CREDA
Colorado River Energy Distributors Association

ARIZONA
Arizona Municipal Power Users Association

Arizona Power Authority

Arizona Power Pooling Association

Irrigation and Electrical Districts Association

Navajo Tribal Utility Authority (also New Mexico, Utah)

Salt River Project

COLORADO
Colorado Springs Utilities

Intermountain Rural Electric Association

Platte River Power Authority

Tri-State Generation & Transmission Association, Inc. (also Nebraska, Wyoming, New Mexico)

Yampa Valley Electric Association, Inc.

NEVADA
Colorado River Commission of Nevada

Silver State Energy Association

NEW MEXICO
Farmington Electric Utility System

Los Alamos County

City of Truth or Consequences

UTAH
City of Provo

City of St. George

South Utah Valley Electric Service District

Utah Associated Municipal Power Systems

Utah Municipal Power Agency

WYOMING
Wyoming Municipal Power Agency

Leslie James
Executive Director
CREDA
10429 S. 51st St., Suite 230
Phoenix, Arizona 85044

Phone: 480-477-8646
Fax: 480-477-8647
Cellular: 602-469-4046
Email: creda@qwest.net
Website: www.creda.org

October 12, 2011

Ms. Cathy Castle
Mr. Darren Buck
Western Area Power Administration

Via email only: Cost_Allocation_Project@wapa.gov

Dear Ms. Castle and Mr. Buck:

CREDA offers the following initial comments on Western's proposed Cost Allocation Methodology as outlined in the September 29-20 customer meetings. We understand that Western is seeking comments by October 20; however, it would be most helpful if Western could provide responses to questions posed at the customer meetings in advance of any comment deadline so that those responses may be factored into customer comments.

Specifically, it would be helpful to have the data provided on slide 24 of the presentation materials presented historically. In addition, due to the unique nature of the Upper Colorado River Basin Fund, it is important the CRSP customers have a more complete understanding of the processes and potential outcomes associated with trust projects "coming and going" given the "pooling" type nature of the proposed Cost Allocation Methodology. Specifically, in response to a question at the September 29 meeting, the comment was made that "funding would have to come from other sources." What is the practical effect of a trust project "leaving", and a reduction in non-federal revenues? What are the "other sources"? Is our understanding correct that there would no longer be specific geographic "linkages" to individual federal projects and that if there is a shortfall in one region, all other regions would realize or share in that shortfall? Some clarification and additional detail would assist in our understanding.

Regarding the proposal to use nameplate rating as the generation allocator, we understand that it is a challenge to equate labor activities with physical assets in some cases, but would like Western to consider a different value as the generation-related allocator (as opposed to nameplate MVA. We suggest using the long-term maximum project seasonal commitment. For the SLCA/IP, that value would be SHP. It may be that in some of the projects this allocator may result in in the same value as would MVA, but as acknowledged in the customer meetings, the nameplate for Glen Canyon generation does not reflect actual use of the generation asset or Western's marketing thereof. This approach is consistent with the features of the proposed methodology: "fact-based, simple, easy to maintain, can work going forward".

We look forward to additional discussion as Western considers customer comments on this topic.

Sincerely,

/s/ Leslie James

Leslie James

Cc: CREDA Board
Tim Meeks
LaVerne Kyriss
Darrick Moe

Department of Energy
Western Area Power Administration
Desert Southwest Customer Service Region
P.O. Box 6457
Phoenix, AZ 85005-6457

Colorado River Energy Distributors Association
10429 S. 51ST ST, Suite 230
Phoenix, AZ 85044
Attn: Leslie James

Dear Ms. James:

In response to your letter dated October 12, 2011, we are providing the following responses to your questions identified in paragraphs 2 and 3 of your letter:

1) Specifically, it would be helpful to have the data provided on slide 24 of the presentation materials presented historically.

   RESPONSE: Generation and line miles over the past few years have changed very minimally and as such would have little to no impact on the percentages presented. Data was obtained from Western's 2010 Annual report and the Bureau of Reclamation's website. Please see the attached spreadsheet entitled "Cost Allocation – August 24-2011_1" for a more detailed explanation.

2) In addition, due to the unique nature of the Upper Colorado River Basin Fund, it is important the CRSP customers have a more complete understanding of the processes and potential outcomes associated with trust projects "coming and going" given the "pooling" type nature of the proposed Cost Allocation Methodology. Specifically, in response to a question at the September 29 meeting, the comment was made that "funding would have to come from other sources."

   a. What is the practical effect of a trust project "leaving", and a reduction in non-federal revenues?

