MAXIMIZING POWER GENERATION AT FEDERAL FACILITIES

OVERSIGHT HEARING

BEFORE THE

SUBCOMMITTEE ON WATER AND POWER

OF THE

COMMITTEE ON RESOURCES
U.S. HOUSE OF REPRESENTATIVES

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MAXIMIZING POWER GENERATION AT FEDERAL FACILITIES

Thursday, April 26, 2001
U.S. House of Representatives
Subcommittee on Water and Power
Committee on Resources
Washington, DC

The Subcommittee met, pursuant to call, at 2 p.m., in Room 1324, Longworth House Office Building, Hon. Ken Calvert [Chairman of the Subcommittee] presiding.

STATEMENT OF THE HONORABLE KEN CALVERT, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. CALVERT. The oversight hearing by the Subcommittee on Water and Power will come to order. The Subcommittee is meeting today to hear testimony on maximizing power generation at Federal facilities. We will be joined shortly by the Ranking Member Adam Smith, but in the interest of time, we are going to move this hearing along. Under committee rule 4(g), the Chairman and the Ranking Minority Member can make opening statements. If any other Members have statements, they can be included in the hearing and the record under unanimous consent.

Over the last century, electricity consumers have invested hundreds of millions of dollars in Federal hydroelectric facilities. They have invested in good faith that those facilities would be maintained and that they would provide electricity when needed. However, the generating capacity at many of these facilities have been eroded over time. During the past 6 years our Subcommittee has asked the General Accounting Office to examine ways that we can improve the operation of the Federal hydropower projects.

While we have made progress, the Bureau of Reclamation is still faced with a $5 billion backlog. Generation at other projects has been strained due to regulatory restrictions. Glen Canyon Dam has lost one-third of its peaking capacity, and electricity generation has decreased 13 percent since 1980 at the Central Valley Project because of environmental regulations. Electricity bills are rising as utility companies are forced to replace this lost power by going into the market and competing for scarce supplies. These costs will only increase as hot summer weather escalates demand and drought decreases supply of both power and water.

Keeping the lights on this summer and in the future means that we must be careful to maximize the use of our limited resource. We cannot continue to talk about managing our water resources or power resources as two separate areas. But it is easy to see the direct link between water and power at hydroelectric dams. What is often overlooked is the fact that conventional generation also uses a large amount of water. Responsible planning for the future means ensuring adequate and reliable supplies of both resources.

This hearing is another step in looking at how Federal water and power resources can be better managed to create stable supplies and meet future demand. It is good sense and good policy to maximize benefits from existing facilities to meet the needs of both power and water users.

[The prepared statement of Mr. Calvert follows:]

Statement of The Honorable Ken Calvert, Chairman, Subcommittee on Water and Power

Over the last century electricity consumers have invested hundreds of millions of dollars in federal hydropower facilities. They have invested in good faith that these facilities would be maintained and that they would provide electricity when needed.

However, the generating capacity in many of these facilities has been eroded over time. During the past 6 years, our Subcommittee has asked the General Accounting Office to examine ways we can improve the operation of federal hydropower projects. While we have made progress, the Bureau of Reclamation is still faced with a $5 billion dollar backlog.

Generation at other projects has been constrained due to regulatory restrictions. Glen Canyon Dam has lost one-third of its peaking capacity and electricity generation has decreased 13 percent since 1980 at the Central Valley Project because of environmental regulations.

Electricity bills are rising as utility companies are forced to replace this lost power by going into the market and competing for scarce supplies. These costs will only increase as hot summer weather escalates demand, and drought decreases the supply of both power and water.

Keeping the lights on this summer, and in the future, means that we must plan carefully to maximize the use of our limited resources. We cannot continue to talk about managing our water resources, or our power resources, as two separate areas. While it is easy to see the direct link between water and power at hydroelectric dams, what is often overlooked is the fact that conventional generation also uses a large amount of water. Responsible planning for the future means ensuring adequate and reliable supplies of both resources.

This hearing is another step in looking at how federal water and power resources can be better managed to create stable supplies and meet future demand. It's good sense and good policy to maximize benefits from existing facilities to meet the needs of both power and water users.

I'd like to thank our witnesses and look forward to hearing from them at this time.

[The prepared statement of Mr. Shadegg follows:]

Statement of The Honorable John Shadegg, a Representative in Congress from the State of Arizona

Mr. Chairman, thank you for the opportunity to take part in today's hearing. I ask that three newspaper articles be made part of the record.

On March 21, 2001, Knight Ridder reported on blackouts in California the day before which lasted four and a half hours before sufficient power was available to lift the blackout. The paper reports "Grid officials credited an influx of 300 megawatts from the Glen Canyon hydroelectric plant" for ending the blackout.

On December 9, 2000, the Washington Post reported that the "California power grid is on verge of collapse" and stated that two days earlier "The grid was also saved by a last-minute surge of juice from the Western Area Power Administration, which sent electricity over its lines from its facility at the Glen Canyon Dam."

Finally, on September 25, 2000, the Dow Jones Energy Service ran a story under the headline "U.S. Dam Rescues California Grid" and wrote "California averted a blackout last week with some help from the federal government. The U.S. Bureau of Reclamation opened the floodgates at the massive Glen Canyon dam in Arizona providing 300 megawatts of power."

The article also points out that "Under a mandate from the Interior Department to restore riverbank beaches ... Glen Canyon has been operated for the last few years in a way that reduces net power production from the dam by about 900 megawatts."

We have three examples in less than a year of how vital Glen Canyon Dam, and the peaking power it provides, are to the safety of the Western electricity grid and thus to the well-being and lives of the people who depend on that grid. Yet there are some individuals who want to tear down the dam and thus deprive people of this power, as well as the water which the dam stores as insurance against a long term drought.

The current electricity crisis stems from a lack of generation capacity, a fact attested to by numerous power experts including the three Commissioners of the Federal Energy Regulatory Commission. This crisis is exacerbated by operating restrictions imposed by the 1996 Record of Decision which prevent Glen Canyon Dam from producing at full capacity unless blackouts are imminent.

Glen Canyon Dam is a major generating asset which, if used efficiently, could provide significantly more power to Arizona and other basin states, and thus make more power available to address shortages throughout the West. By preventing it from being used in this way, the operating restrictions imposed by the 1996 Record of Decision are implementing a decision that beaches along the Colorado River are more important than the well-being of people.

Mr. CALVERT. I would like to thank our witnesses for coming out here today and look forward to hearing from them. When Mr. Smith arrives, we will give him time for his opening statement. In the meantime, we will go ahead and introduce our first panel, which is Mr. J. William McDonald, the Acting Commissioner, Bureau of Reclamation, and he is accompanied by Mr. Mike Hacskaylo, Administrator of the Western Area Power Administration; and Mr. Jeff Stier, Vice President for National Relations, Bonneville Power Administration.

And with that, Mr. Bonneville—or excuse me, Mr. Bonneville, yeah, I will get that—if there is such a person, please raise your hand. I will now recognize Mr. McDonald to testify for 5 minutes. You have some timing lights there. We would appreciate that you would attempt to stay within that 5 minutes so that we have plenty of time to ask some questions.

With that, will Mr. McDonald please begin your testimony?

STATEMENT OF J. WILLIAM McDONALD, ACTING COMMISSIONER, BUREAU OF RECLAMATION, ACCOMPANIED BY MIKE HACSKALOW, ADMINISTRATOR OF WESTERN AREA POWER ADMINISTRATION; AND JEFF STIER, VICE PRESIDENT FOR NATIONAL RELATIONS, BONNEVILLE POWER ADMINISTRATION

Mr. MCDONALD. Thank you, Mr. Chairman. I have a written statement, and I will simply summarize that, if I may, please.

The Bureau of Reclamation, as you well know, is the second largest hydropower utility in the United States with 194 generating units located in 58 power plants throughout the Western States. We have an installed capacity of about 14,700 megawatts, which produce power for our project use and our customers. We are the mainstay, in many ways for ensuring the reliability of the Western Interconnected System.

There are several general conditions under which our power plants and out power system operates. I would like to touch on those by way of a general summary. First, water is the fuel of the hydropower system, and while it has the advantage of being an annually renewable fuel, it is finite, and it varies substantially from year to year.

Secondly, even if water is in storage in one of our project reservoirs, the annual amount of water available for release is always governed by a variety of laws, and generally speaking those would be international treaties, interstate compacts and judicial decrees apportioning interstate streams, and then a variety of Federal project-authorizing statutes which govern project operations.

Thirdly, the scheduling on a daily and a weekly basis of water is governed by water user demands, water supply being the primary authorized project purpose in all cases, and hydropower production at our projects being a secondary congressionally authorized project purpose.

Fourthly, power generated by our facilities is used first for project purposes, for example, project pumping to lift irrigation supplies to our irrigators. On an agency-wide average annual basis, we use about 5 to 7 percent of the energy which is generated every year. The balance, which we refer to as surplus power, is marketed by the Western Area Power Administration or the Bonneville Power Administration. They do all marketing, all contracting and make the necessary purchases of replacement power. How and to whom power is marketed is done in accordance with Federal law, and to make very complex storage simple, in general that marketing is to so-called preference customers.

And finally, let me emphasize that throughout Reclamation, all firm power via Western and Bonneville, is under contract.

Sixthly, it is important to understand that there are some significant transmission constraints in the Western grid system. Those are schematically shown on a map attached to my statement. I would just emphasize that even if Reclamation can generate it, we cannot necessarily get it to the right place.

And finally, there are contemporary environmental and tribal trust asset considerations that affect project operations. They particularly relate to downstream riverine environments and aquatic species, and particularly reflect themselves relative to the use of our plants for peaking purposes; that is to say they can affect energy, although typically not capacity.

About 85 percent of our total capacity is concentrated in four systems. Let me just touch very briefly on those, particularly related to the California power situation. The Central Valley Project in California consists of six power plants. About 75 percent of the energy generated by that system is surplus to project needs. All of that is under contract by Western to users in California. This year, our forecasted runoff in the Central Valley is only about 60 percent of average. As a consequence, power generation, coupled runoff with reservoir releases, will only be about 80 percent of average this summer.

We are doing three main things with the Central Valley Project to try to help the California situation. First, all maintenance that we would—would routinely do in the winter will be completed by

June 1st. Secondly, we are shifting project pumping to off-peak hours as much as we can. And thirdly, we are doing everything we can to optimize and schedule releases for peak demand periods within the limits of delivery in our water supply.

The second major system are the dams on the lower Colorado River, Hoover, Parker and Davis, which straddle the Colorado River on the California/Arizona border. Annual releases there are governed by the complex body of laws known as the Law of the Colorado River, which includes a treaty, compact, U.S. Supreme Court decrees, statutes and contracts.

I think what I would emphasize here is two things. All power marketed from the lower Colorado River is, by statute, provided 50 percent to California entities. All of that is under contract, and we are able to respond on the lower Colorado River to Stage 3 emergencies declared by California through the California ISO, and, in fact, have done that on all occasions that occurred this winter.

The third major piece of the system is the Federal Columbia River Power System. The thing to emphasize there, by way of conclusion, is that that is a system that typically is able to sell power to California in the summer when California has summer peaks. In turn, historically California has sold power to the Pacific Northwest in the winter when the Pacific Northwest has its peaks.

The Columbia River system faces a near record drought this year, or perhaps a record drought. Under those circumstances, we will have to run the Federal Columbia River Power System generating all power for the use of the Bonneville Power Administration and its customers and in general would not expect this summer to be able to sell power from the Pacific Northwest to California.

I would just conclude by observing, Mr. Chairman, that over the years, particularly in the past 15 to 20 years, we have been able to uprate and rewind turbines at many of our facilities such that we have added about 1,800 megawatts. The future would hold the opportunity for about another 500 megawatts, by doing additional uprates, rewinds and turbine runner replacements so there is still the opportunity for some capacity in the system.

With that, I will conclude my remarks and be glad to respond to questions.

Mr. CALVERT. Mr. McDonald, I thank you for your testimony.

[The prepared statement of Mr. McDonald follows:]

Statement of J. William McDonald, Acting Commissioner, Bureau of Reclamation, U.S. Department of the Interior

I am Bill McDonald, Regional Director for the Bureau of Reclamation's (Reclamation) Pacific Northwest Region located in Boise, Idaho, and am currently serving as Acting Commissioner. I appreciate the opportunity to discuss Reclamation's role in regulating the flow of water on key rivers and the impact on output of hydroelectric plants that are operated by Reclamation.

Before I discuss Reclamation's current activities as they relate to the generation of hydroelectric power, I would like to give the Subcommittee some background on Reclamation's hydroelectric power activities. This should provide important context as we discuss the current situation and Reclamation's role and activities.

