FOLLOW UP QUESTIONS FROM THE

JANUARY 15, 2015 - PUBLIC INFORMATION FORUM

FOR THE PROPOSED RATE ACTION (WAPA-169),

SALT LAKE CITY AREA INTEGRATED PROJECTS FIRM POWER RATE AND

COLORADO RIVER STORAGE PROJECT TRANSMISSION AND ANCILLARY SERVICES RATES

1. **Unreserved Use Penalty:**
   a. Is Unreserved Use an Ancillary service? What is Unreserved Use?
      i. **Answer:** Unreserved Use is not an ancillary service, it is a penalty. Unreserved Use Penalties apply to any circumstance where a transmission customer uses transmission service that is not reserved or is in excess of reserved capacity. FERC order 890 adopted "Unreserved" to replace "Unauthorized" Use. FERC 18 CFR Parts 35 and 37 (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890)

   b. Is Unreserved Use charged to Load or Flow?
      i. **Answer:** Rather than charging to load or flow, it is based on the transmission capacity used above what was reserved.

   c. How much Unreserved Use penalty has been collected?
      i. **Answer:** CRSP has been historically charging Unauthorized Use at 150% of the transmission rate. The change to Unreserved Use Penalties at 200% is following FERC 890 pro forma. The table below shows the amount CRSP has collected for Unauthorized Use:

Historic CRSP Unauthorized Use (at 150%)

Year	Amount Collected
2009	$ 172,578.66
2010	$ 237,856.01
2011	$ 7,401.14
2012	$ 796.87
2013	$ 552.00
2014	$ 653.75
Grand Total:	**$ 419,838.43**

2. **Offsetting Revenues**
   a. Why have Spinning Reserves dropped?
      i. **Answer:** Spinning reserve sales from CRSP units have decreased over the past few years because of changing market conditions and to some extent operational constraints on CRSP generation resources. The industry Change from coal to gas and very low gas prices are making it economical to run gas fired generation so holding reserves elsewhere and only turning on gas for a reserve response is not as necessary for the large generators as it once was. Gas turbines are frequently being run for base load and they are holding reserves on those units as well. At Glen Canyon, because of flow constraints, we have placed a $2000 strike charge on our pricing structure for calling on reserves. This pricing structure has become less appealing to our customer pool. Environmental flows from the Aspinall Units have also limited the amount of reserves available for sale. Our 5-year rolling average shows the decreased revenues in our rate projections (see table below).

CRSP SPINNING RESERVES

YEAR	Amount	5-Year Rolling Average
2014	$ 2,788,974.00	$ 2,482,177.73
2013	$ 2,836,743.15	$ 3,081,472.72
2012	$ 2,631,129.33	$ 3,623,986.75
2011	$ 1,617,306.76	$ 4,097,071.05
2010	$ 2,536,735.42	$ 4,732,895.52
2009	$ 5,785,448.92	$ 5,074,653.04
2008	$ 5,549,313.32	$ 4,594,740.45
2007	$ 4,996,550.84	
2006	$ 4,796,429.10	
2005	$ 4,245,523.00	
2004	$ 3,385,886.00	

3. **Cost Recovery Charge (CRC)**
   a. Did the August 24 month study include the 9 million acre feet (MAF) release?
      i. **Answer:** Yes it did. The purchase power estimate for last August, based on the August 2014 24 month study releases, includes Glen Canyon releases of 9.0 MAF in FY2015, 8.68 MAF releases in FY2016, and 8.23 MAF releases after that.

   b. Can non-reimbursable costs trigger a CRC?
      i. **Answer:** Yes – Projected Annual Expenses is Western's estimate of expenses for the next FY, which includes all expenses plus non-reimbursable expenses – capped at $27 million/year plus an inflation factor.

4. **Other Expenses**
   a. Other expense increases – other than MOA Revenues, what is going up? Salinity?
      i. **Answer:** The total **Other** expenses increased by $12.5 million and from that increase: $11.5 million is from the MOA and $802 thousand (yearly average) is from the Salinity Control Program. The increases to the Basin-wide Salinity Control Program in FY2012 created the additional expenses.

   b. Have you considered the Intertie Contract post 2017?
      i. **Answer:** Western has not considered what actions will be taken at the end of this contract. Internal discussion will begin in the next few months. This proposed rate assumes the Intertie Contract will continue. The existing rate was used for projecting expenses.