   RESPONSE: There are 5 trust projects which Western receives compensation for performing work associated with those trust projects. The trust projects and their associated cost responsibility for Operation's costs are:

   1 - Mead Phoenix Project (MPP) – 2.92%
   2 – Independent Power Producers (IPP) – 3.3%
   3 – Laramie River Station (LRS) – 2.25%
   4 – Rapid City DC Tie (RDC) – 0.47%
   5 – Dry Fork (DF) – 1.96%

   This trust work provides adequate revenue to cover 10.93% of Western's Operations Division labor costs. The remaining 89.07% cost responsibility is divided among the 9 Federal Projects as was presented at the meeting and based on the following percentages:

1 – Pick-Sloan (PS) – 25.89%
2 – Fryingpan Arkansas (FA) – 1.47%
3 – Colorado River Storage (CR) – 26.94%
4 – Central Arizona (CA) – 5.68%
5 – Boulder Canyon (BC) – 9.09%
6 – Parker-Davis (PD) – 17.95%
7 – Intertie (IN) – 1.65%
8 – Front & Levee (CL) – 0.13%
9 – Salinity Control (CS) – 0.26%

Should Western lose any of the trust projects listed above, the costs will be allocated among the 9 Federal Projects and their percentage cost responsibility will increase. For instance, if the IPP terminates its contract with Western, Western would need to reallocate an additional 3.3% to the other Federal Projects, and if new trust revenue comes in, all projects will benefit and a reduction to the percentage cost will result in the 9 Federal Projects.

b. What are the "other sources"?

RESPONSE: The "other sources" are the Federal power systems in the cost allocation pool, which are listed under (a) above.

c. Is our understanding correct that there would no longer be specific geographic "linkages" to individual federal projects and that if there is a shortfall in one region, all other regions would realize or share in that shortfall?

RESPONSE: Correct. The Operation's organization staff are located in two control centers (Loveland and Phoenix), and cost are allocated based on the functional tasks performed without any regards to which office performs the work or which BA does the work. The total operations' cost is integrated from all Federal Projects within the DSW, RMR, and CRSP footprint. Post OCP, Western Operates across this entire footprint with one integrated operations function. The efficiencies gained from this integration benefit all customers within this geographic area.

3) Regarding the proposal to use nameplate rating as the generation allocator, we understand that it is a challenge to equate labor activities with physical assets in some cases, but would like Western to consider a different value as the generation-related allocator (as opposed to nameplate MVA). We suggest

using the long-term maximum project seasonal commitment. For the SLCA/IP, that value would be SHP. It may be that in some of the projects this allocator may result in the same value as would MVA, but as acknowledged in the customer meetings, the nameplate for Glen Canyon generation does not reflect actual use of the generation asset or Western's marketing thereof. This approach is consistent with the features of the proposed methodology: "fact-based, simple, easy to maintain, can work going forward".

RESPONSE: Western did consider the option to use SHP but it was concluded that the drought over the last five years has had a comparable impact on all project generation levels so the overall percentage amongst the projects wouldn't change substantially. In addition, SHP is a minimum and can be exceeded when there is sufficient water. In order to keep the data gathering for future years as simple as possible, using the nameplate generation capability was more desirable instead of gathering actual generation level for each project; which can be different seasonally, thus, rendering a more variable and possibly more drastic percentage cost responsibility.

In response to your comment regarding the actual use of the generation asset (Glen Canyon) is minimized by environmental legislation, this can be said as well for Yellow Tail, which is also restricted by environmental constraints. In addition, Hoover's actual use is not only minimized by legislation but is also limited to the contingent allocation itself, which is significantly lower than the actual nameplate. We agree that all power systems have their own nuances and that is why we believe the selected cost allocation methodology provides consistency within each generation asset.

Please contact either Darren Buck, RMR Operations Manager at 970-461-7693 or myself at 602-605-2404 if you have any further questions or comments. Thank you in advance for your assistance in this matter.

Sincerely,

Catherine M. Castle

Catherine M. Castle
Cost Allocation Project Manager

Attachment

cc: G0000, Darrick Moe
G6000, Debby Emler
J4000, Darren Buck