Background

The Bureau of Reclamation is the nation's second largest producer of hydroelectric power. It ranks as the 10th largest power producer in the United States with 58 hydroelectric powerplants, 194 generating units in operation and an installed capacity of 14,744 megawatts (MW). In addition, Reclamation has a 547 MW share of the installed capacity of the coal-fired Navajo Steam Powerplant. The power produced at such projects that is available for commercial sale is marketed by the Western Area Power Administration (Western) and the Bonneville Power Administration (Bonneville).

Reclamation powerplants annually generate about 49 billion kilowatt hours (kWh) of hydroelectric energy—enough to meet the annual residential needs of over 14 million people or the electrical energy equivalent of over 80 million barrels of crude oil. Currently Reclamation's Central Valley Project accounts for about 4 percent of California's installed capacity in state. Westwide, Reclamation helps to maintain the stability and reliability of the overall power grid through the Western Systems Coordinating Council (WSCC) - a voluntary system reliability organization in which Reclamation, the California utilities and 13 other western states participate.

Over the past 25 years, Reclamation has done a great deal to increase the generation capacity of its hydroelectric facilities throughout the west. In 1976, Reclamation had 50 powerplants with a total capacity of 9,111 MW. Today, Reclamation's 58 powerplants have an installed capacity of 14,744 MW for a 62 percent increase. It is important to note that Reclamation's aggressive uprating and rewind program at existing power plants accounts for more than 1,783 MW of that increase, which represents 12 percent of Reclamation's total generation capacity.

Legal and Operational Issues: While Reclamation's installed nameplate capacity is significant, there are a number of legal and operational factors that limit energy generation.

1) Power is Secondary Purpose: Reclamation's hydroelectric power facilities are part of specifically authorized multipurpose water projects which provide benefits such as irrigation, municipal and industrial water supply, flood control, fish and wildlife protection and recreation. Power is, by statute for most projects, a secondary project function to delivery of irrigation and municipal and industrial water supplies. This means that water deliveries, pursuant to contracts, take precedence over electric power generation. Further, many projects are required to schedule water deliveries in accordance with interstate apportionment decrees and compacts and with international treaties. Therefore, water may not be available to generate power, as it may be committed to a primary project function such as flood control, or agricultural or municipal and industrial deliveries. In some cases, Reclamation may be required to release more water from its reservoirs than can be accommodated using only the power plant turbines.

2) Only Surplus Power is Marketed: Under Reclamation law, the first priority for the use of power generated by Reclamation's projects is to meet the needs of that project. This includes power for pumping water for delivery to our water users. On a Reclamation-wide basis, about 5 to 7 percent of the power we generate each year is used for project purposes. Within parts of the Central Valley Project (CVP) in California, however, there are times of the year—particularly during the irrigation season—when our generation does not even produce enough power to meet the project's pumping needs. In response, Western must buy power to serve irrigation needs on the spot market just like any other power user.

When there is power surplus to a project's needs, it is provided to Western or to Bonneville in the Pacific Northwest. Reclamation manages only the generation of power at its facilities. These Federal agencies in turn market this power to customers who are primarily preference customers, such as municipal utilities, as required by statute. Portions of the revenues derived from such sales are used to repay their investment costs that are the responsibility of the irrigators but exceed their ability to repay.

3) Power is Already Committed by Contract: As the marketers for Reclamation's power, Bonneville and Western have entered into contracts with preference customers for all of the anticipated available generation. The only time that additional power may be available to non-contracted entities is when there is excess water in the system that can produce more power than is already obligated or expected. All power generated at Hoover Dam is committed even when there is excess water in the system. In a dry year, however, Western and Bonneville have to buy power from other sources to make up the difference in their existing contracts. In today's spot markets, those costs have increased as much as ten fold over the last year. In a normal or dry year, there is little or no power produced that is not already under contract through Western or Bonneville.

4) Transmission System Constraints: Map 1 attached to my testimony, shows a multitude of power facilities - albeit small ones - on the east side of the Continental divide. These facilities currently serve customers in the regions in which they are located. Map 2 shows that the Federal transmission system is not designed to move power from these units long distance to California. Also, within California, the capacity to move electricity, particularly from the south to the north, is limited. Thus, although Reclamation through Western, delivers power from Hoover, Parker and

Davis Dams on the Lower Colorado River to Los Angeles and Southern California, there is at times insufficient transmission capacity to get that power to northern California - where much of the recent need has been.

There is also no Federal transmission line to get electricity from Glen Canyon Dam, on the Colorado River, to either southern or northern California. Power from Glen Canyon Dam can be sent to Arizona, but there is usually insufficient transmission capacity to get electricity through Arizona to California. To do so would displace other power that is also intended for California, unless Western is able to exchange power with some other entity.

5) Hydrologic Conditions: Water is the fuel for a hydropower system. While water is an annually renewable fuel, its availability varies considerably from year to year.

In California, water supply forecast is now about 40 percent below normal. As a result, Reclamation's hydro generation is below average. Reclamation's CVP power facilities, in an average summer, generates 5,000 gigawatt hours(GWh). This summer, however, due to low river and reservoir levels, CVP facilities are expected to generated only about 4,100 GWh—which is 18% below average.

In the Pacific Northwest, the runoff forecast is for a near record drought. While the average annual flow of the Columbia River at the Dalles is about 106 million acre feet, flows this year will be only half that amount.

6) California/Northwest Exchange: Historically, the Pacific Northwest and California have exchanged power during their respective high demand seasons—winter in the Pacific Northwest and summer in California. In the summer, when the Northwest's demand is lower, the Pacific Northwest exports power to California—during its high demand season. Then, in winter, when California's demand is—on average—lower, California exports power to the northwest - where the winter months are colder and demand is higher. This relationship has served both regions well.

Unfortunately, it is not working that way this year. As we saw this past winter, California was not able to export power to the north, as they were not able to meet their own winter needs. In fact, California found itself in need of imported power (at a time when they usually export it). This meant that Bonneville, which usually depends upon California's imports, did not have imported power available to meet its customers' load. In response, Bonneville needed to increase the output of the facilities of the Federal Columbia River Power System (FCRPS), as well as buy power on the spot market. It also meant that there was significant draw down of the reservoirs in the FCRPS. This year, with the dry weather, there is little prospect that these reservoirs will be able to refill this summer. To California, this means that the Pacific Northwest may not be able to export power during the upcoming summer months. Bonneville will continue to exchange energy whenever possible to help California with peaking problems while providing the Northwest with much needed energy.

7) Environmental and Trustee Considerations: Reclamation must also operate its projects consistent with environmental laws, such as the Endangered Species Act, and with Indian trust property responsibilities and Indian fishing rights. In any hydropower system there can be significant fluctuations in flow that may have impacts on the environment and recreation. Since most Reclamation hydropower facilities are located on rivers inhabited by threatened and endangered fish species, operations are constrained to ensure that these fish and their habitat are not jeopardized by adverse flow schedules or pulsed flows. We are coordinating with National Marine Fisheries Service and the U.S. Fish and Wildlife Service to identify opportunities to provide additional assistance for power generation that will not adversely affect these fishery resources.

System Reliability: Mr. Chairman, one of the significant benefits of hydropower, in general, and Reclamation's system, in particular, is the flexibility it affords. Hydro generation can be ramped up or down very quickly to respond to changes in demand and to the needs of the regional transmission system to remain stable. (A caveat here is that rapid changes may have detrimental fish and wildlife impacts.) Because of the size of Reclamation's system, along with its capacity and the large number and diversity of units available, Reclamation serves as a mainstay for ensuring the reliability of the Western Interconnected System. In the event of a WSCC system emergency, Reclamation hydro power can be brought on-line quickly to meet system emergency demands. Reclamation hydro power also provides voltage control, load following, spinning reserves, and black start capability" all of which provide critical, much-needed stability to the western power grid.

Current Activities in Response to Power Crisis: Reclamation works closely with Bonneville, Western, the WSCC and the California Independent System Operator (ISO) to provide whatever assistance it can to California.

1) Adjustments to Increase “Peaking Power”: Reclamation continues to work on flexible power generation schedules to support the needs of the western power grid. Western and Bonneville, on behalf of the California ISO, routinely ask Reclamation to rearrange its power generation schedule to help with the morning and afternoon peaks. In many cases, Reclamation has asked its project pumping customers to shift the timing of their deliveries to off-peak times to make more peaking power available to the market. At Grand Coulee Dam in eastern Washington, we have been able to shift more than 300 megawatts of pumping load to off peak times—making it available to Bonneville for peaking purposes. This summer in the CVP, Reclamation anticipates that significant project pumping loads can be shifted to off-peaking, making that power available to Western to help meet the demand for peaking power in California.

2) Conservation: Reclamation continues to maximize power production and minimize consumption to reduce projects needs and make power available. We have also facilitated the purchase of water that would otherwise need to be pumped or diverted upstream of the generators. This makes both more water available for generation and makes some “project use power” available to the market.

3) Maintenance Schedules: In California, Reclamation has complied with the “No Touch Day” requirement and “Warning” market notices. These notices have been in effect for all 105 days of 2001. Generator maintenance or maintenance of communications or protective systems is not be performed if a “No Touch Day” is in effect. Over the past year, Reclamation has worked very closely with Bonneville and Western to coordinate scheduled maintenance activities to maximize the number of facilities on line to respond to the energy needs of the western United States. In many instances scheduled maintenance that requires outages, has been delayed or rescheduled to accommodate system needs. Where maintenance cannot be delayed, Reclamation has resorted to double shifting at some facilities, and a greater use of overtime, to shorten the time that facilities will be out of service.

4) Responses to Stage 3 Emergencies: While Reclamation’s ability to generate power sometimes is limited by the factors identified above, we have been able to respond to requests from Western and Bonneville on behalf of the California ISO during many of the recent emergencies to provide additional power to California. Within the CVP, for example, Reclamation placed all its CVP generating units into production for the duration of the emergency. In the Pacific Northwest, Reclamation, in consultation with Bonneville, reshaped the water releases to assist California during Stage 3 events. In addition, the following chart indicates the specific increases from Hoover and Glen Canyon dams as of April 19, 2001.

Future Activities and Opportunities: As stated above, Reclamation has over the past 25 years undertaken an aggressive uprating and efficiency improvement program, which has significantly expanded the capacity of our hydropower system. While most of the significant benefits have already been realized, Reclamation has identified and will continue to explore additional opportunities to further expand our capacity and efficiency.

1) Increase Efficiency and Reliability: In partnership with Bonneville, Western and some of our power customers, Reclamation is working to replace the turbine runner blades in some of our facilities. The on-going runner replacement work at Grand Coulee, for example, can increase the efficiency of the facility and will result in 45–50 MW of additional energy at the facility. Reclamation is exploring the feasibility of other investments such as a similar effort at Shasta Dam in California which could result in an additional 51 MW of power. We estimate that by doing this at other Reclamation facilities, Reclamation could realize an additional gain of as much as 350 MW over the next 5 to 10 years.

2) Additional Uprates and Rewinds: While most of the significant increases in capacity have already been realized by our long standing uprating and rewind efforts, we can see that over the next 5 to 10 years, an additional 200 MW gain is possible across all of Reclamation’s power system.

3) Increased Focus on Power Facility Reliability - Reclamation hydropower plants are an average of 44 years old. Given this aging infrastructure, Reclamation is placing an increasing emphasis on the reliability of our plants in our operation and maintenance activities. Additionally, we are exploring the possibility of Reliability Centered Maintenance and Life Extensions in order to assure continued reliability of our plants.

Conclusion

In summary, Mr. Chairman, Reclamation’s hydropower projects play a significant role in addressing California’s power needs - both in terms of supply and in terms of maintaining the stability of the system. In the summer of 2000, and so far in

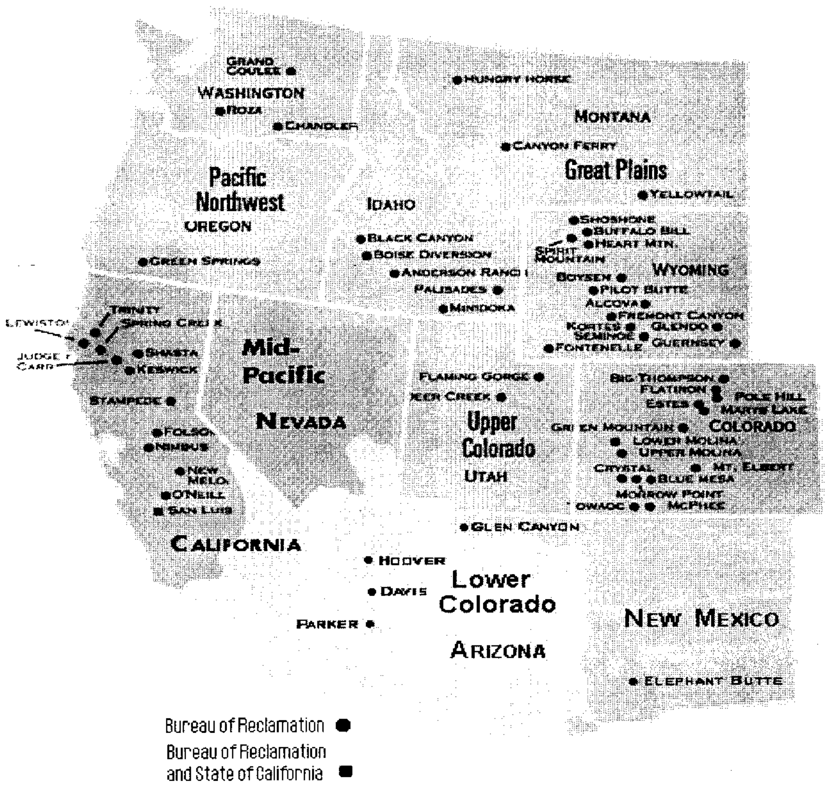
2001, the below normal water supplies have limited and will continue to limit our ability to generate hydropower.