5. **Non-Reimbursable costs**
   a. Have the 5-yr steady flow experiments been incorporated into the non-reimbursable cost calculation for 2008 to 2012? Why is 2011 zero?
      i. **Answer:** Yes, the 5-Year steady flow experiments are incorporated. In 2011, we established a lag year for booking non-reimbursable expenses since historic projections were unreliable. The lag year allows Argonne time to calculate non-reimbursable costs. We then include the non-reimbursable costs as actual expenses the year after they occur rather than submitting projections that will need a future true up adjustment.

   b. Is the non-reimbursable cap at $27M?
      i. **Answer:** Yes, Projected Annual Expenses (PAE) in the CRC calculations is Western's estimate of expenses for the next FY. The PAE includes all expenses plus non-reimbursable expenses which are capped at $27 million per year plus an inflation factor. **This limitation is for CRC formula calculation purposes only and is not a cap on actual non-reimbursable expenses. (This cap was set during the WAPA-137 rate action, FY2009).** The historic 5-year average (2009-2013) is $19.1 million per year.

6. **Transmission (Forward-Looking rate):**

   a. What are benefits to the proposed new transmission rate calculation?
      i. **Answer:** Western will better match cost incurrence with cost recovery.

b. The True-up – How is it done?

Narrative Transmission Calculation Example

The current process for computing the Colorado River Storage Project (CRSP) Point to Point Transmission Rate uses the actual audited financial data from the most recent historic year. The cumulative capital investment booked to plant is used to compute a fixed charge rate and this fixed charge rate is used to compute the Annual Transmission Revenue Requirement (ATRR).

The proposed Forward-Looking process will continue to use the audited financial data from the most recent historic year but will also include capital investment projections for the next year. At the end of the year, a True-up adjustment will be calculated.

Using **example figures** for FY 2016, the following steps provide an explanation of how the True-up process is included in the Point-to-Point Rate calculation:

STEP ONE: In July 2015 we will calculate the FY 2016 transmission rate using final audited historical financial data through FY 2014 and projected capital investments that will book to plant in FY 2015. This will provide a projected net investment. Using this projected net investment, a fixed charge rate will be calculated and the ATRR will be computed.

STEP TWO: Using this ATRR, the FY 2016 transmission rate will be calculated according to the formula contained in the CRSP Point-to-Point Transmission Rate Schedule (see attached Rate Schedule).

STEP THREE: In July 2016 we recalculate the FY 2016 transmission rate replacing only the projected capital investment with the actual capital investment booked in the FY 2015 audited financial statements. This will provide an actual net investment. Using this actual net investment, recalculate a new fixed charge rate and a new ATRR.

STEP FOUR: Compare the FY 2016 ATRR calculated in Step 1 with the ATRR calculated in Step 3. The difference (Projected – Actual) will be the True-up adjustment to be included in the FY 2017 transmission rate update.

STEP FIVE: In July 2016 we repeat Step 1 for FY 2017 (calculate the projected net investment, determine the fixed charge rate and compute the ATRR); carry forward the amount over/under collected from FY 2016 as the "Prior Year True-up Adjustment" and then Repeat Steps 2 through 5.

*FOR ILLUSTRATION PURPOSES

*FOR ILLUSTRATION PURPOSES

Western Area Power Administration
Colorado River Storage Project
FY16 Firm Point-to-Point Rate
Example

