)
D.	Under Collection - 2011 Regulation Revenue Rqmt	$317,306	(3)
E.	Total Regulation Revenue Rqmt with True-up	2,196,318	(C+D)
F.	Load in Control Area(s) (kW-Yr)	3,150,000	(4)
G.	Regulation Charge ($/kW-Yr)	$0.70	(E / F)
H.	Regulation Charge ($/kW-Mo)	$0.06	(G / 12 months)

Fixed Charge Rate - Regulation and Frequency Response Service

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	$41,886,497	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$421,473,130	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	9.938%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L18
14			
15	Net Corps Generation Plant Investment	$421,473,130	L6
16			
17	A&G as % of Net Generation Plant Investment	0.000%	L13/L15

Fixed Charge Rate - Regulation and Frequency Response Service (Continued)

18			
19			
20	**C. Depreciation Expense for Corps Generation**		
21			
22	Corps Generation Depreciation Expense	$10,650,544	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$421,473,130	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.527%	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.		

Fixed Charge Rate - Regulation and Frequency Response Service (Continued)

37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.507%	Cost of Capital Worksheet, C6L11
42			
43			
44	**G. Corps Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	9.938%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.527%	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	3.507%	L41
57			
58	Total	15.972%	

Rate for Energy Imbalance Service

Three deviation bandwidths – applied hourly to any energy imbalance as a result of Transmission Customer's scheduled transaction(s) -

1. **Deviations within ±1.5% (minimum 2 MW)** will be netted on a monthly basis and settled financially at the end of the month at 100% of the average incremental cost for the month.

Rate for Energy Imbalance Service (Continued)

2. **Deviations greater than ±1.5% up to 7.5% (greater than 2 MW up to 10 MW)** will be settled financially at the end of the month at:
   - 110% of incremental cost when energy taken in a schedule hour is greater than energy scheduled; and
   - 90% of incremental cost when energy taken in a schedule hour is less than the scheduled amount.

Rate for Energy Imbalance Service (Continued)

3. **Deviations greater than ±7.5% (or 10 MW)** will be settled financially at the end of the month at:
   - 125% of the incremental cost when energy taken in a schedule hour that is greater than energy scheduled; or
   - 75% of the incremental cost when energy taken is less than the scheduled amount.

Rate for Energy Imbalance Service (Continued)

Incremental Cost -

- Western's incremental cost will be based upon a representative hourly energy index or combination of indexes.

- Index(es) will be posted on OASIS prior to use.

- Will not be changed more often than once per year (unless Western determines existing index is no longer a reliable price index).

Rates for Operating Reserves Service – Spinning and Supplemental

- Operating Reserves Formula Rate

$$\textbf{Reserves Rate } \textit{per kW-Mo} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Rates for Operating Reserves Service – Spinning and Supplemental

Rate for Reserves for 2013

A.	Fixed Charge Rate	17.846%	(1)
B.	Generation Net Plant Costs	$ 473,919,619	(2)
C.	Annual Cost of Generation	$ 84,575,695	(A x B)
D.	Plant Capacity (kW)	2,420,000	
E.	Cost/kW ($/kW-Yr)	$ 34.95	(C / D)
F.	Monthly Charge ($/kW-mo)	$ 2.91	(E / 12 months)
G.	Western's Load (kW-Yr)	1,578,000	(3)
H.	Capacity used for Reserves (kW)	91,000	(4)
I.	Annual Reserves Revenue Requirement	$ 3,180,450	(E x H)
J.	Annual Charge ($/kW-Yr)	$ 2.02	(I /G)
K.	Monthly Charge ($/kW-mo)	$ 0.17	(J /12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2013 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 2011.

(4) Southwest Power Pool Reserve Sharing System.