This concludes my testimony. I would be glad to answer any questions.

[Attachments included in Mr. McDonald's testimony follow:]

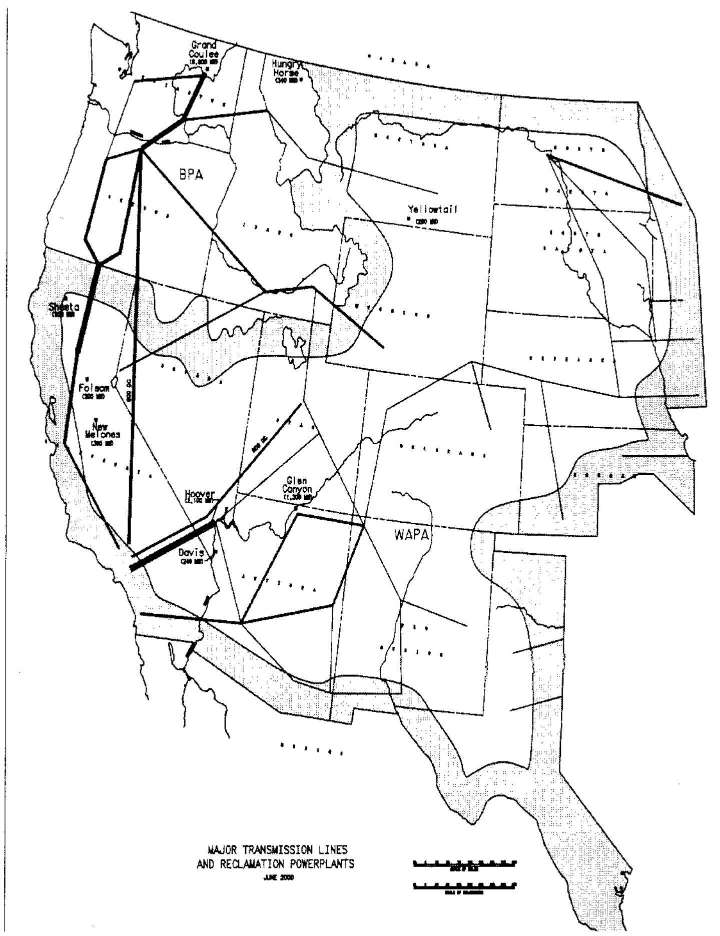
Facility	Date	Emergency Stage	Length of Time	Generation Increase
Hoover Dam	12/7/2000	Stage 3	2 hours	800 to 1,500 MW
Hoover Dam	1/11/2001	Stage 3	15 hours	300 to 1,200 MW
Hoover Dam	1/12/2001	Stage 3	3 hours	300 to 500 MW
Hoover Dam	1/16 - 2/16	Stage 3		Initiated double Peaking schedule
Glen Canyon Dam	9/18/2000	Stage 3	4 hours	523 to 655 MW
Glen Canyon	2/15/2001	Stage 3	5 hours	496 to 784 MW
Glen Canyon	3/19/2001	Stage 3	10 hours	420 to 791 MW
Glen Canyon	3/20/2001	Stage 3	5 hours	575 to 826 MW

Map 1
Reclamation Power Facilities



Reclamation's Power Facilities

Map 2
Transmission System Constraints



Mr. CALVERT. We have a vote on the floor, followed by one additional vote, so we will recess and then immediately reconvene, and Mr. Cannon at that point has an opening statement he would like to make.

Mr. Flake?

Mr. FLAKE. If I am unable, Mr. Chairman, to return, may I ask without objection that my statement be entered as part of the record?

Mr. CALVERT. Without objection, your opening statement will be entered into the record.

[The prepared statement of Mr. Flake follows:]

Statement of The Honorable Jeff Flake, a Representative in Congress from the State of Arizona

Water projects such as the Colorado River Storage Project serve multiple purposes with the benefits going out to a wide range of people. While water delivery is first and foremost among these benefits, power generation has become an equally important purpose with other factors such as recreation and environment following as ancillary benefits. Much more so than Eastern states, the West is strongly dependent upon the valuable resources of their water supplies. I am a strong supporter of preserving the environment under sound management plans.

Glen Canyon Dam, largest of the Colorado River Storage Projects consists of eight generators for a total of about 1300 megawatts equaling more than 70% of total generation of the CRSP.

Glen Canyon's generating capability has been considerably impacted over a period of time through various laws and regulations that have served to stifle the output of the operation. A 1996 Environmental Impact Statement (EIS) statement subsequently reduced the flow of the operation and resulted in a 1/3 generating capacity loss for the project. The complete effect on the environment is speculative. An April 2000 low flow experiment once again impacted the generating capability of the project. The alleged benefit of that experiment is also speculative.

These conditions have forced CRSP customers and WAPA to purchase replacement power elsewhere at additional cost. While Glen Canyon Dam currently experiences this 1/3 reduction in output, the project's emergency release program has been invoked on three occasions since September of 2000 to prevent a grid outage.

Recommendations on flows of federal hydropower operations must be based on sound science and accurately reflect true economic impacts. Returning these dams to prior production capacity would not only decrease the burden of current energy demands but would provide a clean source of power.

Mr. CALVERT. We will recess for 15 minutes, 20 minutes and reconvene.

[Recess.]

Mr. CALVERT. Mr. Cannon will be here shortly, but we will go ahead and begin testimony and allow Mr. Cannon to begin his opening statement.

Mr. McDonald, has Reclamation been able to adequately keep up on repairs and maintenance during the energy crisis so that there will not be the systemwide outages later on? You mentioned in your testimony you felt that you would have everything adequately done by June 1st. Is that pretty much the case, or do you think that there are other problems that may have to be dealt with this summer?

Mr. MCDONALD. Yes. We have no particular concerns. A lot of plants are down in the winter because water deliveries are relatively low. So it is typical for us to do our routine maintenance in the winter, but even as we had plants down this winter for scheduled maintenance, there is not an instance of which I am aware that we didn't have sufficient capacity, given the water available, to generate all power that could be generated. And as we hit peak summer demands, and we will run more water through the generators this summer, we will have everything back online.

Mr. CALVERT. How much generating capacity is lost at the reclamation facility due to the environmental regulations? Do you have any number on that how many megawatts is lost?

Mr. MCDONALD. On a West-wide basis it, varies from project to project where we have confronted situations like that, but clearly the principle issue has been at the Glen Canyon Dam where there has been about a 30 to 33 percent loss in capacity relative to historic operations, pursuant to the requirements of the Glen Canyon Protection Act.

Mr. CALVERT. And how much—what is that peak power, and how do we define that in megawatts of peak power, 35 percent?

Mr. MCDONALD. Well, the installed capacity at Glen Canyon is—a couple of experts here help me—I believe it is just about 2,400 megawatts.

Mr. CALVERT. So we are looking at about 700 megawatts of lost peak power; is that correct?

Mr. MCDONALD. Yes. Except I think I am getting corrected here. You are right. Thank you, Mike. I apologize.

At Glen Canyon, the installed capacity is about 1,300 megawatts.

Mr. CALVERT. So we are looking at about 400?

Mr. MCDONALD. About 400 megawatts reduction in capacity.

Mr. CALVERT. Mr. McDonald, what types of emergencies will allow the Bureau to deviate from operational plans to maximize power generation?

Mr. MCDONALD. At Glen Canyon Dam, Mr. Chairman?

Mr. CALVERT. At Glen Canyon or any other dam.

Mr. MCDONALD. Again, it is project-specific. In the Record of Decision that was adopted following the EIS on Glen Canyon Dam, there are specific emergency exception criteria. At Trinity reservoir and complex, which is a division of the Central Valley Project, we are in the process of likewise developing emergency criteria. We are operating in the Pacific Northwest right now pursuant to biological opinions just issued in December, and, again, they provide for deviations from those requirements if there is a system emergency. And, in fact, we have declared such an emergency, we being Bonneville Power Administration and Corps of Engineers and Bureau of Reclamation in that case, just a few weeks ago and are operating pursuant to those create.

Mr. CALVERT. I guess does that mean this summer if—in the Western grid if we have significant power outages, will Reclamation order additional power generation at those facilities—

Mr. MCDONALD. We are able to respond principally in three ways at the Central Valley Project, and, again, within the limits of scheduling for water deliveries—

Mr. CALVERT. How about Glen Canyon?

Mr. MCDONALD. —we can shape the peaks. We can do the same thing on the lower Colorado River at Glen Canyon if the exception criteria are met, number one, and, in the context of California, I would emphasize if transmission capacity is available, which is a very major constraint, because Glen Canyon was never meant to be a provider of electricity to California, so there is a significant lack of transmission.

Mr. CALVERT. Well, it is not just California. I think that the issue of power generation is not just a California issue. I suspect it is more of a Western grid issue. So if, in fact, there is a problem in the West—I don't want to define it just to California—do you perceive the Bureau of Reclamation making emergency declarations to get power online?

Mr. MCDONALD. If—again, in the context of Glen Canyon, if the exception criteria for an emergency are met—

Mr. CALVERT. And what do you mean by exception criteria? Will you let us know what you mean by exception criteria?

Mr. MCDONALD. Yes. In the Record of Decision in 1996, there were some specific criteria by which, on a short duration basis, usually a matter of 3, 4, 5 hours, we would operate outside the bounds of the criteria called for by the record of decision. Basically those criteria boil down to an emergency being a situation in which there is insufficient generating capacity. The transmission system is suffering from an overload voltage control or frequency problem. We need to run the generators for system restoration or, in the case of Glen Canyon, a humanitarian situation such as a search-and-rescue operation below the dam.

Mr. CALVERT. I think since—if it is the—Mr. Shadegg is here, and since we are on this subject, and this is in his district, if you would like to ask a couple of questions regarding Glen Canyon Dam, this is probably an appropriate time to ask it.

Mr. SHADEGG. Thank you, Mr. Chairman. It is—to be accurate, it is not in my district, but it is in my State, and we are interested in it.

The record of decision that you refer to, I guess, sets these criteria with regard to when you can have additional releases.

Mr. MCDONALD. Yes, sir.

Mr. SHADEGG. I am aware of, I think, three instances where—I believe—and you can correct me if I am wrong or spell it out in your answer—pursuant to that record of decision and under those criteria there have been three instances in the last, say, 6 months, maybe more, maybe 8 months, where there has been an additional release, and that has enabled the California power grid to stay up; is that correct? Are those—each of those releases been inconsistent with the criteria?

Mr. MCDONALD. They have in—those instances, in fact, are cited in my written statement, Congressman.

Mr. SHADEGG. My memory tells me one was in September, one was in December, and one was in March or thereabouts; is that correct?

Mr. MCDONALD. Assuming my written statement is correct, I think the ones we responded to were Stage 3 emergencies declared by the California independent system operator, and Western called upon us to generate, and it was an instance in September, one in February and twice in March.

Mr. SHADEGG. Okay. I guess the first question I would have would be is it your belief that those did any serious environmental damage, or is it your belief that those did not do any serious environmental damage in terms of what this Congress ought to be looking at as we approach a summer where there may be more of those?

Mr. MCDONALD. I simply have not seen data one way or the other on that. If you would like me to check, I would need to respond on the record. I am just not apprised.

Mr. SHADEGG. I would appreciate that because it is an important question. I mean, I think we want to know—I believe most of us are concerned about making sure that there is as much electricity as possible in the entire Western grid, particularly as we approach this summer where we know, I think, pretty reliably we are going to be short. If Congress has to make a trade-off, we want to do it on an informed basis, and so I would be interested in knowing whether there was environmental damage by those releases, and then second—and maybe you can supply us with that information later.