		FY 2016 Projected*		FY 2016 Actual*	Change	% change
Annual Cost for Transmission Service	1	**$ 63,546,628**	← ATRR →	3 **62,500,190**	$ (1,046,438)	-1.65%
Transmission Revenue Credits						
Non-FirmTransmission Revenue		$ (582,011)		$ (582,011)	$ -	0.00%
Ancillary Service Revenue		$ (407,161)		$ (407,161)	$ -	0.00%
Miscellaneous Revenue		$ (113,497)		$ (113,497)	$ 0	0.00%
Phase Shifter Revenue		$ (1,041,386)		$ (1,041,386)	$ (0)	0.00%
Provo River Project		$ (29,800)		$ (29,800)	$ -	0.00%
Exchange Contracts		$ (1,440,000)		$ (1,440,000)	$ -	0.00%
Total Transmission Rev Credits		**$ (3,613,855)**	← TRC →	**$ (3,613,855)**	$ (0)	0.00%
Annual Revenue Requirement:		**$ 59,932,773**		**$ 58,886,335**	**$ (1,046,438)**	-1.75%
Prior Year True-up Adjustment		**$ -**			4	
Adjusted Annual Revenue Requirement		**$ 59,932,773**	← NATRR →	**$ 58,886,335**		
Transmission System Load:						
Firm Power Obligations:						
Contract Rate of Delivery		1,435,886		1,435,886	0	
CRSP Merchant Reservation		1,992,000		1,992,000	0	
SRP Exchange		350,000		350,000	0	
Firm Wheeling Contracts		617,250		617,250	0	
Total		**4,395,136**	← TSTL	**4,395,136**	**0**	
Firm Point-to-Point Transmission Rate in $/kW:						
	2	**$ 13.64 kW-year**		**$ 13.40 kW-year**	$ (0.24)	-1.75%
		$ 1.14 kW-month		**$ 1.12 kW-month**	$ (0.02)	-1.75%
		$ 0.26 kW-week		**$ 0.26 kW-week**	$ (0.00)	-1.75%
		$ 0.04 kW-day		**$ 0.04 kW-day**	$ (0.00)	-1.75%
		0.00156 mills/kWh		**0.00153 mills/kWh**	(0.00)	-1.75%

*FOR ILLUSTRATION PURPOSES

Western Area Power Administration
Colorado River Storage Project
FY17 Firm Point-to-Point Rate
Example

	FY 2017 Projected*	
Annual Cost for Transmission Service	**$ 65,500,190**	
Transmission Revenue Credits		
Non-FirmTransmission Revenue	$ (582,011)	
Ancillary Service Revenue	$ (407,161)	
Miscellaneous Revenue	$ (113,497)	
Phase Shifter Revenue	$ (1,041,386)	
Provo River Project	$ (29,800)	
Exchange Contracts	$ (1,440,000)	
Total Transmission Rev Credits	**$ (3,613,855)**	
Annual Revenue Requirement:	**$ 61,886,335**	
Prior Year True-up Adjustment	**$ (1,046,438)**	5
Adjusted Annual Revenue Requirement	**$ 60,839,897**	
Transmission System Load:		
Firm Power Obligations:		
Contract Rate of Delivery	1,435,886	
CRSP Merchant Reservation	1,992,000	
SRP Exchange	350,000	
Firm Wheeling Contracts	617,250	
Total	**4,395,136**	
Firm Point-to-Point Transmission Rate in $/kW:		
	$ 13.84 kW-year	
	$ 1.15 kW-month	
	$ 0.27 kW-week	
	$ 0.04 kW-day	
	0.00158 mills/kWh	

*FOR ILLUSTRATION PURPOSES

Rate Schedule SP-PTP8
(Supersedes Schedule SP-PTP7)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To firm Point-to-Point transmission service Customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service:

Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Point-to-Point Rate Formula:

The firm Point-to-Point rate is based on projections on investments using an annual fixed charge methodology. The annual revenue requirement is reduced by revenue credits. The resultant net annual cost to be recovered is divided by the capacity reservation needed to meet firm power and transmission commitments in kW, including the total network integration loads at system peak, to derive a cost/kWyear. The cost/kWyear is calculated using the following formula:

1. ATRR - TRC = NATRR

2. $\frac{\text{NATRR}}{\text{TSTL}}$

Where:

ATRR = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expenses, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary service revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NATRR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

TSTL = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under the long-term reservation plus the total network integration loads at system peak.

This formula will be recalculated annually by applying the data from projections on investments and a true-up for any over collection or under collection from the previous FY. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective. The rate for transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS4, or any superseding rate schedule, for reactive supply and voltage control is attached as part of this Rate Schedule and applies to firm point-to-point transmission Customers.

Billing:

The point-to-point transmission Customer will be billed monthly by applying the resulting rate to the maximum amount of capacity reserved, payable whether used or not, except as otherwise provided in existing contracts.

Requirements for Reactive Power:

Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the Customer as established by contract. If losses are not fully provided by a transmission Customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission Customer, as appropriate.