Fixed Charge Rate - Operating Reserves Service – Spinning and Supplemental

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	$78,351,000	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$654,099,613	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	11.978%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$308,351	A&G Expenses Worksheet, C6L18
14			
15	Net Generation Plant Investment	$654,099,613	L6
16			
17	A&G as % of Net Generation Plant Investment	0.047%	L13/L15
18			
19			

Fixed Charge Rate - Operating Reserves Service – Spinning and Supplemental (Cont.)

20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	$15,137,195	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$654,099,613	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.314%	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			

Fixed Charge Rate - Operating Reserves Service – Spinning and Supplemental (Cont.)

Line	Description	Value	Reference
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.507%	Cost of Capital Worksheet, C6L11
42			
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	11.978%	L8
47			
48	A&G Expense	0.047%	L17
49			
50	Depreciation Expense	2.314%	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	3.507%	L41
57			
58	Total	17.846%	

Rate for Generator Imbalance Service

Three deviation bandwidths – applied hourly to any generator imbalance as a result of Transmission Customer's scheduled transaction(s).

1. **Deviations within ±1.5% (minimum 2 MW)** will be netted on a monthly basis and settled financially at the end of the month at 100% of the average incremental cost for the month.

Rate for Generator Imbalance Service (Continued)

2. **Deviations greater than ±1.5% up to 7.5% (greater than 2 MW up to 10 MW)** will be settled financially at the end of the month at:
   - 110% of incremental cost when energy delivered in a schedule hour is less than energy scheduled; and
   - 90% of incremental cost when energy delivered in a schedule hour is greater than the scheduled amount.

Rate for Generator Imbalance Service (Continued)

3. **Deviations greater than ±7.5% (or 10 MW)** will be settled financially at the end of the month at:
   - 125% when energy delivered in a schedule hour is less than energy scheduled; or
   - 75% when energy delivered is greater than the scheduled amount.

Exception: Intermittent resources will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.

Rate for Generator Imbalance Service (Continued)

Incremental Cost:

- Western's incremental cost - based upon representative hourly energy index or combination of indexes.
- Index(es) posted on OASIS prior to use.
- Will not be changed more often than once per year (unless Western determines existing index is no longer a reliable price index).

Rate for Generator Imbalance Service (Continued)

Western may charge a Transmission Customer for either *hourly generator imbalances* or *hourly energy imbalances for imbalances occurring within the same hour*, but not both, unless the imbalances aggravate rather than offset each other.

Transmission Service Penalty Rate for Unreserved Use

Penalty applies when:

- Firm reserved capacity is exceeded at any **Point of Receipt** or **Point of Delivery;** *or*
- There is use of Transmission Service at a **Point of Receipt** or **Point of Delivery** that is not reserved.
- In addition to payment for transmission service and penalty – customer is required to pay for all Ancillary Services in Open Access Transmission Tariff (OATT) *(provided by Western and associated with the unreserved use).*

Penalty Calculation

- 200% of Western’s approved transmission service rate for point-to-point transmission service assessed as follows:

  - The penalty for a single hour – based on the rate for daily Firm Point-to-Point Service.

  - The penalty for more than one assessment of a given duration – increases to next longest duration.

Penalty Calculation (Continue)

RATE

FREQUENCY

Frequency	Rate
Multiple hours in one day	• Daily Firm Point-to-Point Service rate
Multiple days in one week	• Weekly Firm Point-to-Point Service rate
Multiple weeks in one month	• Monthly Firm Point-to-Point Service rate

Contact Information

Materials will be posted on Website:
http://www.wapa.gov/ugp/rates/default.htm

Contacts:

Linda Cady-Hoffman, Rates Manager
Upper Great Plains Region
PO Box 35800
Billings, MT 59107-5800
Phone: 406-255-2920
E-mail: cady@wapa.gov

Lloyd Linke, Operations Manager
Upper Great Plans Region
PO Box 790
Watertown, SD 57201-0790
Phone: 605-882-7500
E-mail: lloyd@wapa.gov

Thank you for your attention. Please provide written comments or questions, via email or letter, by October 31, 2012.

Questions