[The information referred to follows:]

Emergency releases made for California occurred on the following dates: September 28, 2000, February 15, 2001, March 19, 2001, and March 20, 2001. Most were for 4 to 5 hours in duration with the March 19, 2001 event taking place over 10 hours.

The existing program for monitoring resources below Glen Canyon Dam includes a monitoring schedule, depending on the resource and attribute being monitored, that means data is collected from two to six times per year. Given this schedule, the Grand Canyon Monitoring and Research Center(GCMRC) may not yet have the data to consider the before and after affects of these emergency releases. The field season for much of the data collection is just now beginning, and additional information is likely to emerge throughout the remainder of the year.

Therefore, the GCMRC does not have specific data, at this time, to determine if the emergency releases caused damage to aquatic resources. However, the three events in February and March coincided with the time of spawning of rainbow trout in Glen Canyon. These increased fluctuations may have caused stranding of redds (eggs) and their subsequent desiccation. Given the scale of current monitoring activities, we will only know the effect of these emergency releases one or two years from now when we evaluate the strength of this year class in the adult population and even then we may not be able to determine what events) during the year caused a change.

With respect to critical physical habitat such as sandbars and beaches, recent studies have shown that the sediment required to maintain the physical habitat is lost at an accelerated rate through such peak flows.

Mr. SHADEGG. Second, could you—should the Congress be looking at any change in those emergency conditions to allow additional power production, and if so, would that cause environmental damage, because I think everybody is interested in making sure we have electricity. Nobody is interested in doing environmental damage, certainly not any irreparable environmental damage or any that is gratuitous or unnecessary. And so that would be helpful to us if you or your staff—

Mr. MCDONALD. Okay. We will respond to both of those.

[The information referred to follows:]

The Final Environmental Impact Statement on the Operations of Glen Canyon Dam and the Grand Canyon Protection Act established an adaptive management program to cope with the uncertainties in our scientific understanding of how to manage complex ecosystems. It is based on collaboration, consensus and sound science. We believe this approach is the most effective way to develop appropriate management strategies to meet the interests of the American public including hydropower production, biological and cultural resource protection and recreation

Mr. SHADEGG. I think, Mr. Chairman, that is—

Mr. CALVERT. I thank the gentleman.

Mr. SHADEGG. Those are the questions I have.

Mr. CALVERT. Okay. I thank the gentleman.

I promised Mr. Cannon when he returned that he could give an opening statement, and then we will recognize Mr. DeFazio for questions.

STATEMENT OF THE HONORABLE CHRIS CANNON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF UTAH

Mr. CANNON. Thank you, Mr. Chairman, and I appreciate the opportunity to be here today. I have come because maximizing electricity production at the Federal facilities is an issue that is especially important to my constituents in Utah and to the West in general, and also I think a matter of major importance for the whole country and the economy of the country.

This year my home State and our Western neighbors are faced with a potential drought, although recent rains have, I think, helped that somewhat, and an electricity shortage. In Congress and back home we have been looking at ways to increase the supply of electricity. The problem is that new power plants and transmission lines take years to come online. However, it is important to continue investing in the infrastructure.

We should not ignore the potential of the facilities that already exist. It makes no sense to me that we are scrambling to prevent blackouts this summer while generators at Glen Canyon Dam sit idly each day during peak power demand because of environmental regulations.

Water from Lake Powell must be spilled at night when power demand is lowest and held back during the day when power demand is at the highest. Operating the dam this way has decreased peak power capacity by a third. This is enough energy for over 450,000 people. Instead of using clean, efficient, and emissionless hydroelectricity to meet power demand, utilities have been forced to buy from other energy sources, and the cost of buying this energy off the market is being passed right on to consumers, who are staggering under the burden. Glen Canyon Dam is already built. Its facilities are efficient, modern, and ready to use. The only thing holding us back from generating more electricity is regulatory red tape.

I appreciate the work Mr. Calvert and the Subcommittee is doing to make sure Federal dams are being used in the most efficient way possible. Again, I thank you for the opportunity to be here today and look forward to hearing from the rest of our witnesses.

[The prepared statement of Mr. Cannon follows:]

Statement of The Honorable Chris Cannon, a Representative in Congress from the State of Utah

Thank you Mr. Calvert, members, and witnesses for inviting me to address this hearing.

I have come here today because maximizing electricity production at federal facilities is an issue that is especially important to my constituents in Utah and in the West.

This year my home state and our western neighbors are faced with a potential drought and an electricity shortage. In Congress, and back home, we have been looking at ways to increase the supply of electricity. The problem is, new power plants and transmission lines take years to come online. While it is important to continue investing in infrastructure, we should not ignore the potential of the facilities that all ready exist.

It makes no sense to me that we're scrambling to prevent blackouts this summer while generators at Glen Canyon Dam sit idle each day during peak power demand. Because of environmental regulations, water from Lake Powell must be spilled at night when power demand is the lowest, and held back during the day when power demand is the highest. Operating the dam this way has decreased peak power capacity by one-third. This is enough energy for over 450,000 people!

Instead of using clean, efficient, and emission-less hydroelectricity to meet peak power demand, utilities have been forced to buy from other energy sources. The cost of buying this energy off the market is being passed right on to consumers who are staggering under the burden.

Glen Canyon Dam is all ready built. It's facilities are efficient, modern, and ready to use. The only thing holding us back from generating more electricity is regulatory red-tape.

I appreciate the work Mr. Calvert and this subcommittee is doing to make sure our federal dams are being used in the most efficient way possible. Again, I thank you for the opportunity to be here today, and look forward to hearing from the witnesses about this issue.

Mr. CANNON. Let me just add a question, if I might, to Mr. Shadegg. He talked about what environmental damage would be done if there was more peaking. Would you—is it possible to take a look at what would happen if we went through a prolonged period of regular daily discharges to meet more of that—or regular daily peaking need, rather than just the sporadic needs that we have met in the past?

Mr. MCDONALD. I think it is important to observe, Congressman, that the operation at Glen Canyon Dam now, why it certainly has increased the minimum flows that can be experienced, and decreased the maximum flows, and put limits on what we call uprates and—up-ramp rates and down-ramp rates; also have provisions for attempting to mimic the natural hydrograph that are well beyond those daily fluctuations for a few period—a few days in the spring, creating a spike in the river flow that is designed to redistribute sediment and in other ways replicate the natural ecology. So it is a much more complicated question than simply the more smooth daily operation that we have now relative to historic operations, because we are also doing some things for periods of time periodically each year that reflect the complexities of that ecosystem.

Mr. CANNON. So the question that I would appreciate you looking at is what would happen to the ecological system downstream if, for a prolonged period of time, you changed the current and changed the amount of flow so you met the peak capacity demands, particularly in southern California and Arizona on a regular basis, rather than just the four sporadic flows you mentioned that dealt with the response to the crisis in California?

Mr. MCDONALD. I certainly don't know the answer to that off the top of my head. Very complicated science there. I would be more than glad to respond for the record based on the numerous studies and vast wealth of data that is been gathered in the last 8, 10, 12 years.

Mr. CANNON. Great. Thank you very much.

[The information referred to follows:]

If release constraints were changed in the manner that you described, downstream change would most readily be seen with physical and recreational resources. Depending on the timing and duration of the subsequent releases both rainbow trout below Glen Canyon Dam and the rainbow trout fishery may be impacted. Recreational river running may be affected as boats are forced to navigate rapids under changing flow regimes and rafts and customers are potentially stranded on beaches. Sediment will be exported from the system at a higher rate and habitat will be degraded.

Mr. CANNON. Yield back.

Mr. MCDONALD. Thank you.

Mr. CALVERT. Mr. DeFazio?

Mr. DEFAZIO. Thank you, Mr. Chairman. Just following up on a point the previous gentleman made, I am wondering about transmission constraints, and I don't know who—whether the WAPA Administrator can address this or not, but, I look at the map that is provided on the back of the testimony by Mr. McDonald, and there is a transmission system constraints map, and I don't see any big black lines running to Glen Canyon. Where is that power? It looks like it runs sort of east and then north and then south and then west. Is that correct?

Mr. HACSKAYLO. Yes, sir.

Mr. DEFAZIO. So, is Glen Canyon really a potential additional source of supply in the crisis going on in California, or are we already transmission-constrained in terms of delivering that power even if it could generate more by, violating the constraints that protect the Glen Canyon?

Mr. HACSKAYLO. The difficulty in moving power from Glen Canyon to southern California is the lack of adequate transmission path into the southern California area.

Mr. DEFAZIO. Uh-huh.

Mr. HACSKAYLO. The power plant at the dam and the system surrounding Glen Canyon was designed to move power into the surrounding Basin States, not to California. Western has been able to move some of the emergency power to California during this past—these past crises by working on arrangements with other utilities to displace other power flows as we get closer to California.

Mr. DEFAZIO. Uh-huh.

Mr. HACSKAYLO. And in that—

Mr. DEFAZIO. Arrangements? We have arrangements? Are we going to move to a system of market-based transmission where constraints are resolved by the market as opposed to by these archaic agreements between utilities to exchange power and keep the lights on? Aren't you violating the edicts of the Federal—what do we call it—the Federal Energy Regulatory Commission?

Mr. HACSKAYLO. No, sir, not at all. I am pleased that—

Mr. DEFAZIO. That you are exempt from their harebrained scheme?

Mr. HACSKAYLO. No, sir. I would never call any scheme by FERC harebrained, and nonetheless, the utilities do cooperate in times of emergency on a hand shake or by contract—

Mr. DEFAZIO. Right. That is the old-fashioned way, but we are being told we are being driven toward an RTO in the West, and we are being told that despite the fact we have a constrained system, that what we are going to do is have a system that is based in markets, and the markets will tell us where it is constrained, and then they will send us a signal for 5 to 10 years every day, day in and day out, until we can rebuild or enforce that system. I just can't believe we are still allowing utilities to have handshakes and, work in emergencies and coordinate things and make the system work better. Why don't we practice this market-based system? Couldn't they get a lot more for the power? Couldn't they charge a lot more?

Mr. HACSKAYLO. I am not sure.

Mr. DEFAZIO. Okay. But anyway, we have got a transmission constraint out at Glen Canyon like we do in about 60 other places in the Western U.S.; is that correct?

Mr. HACSKAYLO. Yes, sir. That is correct.

Mr. DEFAZIO. Okay. Thank you, and I don't have any other questions right now, Mr. Chairman.

Mr. SHADEGG. Mr. Chairman, as a follow-up to that point, as I understood your testimony, whatever constraints are there, we have been able—and I think Mr. McDonald will confirm—we have been able to get power to southern California essentially, as I understood your testimony, by shifting it around, and the articles which I refer to which say—and I have three of them which I would be happy to put in the record which specifically credit Glen Canyon Dam with having avoided a shutdown of the grid. This one is an article dated March 21st. It says, grid officials credited the influx of 300 megawatts from the Glen Canyon hydroelectric plant on the Utah/Arizona border, and then they point out that is enough power for 225,000 homes. A second article from December 9, again, WAPA crediting Glen Canyon Dam; and a third one from September 25 crediting Glen Canyon Dam.

There may be, in fact, as pointed out, a transmission constriction, but it is not such that we can't get power there through a rotating basis; is that right?

Mr. HACSKAYLO. We can get power to southern California on an emergency basis as we did earlier, but if I may, I might point out that any additional power generated at Glen on a nonemergency basis already is under contract to be sold to customers in the States of Arizona and Wyoming and New Mexico and Colorado and Utah.

Mr. SHADEGG. Sure. So this is available for an emergency?

Mr. HACSKAYLO. That is correct.

Mr. SHADEGG. It was only able to be done in an emergency?

Mr. HACSKAYLO. That is correct, yes, sir.

Mr. SHADEGG. Thank you.

Mr. CALVERT. Mr. Osborne?

Excuse me. Without objection, those articles will be entered into the record.

[The articles referred to follow:]

ASSOCIATED PRESS NEWSWIRES

THURSDAY, MARCH 22, 2001

ANGLERS AT RISK: RIVER CAN RISE RAPIDLY IN POWER EMERGENCY

PHOENIX (AP) - California's energy crisis is turning the Grand Canyon in a fearful place for fishermen.

Twice this week, Bureau of Reclamation administrators have suddenly increased the flow of water from Glen Canyon Dam on the Arizona–Utah border to help meet California's energy needs.

The water powers huge turbines that generate electricity that can be shipped to California or elsewhere via a grid.

The suddenly rising water in the Colorado River can be a danger for anglers downstream or below the dam, who may have had little if any warning.

"I was out there with two clients," said Terry Gunn, owner of Lees Ferry Anglers Guide and Fly Shop. "And I noticed the water get murky. Then I heard the volume increase."

Anglers and campers could be caught in the flow at some places. They could be stranded. Their supplies on the river beaches could be washed away.

And there's no way to get a warning out on the river itself: The sound of a horn wouldn't travel far enough, and the canyon walls block radio waves.

This week's two emergency releases are half of all that have been needed in the past year.

March, April and May are prime fishing months for the 16-mile stretch of river immediately below the dam. The area known as Lees Ferry widely known for its trout - attracts fishermen in droves, with or without guides.

The average relatively low flow of 7,000 to 13,000 cubic feet per second leaves gravel bars and little islands that are great spots from which to fish.

On Monday and Tuesday, however, the flow through the dam was increased by more than 7,000 cfs in under two hours. Below the dam, the flow rose by more than 4,000 cfs in 20 minutes.

In some locations, that would raise the river's level by three feet in a similarly short span.

Reclamation bureau officials hope they get word of the need from the Western Area Power Administration farther in advance in the future, so warnings have be telephoned to guides and others. The administration brokers power throughout the West and determines where electricity from Glen Canyon goes.

"We've made a request to Western that we get at least an hour of warning before we have to ramp up," said Randy Peterson, a bureau official in Salt Lake City.

Overall, however, Peterson said, river users need to be aware that the water level can change suddenly and rapidly.

Dam operators called the guide services for this week's increases but only minutes before the new water made it farther downstream.

"We understand that's a power emergency, and there's nothing we can do about it," said Barbara Foster, owner of Marble Canyon Guides at Lees Ferry. "But a little more than five minutes' warning would be nice."

THE WASHINGTON POST

SATURDAY, DECEMBER 9, 2000

CALIFORNIA POWER GRID IS ON VERGE OF COLLAPSE; DEREGULATION, REPAIRS, POLLUTION CURBS BLAMED

William Booth
Washington Post Staff Writer

LOS ANGELES, Dec. 8—The statewide power system in California is teetering on the edge of collapse.

The governor has turned off the Christmas tree lights, the state has stopped pumping water from north to south, and universities and businesses are closing down early. But California is running out of juice—as demand for electricity outstrips supply in a deregulated market of wild price fluctuations and potential blackouts.

On Thursday evening, the state's electricity managers at the Independent System Operator facility declared the first-ever Stage Three power emergency, meaning electricity supply reserves had dipped to 1.5 percent of the demand. Rolling blackouts were narrowly avoided only because extreme measures were taken.

The emergency declaration allowed the managers of the state's power grid to order electricity that was on its way out of California to be brought back to the state. The grid was also saved by a last-minute surge of juice from the Western Area Power Administration, which sent electricity over the lines from its facility at the Glen Canyon Dam. And finally, consumers reduced demand. Some were ordered to do so, while others, such as the California Department of Water Resources, shut down the pumps that bring water from north to south for crop irrigation.

The Stage Three alert was canceled two hours after it was declared. Power supplies were meeting demand today, but energy managers said they feared for the coming days.

An official at the Independent System Operator said he was most concerned about rolling blackouts during the foggy evening rush hours, when traffic lights might suddenly go out.

The problems in California were heightened after the National Weather Service forecast that severely cold weather from the Arctic will descend on the central and western United States as early as Saturday and will continue into the following week.

From the western Great Lakes to the Great Plains, Rocky Mountains and then the Pacific Coast, abnormally cold temperatures are expected to accompany fast-moving snow storms.

The National Weather Service said today it appeared that the nation is finally returning to a "normal" winter after three years of mild winter weather.

An update from the Weather Service late Friday said there was a decreasing chance that the cold blast will hit California over the weekend.

In California, the energy crunch has been brought about by a combination of events.

Dozens of large and small generating plants are off line because of scheduled or unexpected repairs, or because they were shut down after reaching their allowed pollution limits for the calendar year.

Today, power usage was expected to peak at around 33,000 megawatts, while electricity generating plants that could have supplied about 11,000 megawatts of juice were shut down.

About 17 power generation plants—which together produce about 2,500 megawatts of electricity, enough to power 2.5 million homes—were idle because they had reached their pollution limits.

Managers of at least one electricity generator, San Diego Gas & Electric, complained that the power system is on the verge of collapse. They appealed to California Gov. Gray Davis (D) to declare a state of emergency and to issue waivers to allow the power generators to exceed their pollution limits during the energy crisis.

State officials who oversee pollution regulations vowed to ease the restrictions during the crunch.

Davis, whose administration is facing its first real challenge in the energy crisis, has blamed the power crunch on the deregulation of California's energy market—deregulation, he and his staff are reminding voters, that was done by the previous governor, Pete Wilson, a Republican.

"We're simply not ready for deregulation in California," the governor told the Associated Press. "California is riding point on this deregulation experiment. The problem is, I can't control the process. There are too many players."

In California's deregulated market, the first and largest in the country to open the power system to the free market, the electricity used is produced not only within the state but is also imported from outside California. While many states export and import electricity, in California the power is purchased the day before-and sometimes hours before—it is needed. This was expected to produce lower prices and a steady supply, but since last summer, supply and demand in the state have been out of whack.

The Federal Energy Regulatory Commission has labeled the California electricity market "dysfunctional." Several investigations are underway to see whether power suppliers are somehow manipulating the market. Davis and members of the Legislature are meeting to try to fix the problem. Among the possible solutions is a complete reversal of the current free market, in which the state would build and operate power plants.

DOW JONES ENERGY SERVICE

MONDAY, SEPTEMBER 25, 2000

U.S. DAM RESCUES CALIF GRID, BUT LAWMAKER DEMANDS MORE POWER

Bryan Lee
Dow Jones Newswires

WASHINGTON–(Dow Jones)- California averted a blackout last week with some help from the federal government.

The U.S. Bureau of Reclamation opened the flowgates at the massive Glen Canyon dam in Arizona, providing 300 megawatts of power for four hours in the afternoon of Sept. 18, according to federal officials.

The event illustrated how dependent the Western power grid is on electricity from U.S. government-owned dams, and highlighted the increasing political tensions that arise from the use of these assets as competition shakes up the nation's $215 billion power sector.

At a House Government Reform Committee hearing last Thursday, Rep. Doug Ose, R–Calif., demanded to know why, if the Bureau of Reclamation was able to help the state avert a grid emergency, it didn't make electricity available throughout the summer months when San Diego consumers paid twice as much for electricity as they did in 1999.

"This administration sacrificed the interests of consumers in San Diego," Ose declared.

But a Bureau of Reclamation spokesman said last week's emergency marked the first time the California grid operator had asked for help.

The Interior Department agency was prepared to act further by making power available from other dams later in the week, but the state's grid operator didn't ask for power, said the spokesman, Barry Worth.

Under a mandate from the Interior Department to restore riverbank beaches deemed critical for endangered wildlife, Glen Canyon has been operated for the last few years in a way that reduces net power production from the dam by about 900 megawatts.

The doubling of flows last Monday was within the restricted range required by the Interior Department, Worth said.

But he noted the agency was reluctant to do so out of concern it would interfere with a summer-long test of the impact on endangered species from drought-simulated low flows.

"The amount we increased was of concern to us initially because of our test, but we determined the amount was analogous to monsoonal thunderstorms we would normally get this time of year," Worth said.

"We wanted to make sure we were protecting our studies," he said.

Nevertheless, Worth noted that power from Glen Canyon doesn't normally flow to California to begin with. And he emphasized that transmission constraints don't make the state a natural destination for the dam's power.

Given the configuration of the Western grid, it is easier for California to get its power from other sources in the region, such as Hoover Dam, Worth said.

"We responded, but there's a limitation to how much we can (help) to begin with," he said.

Still, if California asks, the agency is prepared to help by providing power again, Worth said.

Mr. CALVERT. Mr. Osborne?

Mr. OSBORNE. Well, thank you for your testimony. A week ago we had some folks in from California, and they were talking about increasing their water storage by about sixfold, and, of course, some of it has to do with recycling, and some of it has to do with injection into other systems, but a lot of it has to do with ancillary dams and storage facilities that were not necessarily obstructing major waterways, but possibly capturing runoff. And what I was wondering is if you have any plans or see any likelihood of increasing your storage capacity?

Mr. McDONALD. I presume, Congressman, that you are referring to the—what we call the CALFED process, the process involving State and Federal agencies. It is been ongoing in California for about 6 or 7 years. It is looking at the issues associated with the Bay-Delta. In the context of that process and the joint Federal-State decision reached last August, there were a number of potential new reservoir sites identified in that process that will be subject to further investigation in the future. I don't recall, frankly, whether any of those have hydropower potential or not. I would be glad, again, to provide those details on the record, but there were about a dozen additional reservoirs, one of which included the potential enlargement of a Reclamation facility.

Mr. OSBORNE. Of course, I would assume if you had more water storage, it would increase your hydrocapacity, I mean, even if there were dams off the Glen Canyon, not directly on the dam itself, but you just had more access to water when you needed it. But I guess that was my question, whether you knew of any plans to construct any additional dams or storage facilities.

Mr. McDONALD. Reclamation certainly does not have any current plans to construct any new hydropower capacity.

Mr. OSBORNE. Okay. One other question I would like to ask you, and that is obviously you have been impacted somewhat on peaking power by the Endangered Species Act and some environmental concerns, and it may be hard for you to answer this, but do you feel that there has been sound science and good data behind those decisions governing the flows and trying to protect the endangered species?

Mr. McDONALD. I think Reclamation believes on the whole, yes, there has been the best available science brought to bear on those decisions.

Mr. OSBORNE. So at times you are varying your flows daily; is that right? I mean, some increased flows that—at night and reduced flows during the day?

Mr. McDONALD. The more typical change, Congressman, relative to a historical operation at any given facility is that we are not ramping up the release of water through a turbine or bringing it back down as rapidly on an hourly basis as was historically done. The water still goes through the turbine. We still generate the energy, but it is not placed on peak as much as was historically the case.

Mr. OSBORNE. Okay. Thank you.

Mr. McDONALD. Yes, sir.

Mr. CALVERT. Thank you.

Mr. Otter—or excuse me, Mr. DeFazio, do you have any additional questions?

Excuse me. Mr. Otter.

Mr. OTTER. Thank you, Mr. Chairman. I have a question relative to something that was asked earlier.

Is it Hacskaylo?

Mr. HACSKAYLO. Hacskaylo, Mr. Chairman.

Mr. OTTER. You can call me whatever you want, and we are even.

Okay. Is there anything close to the free-market system that has ever resembled the present power marketing, selling, delivery and control in California in your estimation? Is there anything close to the harebrained system that they have instilled down there that is even close to a marketplace discipline?

Mr. HACSKAYLO. I think Californians would agree that it is an experiment.

Mr. OTTER. Well, in the Northwest we call it suffering.

Mr. CALVERT. That is all right. I was going to object. We call it several things, Mr. Otter. But go ahead. I am sorry.

Mr. OTTER. My apology. What was the question?

Mr. CALVERT. It wasn't a question, just a comment. Some people call it an experiment. We call it a few other things, too, but go ahead.

Mr. OTTER. I thought I had mispronounced your name, too, Mr. Chairman. I wasn't sure. Anyway. I just want to pursue that, because the general public and the news media and some of those who would like us to believe that that was a failure in the marketplace discipline in California have failed to call it what it truly was, and it was a continued mucking about by the government in the marketplace system, and it was a failure in restructuring. You cannot have a free market if there isn't a free market of entry. There is no additional permits for plants down there, no additional production for hydropower or any other kind of power, and then you had a fixed price on the other end, a capped price on the retail market. Anybody that believes that that was a part of—or had any resemblance to a marketplace discipline has gotten their economics degree someplace that—someplace else at a university whose name I can't pronounce.

Anyway, let me move on to Mr. McDonald. Mr. McDonald, several weeks ago we got into a discussion about spilling water in order to click—fix valves on Arrow Rock Dam, which is the little dam between the Lucky Peak and the Anderson ranch on the Boise River flows. In repairing those dams—and I was assured and reassured and reassured again that we would spill no waters just to fix those valves. Has there been any thought to putting a pen stock there, some hydroproduction capacities, while you are fixing those valves?

Mr. MCDONALD. Private parties, Congressman, in fact, have an application pending before FERC, and have had for a number of years, and they could choose to proceed through the FERC licensing process if they wish to do so. To my knowledge, Reclamation as a Federal agency has never considered putting a Federal power plant on that particular dam.

Mr. OTTER. And would the Bureau of Reclamation have an opinion as to whether or not that that would be a good thing to do, and would you be in support of private sector asking to do that?

Mr. MCDONALD. I am not aware that Reclamation ever has taken a position on that particular proposal. Were it to go forward, it would go through a comment process. Reclamation's principal interest on any dam where there is a private party seeking a FERC license goes to mechanical, structural, operational kinds of issues just to ensure the integrity of the structure.

Mr. OTTER. Let's say that that were an eventuality that the permitting process did start. Do you think the Bureau of Reclamation would fight that? Would they have any resistance to that?

Mr. McDONALD. I really wouldn't have a basis to comment. I have no personal knowledge of what that proposal may entail.

Mr. OTTER. I see.

During the studies on the several lower—what we call the lower Snake dams, the four dams that were always in question relative to the salmon runs and the Endangered Species Act, were you personally involved in those studies as one of the action agencies?

Mr. McDONALD. No. The Corps of Engineers—those are all Corps of Engineer facilities, and they did the EIS and the planning study.

Mr. OTTER. But in that scoping process, didn't the Bureau of Reclamation join in?

Mr. McDONALD. Reclamation was involved, yes, as a cooperating agency.

Mr. OTTER. I see. But you personally were not?

Mr. McDONALD. Essentially not because most of that had happened before I became Regional Director in Boise.

Mr. OTTER. I see. And finally I would ask, Mr. McDonald, have we changed the mission—the overall original mission of the construction of some of these dams by rulemaking authority by agencies, in your opinion?

Mr. McDONALD. I would characterize it that we have a new set of statutes passed by Congress that we are now responsible to effect, examples such as ESA. That is the law of the land, and it is a condition that we now need to operate under.

Mr. OTTER. Uh-huh. Thank you very much.

Thank you, Mr. Chairman.

Mr. McDONALD. Thank you.

Mr. CALVERT. Thank you, gentlemen.

Mr. DeFazio, any additional questions for this panel?

Mr. DEFAZIO. Well, I know in the Northwest—I was just looking through the Bureau of Reclamation's testimony, and I am not an expert on California water issues, but I am just curious when it talks about one of the constraints being contractual delivery of water. And in the Northwest we actually have—for purposes of generation and because of the drought—and I assume the drought is as bad in California as it is in the Northwest—we actually have the Bonneville Power Administration offering to purchase out people's contracts which saves BUREC from having to deliver the water which requires energy. It leaves more water in the river, which we can use to generate more energy, and, given the disastrous markets in part created through some of these poorly written free trade agreements, puts some farmers in better position than they would have been.

Is anything similar going on in California? I mean, has there been any attempt, is there anybody who could offer some substantial price to people who have delivery contracts to—because I notice here that you say in the summertime you actually can't even generate enough power to pump the water. You have to buy power. That is going to be unbelievably expensive in this manipulated market where you are looking at 300, 500, or currently for August $750 a megawatt hour to buy power in the manipulated market.

Mr. McDONALD. In the Central Valley Project, Congressman, this summer in the face of the water shortage, Reclamation is in the process of seeing if a substantial amount of water, probably in excess of 100,000 acre-feet, north of the Delta can be acquired from willing sellers from the Central Valley Project. I am not aware—I would defer to Mike from Western, if Western has proposed to buy back any load from project pumpers. I don't think we have and the Central Valley have. That is only—

Mr. DEFAZIO. If you buy back a water contract, you don't have to deliver that water. So that would save you some power, right?

Mr. MCDONALD. In the context of what is proposed in the Central Valley Project, this summer, Congressman, it would be water purchased north of the Delta that would still be moved into, through and to some extent pumped out of the Delta to the south—

Mr. DEFAZIO. Okay.

Mr. MCDONALD. —to relieve the shortage on the south side of the Delta with Reclamation contractors.

Mr. DEFAZIO. You are going to purchase water to deliver it to other water contracts.

Mr. MCDONALD. Yes.

Mr. DEFAZIO. As opposed to purchasing water to avoid, having to buy power and/or to augment generation?

Mr. MCDONALD. Right. This is not a proposition to reduce load on the system. It is to move water from the current side—

Mr. DEFAZIO. It is a different issue in California than it is for us in the Northwest.

Mr. MCDONALD. Yes it is. That is correct.

Mr. DEFAZIO. Just wanted to explore it. Thank you.

Mr. CALVERT. Mr. Stier, please explain the costs associated with BPA buying energy off the market. How much has BPA spent? Is there any number out there right now?

Mr. STIER. In what time period, Mr. Chairman, are we talking about?

Mr. CALVERT. Last year.

Mr. STIER. Well, I am not sure I can break out the power purchases. We can certainly do that for the record. Beginning this winter and heading into the summer, I know we have spent something on the record order of $500 million, both to purchase power and to purchase industrial and other load reductions in order to reduce our exposure to the market. So, we have spent a considerable amount of money on those two areas. I couldn't break them out individually right here, though.

[The information follows:]

BONNEVILLE'S POWER PURCHASES

In order to reduce Bonneville Power Administration (Bonneville) electric load and conserve water, between the start of December, 2000, and the end of April, 2001, Bonneville has purchased or curtailed over 3,600 megawatt-months of electric energy at a cost of over $500 million. In addition, Bonneville has netted about 500 additional megawatts-months of electric energy imported from California under our two-for-one electric energy exchanges. Total Bonneville short-term power purchases for all purposes, including load reduction, were $1.083 billion during the first half of fiscal year 2001. Based on published second quarter of fiscal year 2001 financial results, Bonneville now expects total fiscal year 2001 short-term power purchases to be $1.547 billion. Total fiscal year 2001 short-term power purchases were $624.9 million.

Mr. CALVERT. I have this same question also on Glen Canyon, and just for the record, how much generation capacity is lost in the BPA system as a result of environmental regulation? Is there any estimate on that?

Mr. STIER. Yes. I can give you an estimate. In the Federal Columbia River Power System, which includes the Grand Coulee Dam and the various Corps projects, since the 1995 biological opinion from National Marine Fisheries Service, which was the first biological opinion issued after we had listings in the Snake River stocks, has been derated by about 1,000 average megawatts of firm generation. So, the system was on the order of about 8,000 average megawatts of firm generation prior to 1995, and it is now something on the order of about 7,000 average megawatts.

Mr. CALVERT. So about 15 percent derating or so depending on—

Mr. STIER. Something like that. Right. We also, of course, as Mr. McDonald noted, lost a considerable amount of flexibility in terms of being able to follow loads on a daily basis. We also have some constraints in terms of seasonal generation because we are storing water now at times when we might not have stored it in the past.

Mr. CALVERT. What has been the result of that? How are the salmon doing this year?

Mr. STIER. Well, it is very complicated. There are so many inputs into the survival of these fish, it is really hard to say what is working and what isn't. But since a lot of these measures have been put in place, there have been substantial measurable survival improvements in terms of juvenile smolts migrating downriver through the system. We have also had a period where there have been pretty good ocean conditions. The fish spend most of their life out at sea. I think the general consensus is that at least some of what we are doing has been yielding results. We have had spectacular returns of adults this year, and there has definitely been an improvement in the stocks.

Mr. CALVERT. Do you think that there is a way that that can be reevaluated where you can continue to maintain good environmental policy, but potentially put more power on the grid?

Mr. STIER. Well, as Mr. McDonald pointed out, we have a provision in the Biological Opinions we operate under that allows us to declare a power emergency if we cannot meet certain criteria. Basically, those criteria are reliability criteria and financial criteria for Bonneville. We have declared a power emergency for this month, and it is likely to be extended pretty much throughout the summer season. That provision, we believe, gives us substantial flexibility to deal with the kinds of concerns we are looking at this summer, both in the Northwest and on the West Coast as a whole.

Mr. CALVERT. Okay. Any other questions? Mr. DeFazio?

Mr. DEFAZIO. Thank you.

What did you say the derated capacity of the system was with the additional constraints subsequent to the 1995 BIOP?

Mr. STIER. It is about 1,000 average megawatts of firm generation.

Mr. DEFAZIO. Right. But what is your total, then, rated capacity?

Mr. STIER. Well, the firm generating output of that system right now is just over 7,000 megawatts. That is not peak. That is just firm generation in a critical water year.

Mr. DEFAZIO. I was going to say that is a critical water year, and this is a critical water year.

Mr. STIER. This is actually slightly worse than the critical water year.

Mr. DEFAZIO. And what would it be in a better water year—let's say a normative average water year, what would the system capacity be?

Mr. STIER. Through the spring and summer of this year, we will have about 4- to 5,000 megawatts less generation each month than we had on average for the last 5 years.

Mr. DEFAZIO. Okay. So at 7,000, you are saying you could theoretically in a good water year come up with 11-?

Mr. STIER. Right. During the spring and summer. Right. When we have the runoff.

Mr. DEFAZIO. But not year round?

Mr. STIER. Not year round.

Mr. DEFAZIO. Then why did BPA sell 11,000 megawatts in its contracts?

Mr. STIER. Well, I think you know the answer to that story reasonably well. For the Chairman's benefit, we have contracts that go into effect in October. We are contracted to serve 11,000 megawatts of load. Our total system, including the nuclear power plant that we market the energy from, is about an 8,000 average megawatt firm generating system. There were a number of commitments made for a variety of reasons over the course of the 3-year subscription process, to allocate the power from this system. A year to 2 years ago it seemed reasonable to believe that Bonneville could go to the market, purchase the 3,000 megawatts of power that we were short at a price that was low enough that we could meld it in with the Federal system and essentially end up with virtually no rate increase. And of course what has happened in the wholesale electricity markets has turned that plan on its ear.

So how did we get there? We got there because there were a lot of folks that wanted a piece of the action. The Bonneville system was looking very good compared even to the markets a year ago, and we ended up oversubscribed.

Mr. DEFAZIO. Did the former administration pressure the Bonneville Administration to sign contracts with the aluminum companies who are not entitled under the Northwest Power Act to additional and continued power provision?

Mr. STIER. Mr. DeFazio, you are really putting me on the spot, aren't you? Well, let's see. How would I diplomatically answer that? I guess I would say something to the effect that Bonneville, consulting with the Department of Energy in the last Administration and with the region, felt that we could, with minimal impact on rates, accommodate about 1,500 megawatts of aluminum industry load, as well as provide approximately 1,000 megawatts of direct power sales to the investor-owned utilities in the region, which, of course, we had not done previous to this upcoming contract period. As I said, a year ago that seemed like a doable proposition without increasing rates generally, and at this point obviously it is not.

Mr. DEFAZIO. We have had—in the Northwest Energy Caucus, an informal group chaired by myself and Mr. Nethercutt, we have had testimony from public entities that every 100 megawatts purchased by BPA in the current projected markets would raise everybody else's rates by about 10 percent. Is that a ballpark—do you think that is pretty accurate?

Mr. STIER. To my knowledge, that is a ballpark figure.

Mr. DEFAZIO. So BPA has to purchase 2,500 megawatts for the IOUs and for the aluminum companies. They can't pass the costs on just to those consumers. They have to meld them into the system. That would mean that 250 percent rate increase for everybody else.

Mr. STIER. That is the worst case we are looking at.

Mr. DEFAZIO. But there are also other rate increases due to the drought and other constraints BPA has—in addition, I mean; 250 is not the top. Right?

Mr. STIER. I think the current thinking is that the worst case is probably somewhere between 200 and 300 percent.

Mr. DEFAZIO. Two hundred and three hundred percent wholesale rate increase?

Mr. STIER. Correct.

Mr. DEFAZIO. Okay. I just saw a statistic today which said that the Northwest on average—and this is a big surprise to me—in the spot market is paying more for wholesale power than—this was in a story about FERC adopting these measures yesterday, which are not going to really help Californians very much, but it said that we were actually paying more on average for wholesale power than Californians. It said 267. We are 267 over the last—how many months was that? Do you remember? It was in—it was one of the—I can't provide the article, but I am puzzled by that.

Mr. STIER. You know, I am getting a little out of my depth here.

Mr. DEFAZIO. Okay.

Mr. STIER. I can say something, though. I will respond to that in part though. I do know that the personnel at Bonneville who do our bulk power trading have a concern about price controls. Price controls in the recent past, in California, have tended to distort the Northwest market. That is because marketers who are subject to price controls in California, but not in the Northwest, are obviously going to take their product to the Northwest for a better price if they can get it.

Mr. DEFAZIO. Well, in fact, FERC's order of last evening exempts the Northwest and, in fact, for anybody it exempts outside of a Stage 1, 2 or 3 emergency, it exempts anybody who brokers power. So all one has to do within California is sell your power to a third party, and the third party can sell it without any restriction on price to other Californians. But obviously I get the idea what has been going on is—because in some ways what they have done to try and make power slightly more affordable in California is—has squeezed the balloon and sent some of that price to us then essentially. Okay. Thank you.

Thank you, Mr. Chairman.

Mr. CALVERT. Thank you, gentlemen.

If there is no further questions for this panel, we will adjourn this panel and move to our second panel. I thank the gentleman for coming out, testifying and answering our questions. You may have some additional questions that we may submit, and if you could answer those for the record, we would appreciate it.

Mr. CALVERT. Our second panel is Mr. Micheal McInnes, senior vice president/deputy general manager, Tri-State Generation and Transmission Association, Inc; Mr. David Wegner, board of directors of Glen Canyon Institute; and Mr. Rick Johnson, executive director for science, Southwest Rivers.

If the gentlemen will sit down, we will get going here shortly.

If the gentlemen will look at lights there on the table, that is the time indicator, and we try to limit the testimony to 5 minutes so Members can ask questions of the panel. So please try to summarize your remarks in 5 minutes or less, and we will start with Mr. Micheal McInnes. You may begin.

STATEMENT OF MICHEAL McINNES, SENIOR VICE PRESIDENT/ DEPUTY GENERAL MANAGER, TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Mr. MCINNES. Thank you, Mr. Chairman, members of the committee. I am Micheal McInnes, Senior Vice President and Deputy General Manager with Tri-State Generation and Transmission Association, Inc. I am also a member of the Colorado River Energy Distributors Association. I am sorry.

Mr. Chairman, members of the committee. My name is Micheal McInnes, Senior Vice President/Deputy General Manager with Tri-State Generation and Transmission Association. I am also a member of the Colorado River Energy Distributors Association, known as CREDA. I am honored to be able to speak to you today regarding Glen Canyon operations and the marketing of the Colorado River storage project resources, and some recommendations on the electric system conditions in the West.

Tri-State is a consumer-owned electric and generation—or generation transmission cooperative. We serve 44 distribution cooperatives that have approximately 487,000 consumer meters, and that translates into roughly a million people of population. Tri-State is the largest member of CREDA. We also have coal-fired and gas-fired generation resources, as well as over 5,000 miles of transmission lines.

CREDA members have entered into long-term cost-based contracts with the Western Area Power Administration for purchase of Federal hydropower resources out of the Colorado River Storage Project. Federal hydropower is marketed pursuant to marketing plans which have been developed through a public process, including an environmental impact statement process, and those resources, as has been mentioned today already, are marketed throughout New Mexico, Colorado, Wyoming, Utah, Arizona and Nevada.

Although Glen Canyon Dam has been called on to assist California three times during these periods of imminent blackouts, this support was provided as a part of WAPA's obligation to the Western Systems Coordinating Council, or the WSCC. CRSP resources are not marketed there on a firm basis, as has been determined through a public marketing plan process. The largest generating facility of the Colorado River Storage Project is the Glen Canyon Dam, located near Page, Arizona. In 1996, after many years of study and $104 million environmental impact statement, which was paid for by the CRSP power revenues, Glen Canyon operations were changed. As has been mentioned, approximately a third of that capacity was lost.

The EIS identifies the annual financial cost to the CRSP contractors at approximately $90 million. But this is in 1991 dollars, and it is probably three to four times greater than that in the market today. To date over $134 million has been spent on Glen Canyon studies and funded by CRSP power revenues, and this figure does not include the $8 million spent per year on the Adaptive Management Program.

Last summer, due to a Fish and Wildlife Service biological opinion, a low-flow experiment was undertaken. That experiment included low-flat flows, and it reduced generation when it lost the ability to load follow, which is one of the chief advantages of hydropower, that ability, as was expressed earlier, to ramp up and down quickly. The cost incurred by WAPA and funded by the CRSP revenues was approximately $55 million. The cost of the experiment alone in manpower and research was over $3.5 million, also paid by power revenues. The impact to Tri-State on this occasion was approximately $22 million.

The Western Energy market crisis is affecting all CRSP contractors and WAPA. As that generation is reduced at the hydropower facilities, some of that due to environmental constraints, have caused WAPA and the contractors to be out on the market. It is the same market that the entities in California are purchasing from. In order to mitigate, in part, the effects on this market crisis, Federal generating facilities should be directed to maximize operations from Federal hydropower facilities so as to produce the maximum amount of generation available within the existing legal constraints. They should also be encouraged to work directly with the stakeholder and funding entities in making the decisions that impact those operations, maintenance and capital improvements at the facilities. Stakeholder involvement, similar to the 1992 CREDA work program agreement, encourages system reliability improvements, while ensuring that economic impacts to customers are addressed.

The success of consumer-owned utilities that in this time enjoy stable rates can be attributed to a number of things. I would like to enumerate those quickly: a mix of generation and transmission facilities and resources, including hydropower, coal-fired resources and gas-fired plants; long-range forecasting, planning and construction work programs as opposed to these short-term market approaches that we see; a pragmatic approach to electricity supply and demand, where diversity of load and a sensible approach to providing reserves has created benefits that are more compelling than customer choice; and most importantly, that owner/stakeholder involvement and control.

It is our view that Federal hydropower facility operating agencies should be directed to maximize production from those facilities, recognizing existing legal constraints. Research or experimentation, which would reduce that generation output, should be temporarily suspended during crisis situations. CRSP resources are marketed under long-term cost-based contracts within a defined geographic scope, and they guarantee the repayment of the Federal investment in these power facilities.

CRSP contractors should not be responsible for the operational, legal or financial impacts associated with the Federal Government's assistance to California. And finally, Federal agencies should be encouraged to implement stakeholder involvement processes, particularly where the stakeholders are the funding source for those Federal programs. And I thank you today for allowing me to appear.

Mr. CALVERT. I thank the gentleman.

[The prepared statement of Mr. McInnes follows:]

Statement of Micheal McInnes, Vice President/Deputy General Manager, Tri-State Generation and Transmission Association, Inc., on behalf of the Colorado River Energy Distributors Association (CREDA)

Mr. Chairman, members of the Committee, I am Micheal McInnes, Sr. Vice President/Deputy General Manager of Tri–State Generation and Transmission Association, Inc., and a member of the Colorado River Energy Distributors Association (CREDA). I am pleased to have been asked to talk with you today regarding Glen Canyon Dam operations, marketing of the Colorado River Storage Project (CRSP) resources, and recommendations to improve electric system conditions in the West.

Tri–State is a consumer-owned electric generation and transmission cooperative located in the states of Colorado, New Mexico, Wyoming and Nebraska. Tri–State is a wholesale provider of resources to 44 distribution cooperatives, that in turn serve approximately 487,000 consumer meters representing a population of about 1 million people. A portion of Tri–State's resource base is comprised of generation from the CRSP, of which Glen Canyon is the largest generation resource. Tri–State also owns coal and gas-fired generation resources, as well as 5,348 miles of transmission resources.

Tri–State is also the largest member of CREDA, which is a non-profit organization representing consumer-owned electric systems that purchase federal hydropower and resources of the CRSP. CREDA was established in 1978, and serves as the "voice" of CRSP contractor members in dealing with CRSP resource availability and affordability issues. CREDA represents its members in dealing with the Bureau of Reclamation (USBR) as the generating agency of the CRSP and the Western Area Power Administration (WAPA) as the marketing agency of the CRSP. CREDA members are all non-profit organizations, serving nearly 3 million electric consumers in the six western states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming. CREDA members purchase over 85% of the CRSP power resource.

Tri–State and other CREDA members (contractors) have entered into long-term, cost-based contracts with WAPA for purchase of federal hydropower resources of the CRSP. These contracts provide for frequent rate adjustments in order to ensure repayment of the federal investment in the CRSP. Our purpose today is to provide some background on the operational changes at Glen Canyon Dam, to discuss the marketing area of the CRSP, and to provide suggestions that may assist market conditions in the Western United States.

The CRSP was authorized in the Colorado River Storage Project Act of 1956 (P.L. 485, 84th Cong., 70 Stat. 50), as a multi-purpose federal project that provides flood control; water storage for irrigation, municipal and industrial purposes; recreation and environmental mitigation and protection, in addition to the generation of electricity. This testimony will focus on the major power generation features of the CRSP, although there are several irrigation projects included in the Project. The CRSP power features include five dams and associated generators, substations, and transmission lines. Detailed descriptions of the CRSP facilities were provided in testimony provided to this Committee on March 7, 2001.

CRSP MARKETING AREA

Federal hydropower is marketed pursuant to law and marketing plans that have been developed through a public process. From the time CRSP resources were initially marketed, the allocations remained constant until September 1, 1989. In 1979, WAPA began its process of determining the amount of capacity and energy it would have available after 1989, and the criteria by which it would be allocated to customers (51 FR 4844, 2/7/86). This process resulted in the "post–89 contracts".

As part of this process, it was determined that CRSP resources were to be marketed pursuant to preference (section 9(c) of the Reclamation Act of 1939). Also through this process, it was determined that the geographic area into which CRSP resources would be marketed on a firm basis "did not include any portion of California." Based on discussion contained in the marketing criteria, it was determined that the loads and interest level in California did not warrant expanding the marketing area into that state. In addition, existing contractors had made application for the entire amount of generation produced by the CRSP. There was an environmental impact statement (EIS) performed on the post–89 marketing criteria. This criteria was again reviewed in 1998, when extensions to the long-term firm contracts were considered. As part of this process, it was determined that 7 percent of the existing CRSP marketable resource would be held for allocation to Native American and new customers, beginning in 2004. (64 FR 34414, 6/25/99). Also as part of this process, there was a public inquiry initiated by the Department of Energy, which was intended to assess whether changes to federal marketing criteria should be made, given the onset of deregulation. (63 FR 66166, 12/1/98). Ultimately, DOE found no change was required of WAPA's marketing criteria, which reaffirmed the concept that the cost-based rates and marketing criteria associated with the CRSP are still relevant, possibly even more so, in a deregulated environment. Current customers have committed to purchase the entire output of the CRSP under long-term contract, through 2024. These contracts ensure repayment of the federal investment, with interest, as well as provide a level of resource certainty, which is critical in current market conditions in the West.

GLEN CANYON DAM

Glen Canyon Dam is located near Page, Arizona and is by far the largest of the CRSP projects. Glen Canyon Dam began operation in 1964. The water stored behind the dam is the key to full development by the Upper Colorado River Basin states of their Colorado River Compact share of Colorado River water. The Glen Canyon power plant consists of eight generators for a total of about 1300 MW, which is more than 70% of total CRSP generation. The ability of the USBR to generate, and WAPA to market, the total generating capability of Glen Canyon Dam has been impacted over a period of many years, by various processes and laws.

In 1978 the USBR began evaluating the possibility of upgrading the eight generating units at Glen Canyon. This was possible primarily due to design characteristics of the generators and improved insulating materials. This upgrade was completed, and the generation was increased from about 1000 MW to 1300 MW. To fully utilize the unit upgrades would have required the maximum water release at Glen Canyon to be increased from 31,500 cubic feet per second (cfs) to about 33,200 cfs. The USBR also studied the possibility of adding new units on the outlet works to provide additional peaking capacity. The possibility of increasing maximum releases from Glen Canyon raised concerns with downstream users. After discussion with stakeholders, the Secretary of the Interior initiated the first phase of the Glen Canyon Environmental Studies.

Following many years of study, in July 1989, the Secretary announced the start of an environmental impact statement (EIS) on the operation of the Glen Canyon Dam, although no specific Federal action was identified for study. Meetings were held during 1990 to seek input into alternatives that should be considered, and the USBR determined the nine alternatives (including a "no action" alternative) to be studied. Meanwhile, in 1992, the Grand Canyon Protection Act (106 Stat. 4672) was signed into law. Section 1804 of the Act required completion of the EIS within two years. The EIS was completed and the Record of Decision (ROD) signed in October 1996.

The result of 15 years of studies and processes is that Glen Canyon operations were changed to reflect a revised flow regime; approximately one-third of the generating capacity was lost (456 MW). The EIS identified the annual financial cost to CRSP power contractors at $89.1 million per year. But this was in 1991 dollars and would probably be 3–4 times greater today, given energy market conditions. The cost of the Glen Canyon EIS was approximately $104 million, and was funded by power revenues collected from the CRSP contractors. To date, over $134 million has been spent on Glen studies, and funded by CRSP power revenues. This figure does NOT include the nearly $8 million per year spent for the Adaptive Management Program.

In April of 2000, it was determined that due to hydrologic conditions and requirements of a 1994 Fish & Wildlife Service biological opinion, a low flow summer experiment would be undertaken. The experiment included high spike flows in May and September, with low flat flows (8,000 cfs) all summer. The purpose was to gain information regarding endangered humpback chub conditions. The low, flat flows and hydrology, along with western energy market prices had a severe impact on power generation, requiring CRSP customers, and WAPA, to purchase replacement power to meet their resource needs.

The cost incurred by WAPA (and to be recovered from CRSP contractors) for this replacement power was $55 million, just for the summer. Twenty-four million dollars of this total is attributed to the low steady flow environmental experiment; the remainder is attributed to wholesale energy market prices. The cost of the experiment alone was over $3.5 million, funded by CRSP power revenues. These figures do NOT include additional costs to CRSP contractors that had to purchase or supplement their CRSP resource with purchases from the energy market. The impact on Tri–State was approximately $22 million.

GLEN CANYON ADAPTIVE MANAGEMENT PROGRAM

CREDA participates on the Federal Advisory Committee charged with making recommendations to the Secretary of the Interior as to operations of Glen Canyon Dam pursuant to the Record of Decision and underlying laws. Funding for the program (Adaptive Management Program) is through CRSP power revenues. Proposed funding for next year's program will exceed $10 million. On October 27, 2000, President Clinton signed the fiscal year 2001 Energy and Water Development Appropriations Act, which included language (section 204) capping the amount of CRSP power revenues that can be used for the Adaptive Management Program, at $7,850,000, indexed for inflation. Without this cap, the annual program would have continued to increase, with power revenues being the sole funding source. Now, the program will need to seek appropriated dollars in order to maintain the increased funding levels. CREDA supports other sources of funding for this program. CREDA also participates on the Technical Work Group through consultants, to ensure that good science and efforts to increase power production are considered.

CRSP contractors have paid, and continue to pay, the majority of costs at Glen Canyon, even while the Glen capacity has been depleted by about one-third. There are significant operating constraints on the remaining available capability, as required by the 1996 ROD. Recognizing the instantaneous nature of power generation as well as constraints contained within the ROD, the USBR and WAPA should be directed to operate the facilities up to the maximum parameters allowed under the ROD. Maximum fluctuations (down to minimum nighttime flows of 5,000 cfs) should be permitted, which would allow the generation from Glen to follow load more accurately. There have been situations in the past where minimum flows were held at 8,000 cfs in an attempt to placate certain resource stakeholders, who believed there would be negative downstream effects. Subsequent analysis has disproved that assumption. Additional generating resource should be made available to the CRSP contractors within operating restrictions.

MARKET ISSUE MITIGATION

I. GLEN CANYON: The western energy market "price crisis" is affecting all CRSP contractors and WAPA. Reduced operational levels at CRSP facilities and environmental constraints have caused WAPA and the contractors to be out "in the market" having to purchase resources to meet contractual obligations and to serve load. This is the same energy market from which California entities are buying. Unlike merchant generating facilities that are constructed and operated to make a profit for their for-profit owners and shareholders, federal hydropower facilities cannot be operated for for-profit purposes. Their cost-based rates include many cost components not attributable to merchant plants, and they are subject to operating restrictions which are generally more stringent than those placed on merchant facilities.

The CRSP resources are marketed by WAPA pursuant to law and marketing plans within a legally defined marketing area, on a firm basis to preference entities. And yet, by Presidential and DOE directives issued during 2000, WAPA was called upon on September 18, 2000 and again on February 15, 2001, to "ramp up" Glen Canyon to assist the California Independent System Operator avoid blackouts. Although sympathetic to the energy situation in California, CREDA has some serious concerns with a requirement that CRSP resources be made available to California. CREDA's concerns are operational, legal and financial. Current hydrologic conditions in the Colorado Basin indicate the potential for another dry summer. Water released this spring may not be recoverable when it is so desperately needed to meet summer peak demands. CRSP resources are committed under long-term, cost-based contracts with a legally defined group of contractors, who are located within a legally established geographic marketing area. From a financial standpoint, the CRSP contractors are the "guarantors" of the federal investment in the CRSP. Given the current financial situation of California power purchasers, CREDA believes the CRSP contractors must be provided protection from financial impacts which may result from Presidential or Administration directives which require WAPA to sell into the California market.

Existing operating parameters in the ROD provide a limited range of operating flexibility. The ROD contains maximum and minimum flow levels, upramp and downramp limits, as well as daily fluctuation limits. However, even within these constraints, the USBR and WAPA should be encouraged to maximize power production to the fullest extent possible. They should be directed to temporarily suspend any experimentation or research that would reduce power output. Research through the adaptive management program should center on ways to increase generation without significantly upsetting the balance of downstream resources, consistent with the CRSP Act's mandate to "maximize power production". Such research could also examine the potential for incremental generation enhancements.

II. STAKEHOLDER INVOLVEMENT: Electric system reliability, particularly during periods of limited resource availability, is critical to ensure delivery of electricity to the public. Decisions regarding system enhancements, particularly to the federal generating and transmission resources, must take into account both reliability and economic concerns. A good example of how this type of balance has been achieved is through a contractual arrangement among CREDA, WAPA and the USBR.

The common thread among CREDA members is that each one is a party to a CRSP firm power contract with the federal government. From CREDA's inception in 1978, the issue of CRSP rate development and application has been key to its mission. For many years, CREDA's only recourse when it disputed inclusion of costs or rate methodology was to file at protest at the Federal Energy Regulatory Commission (FERC). FERC has authority over federal power marketing administration rates, but only to a very limited extent. For several years, CREDA explored with the federal agencies mutually agreeable means of addressing rate issues. In 1983, the USBR and WAPA entered into an agreement that contained certain principles regarding power repayment study issues, rate issues and repayment issues. In addition, the agencies agreed to hold informal meetings with customers prior to proceeding with a formal rate process. Certainly, this was a step in the right direction.

During the years between the "1983 Agreement" and 1992, CREDA continued to work with the agencies to more fully develop what is informally known as the "1992 Work Program Review" process (Letter Agreement No. 92–SLC–0208). On September 24, 1992, WAPA, the USBR and CREDA executed a letter agreement that formally implemented procedures for customer review of CRSP costs. This agreement was codified in an amendment to the CRSP firm power contracts with each CRSP contractor. Under the agreement, CREDA is provided, semi-annually, detailed CRSP cost information from both agencies. There are procedures by which CREDA may challenge costs, as well as procedures by which disputes may be settled. Attempts to resolve disputes begin with negotiation, with the ultimate step being resolution under the Administrative Dispute Resolution Act of 1990 (P.L. No. 101–552, 104 Stat. 2736), which include arbitration. The federal agencies also agreed to cooperate with CREDA to implement alternative dispute resolution procedures in any proceeding before FERC.

The 1992 Agreement sets out specific timetables and describes the nature of the cost information to be provided to CREDA. CREDA retains the ability to seek resolution in a Court of Law, but has the obligation to first proceed through the remedies provided in the 1992 Agreement. The benefits of this arrangement accrue to both the federal agencies and to CREDA members. Members have the ability to scrutinize work plan information, including proposed capital improvements and replacements and operation and maintenance expenses, before the plans become "cast in stone". Many CREDA members own and operate generation and transmission systems; they are able to bring expertise and insight to the agencies regarding reliability improvements and alternative construction options. This has proved to be a beneficial relationship and has resulted in cost savings to the CRSP customers. The agencies benefit because the parties to the Agreement attempt to resolve disputed issues prior to the instigation of formal rate processes. In fact, since implementation of the 1992 Agreement, CREDA has not litigated a CRSP rate case before FERC. Recently, following extensive work on the part of all parties during 1999–2000, WAPA was able to defer a proposed rate adjustment in July of 2000 (saving contractors approximately $12 million).

The 1992 Agreement was unique at the time it was executed. It continues to be a good example of constructive stakeholder involvement with federal agencies, particularly when the stakeholders are paying the costs of the federal programs at issue.

III. TRI–STATE RECOMMENDATIONS: Tri–State operates over 1,650 megawatts of generation and more than 5,000 miles of high voltage transmission lines in its own behalf and for others as well as holding ownership interests in other generation and transmission facilities. As a cooperative, it is directed by its 44 member electric distribution cooperatives, representing nearly 500,000 consumers and a population of nearly 1 million. A cost-based, consumer-owned utility, it is dedicated to providing sufficient supplies and reliable energy at an affordable cost.

As a member-owned utility, Tri–State has operated under cost-based rates and rate stability in an increasingly volatile market, particularly in the western United States, where consumer concerns over supplies and costs are steadily increasing.

The success of consumer-owned utilities that enjoy stable, affordable rates can be attributed to:

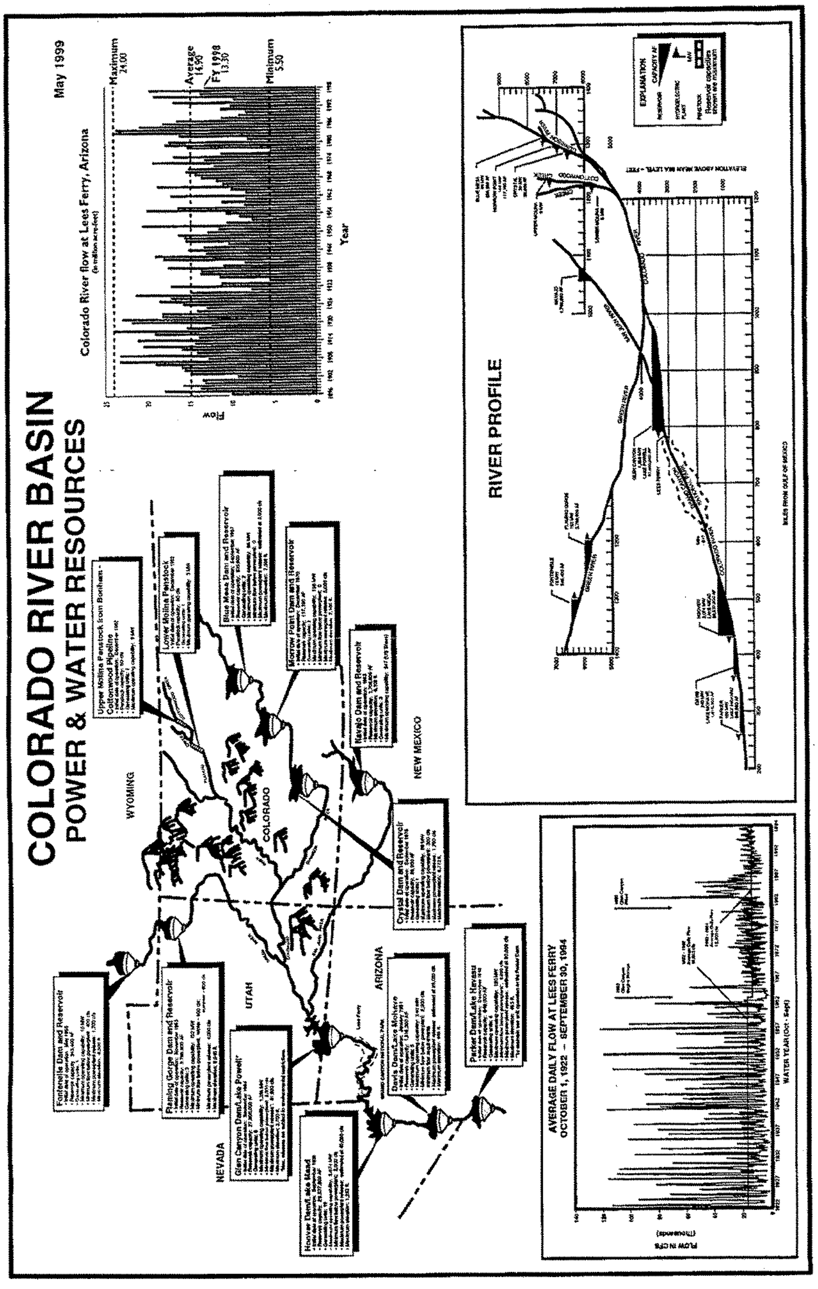
1. A mix of generation and transmission facilities and resources including hydropower as well as coal-fired and natural gas-fired plants.
2. Long-range forecasting, planning and construction work programs, as opposed to short-term market approaches.
3. A pragmatic approach to electricity supply and demand, where diversity of load and a sensible approach to providing reserves has created benefits more compelling than choice.
4. And most importantly, owner/stakeholder involvement and control.

CONCLUSIONS AND RECOMMENDATIONS

- Federal hydropower facility operating agencies should be directed to maximize production from those facilities, recognizing existing legal constraints. Research or experimentation that would reduce generation output should be temporarily suspended during regional power crisis situations. Research to increase generating capacity from these facilities, without significantly upsetting the downstream resource balance, should be undertaken immediately.
- CRSP resources are marketed under long-term, cost based contracts, within a defined geographic scope and guarantee repayment of the federal investment in power facilities as well as a very sizeable investment in irrigation projects. CRSP contractors must not be responsible for operational, legal or financial impacts associated with the federal government's assistance to California.
- Federal agencies should be encouraged to implement stakeholder involvement processes, particularly when the stakeholders are the funding source for federal programs.

Thank you for the opportunity to provide this information and appear before the Subcommittee today.

[A map attached to Mr. McInnes' statement follows:]


COLORADO RIVER BASIN
POWER & WATER RESOURCES
May 1999
Colorado River flow at Lees Ferry, Arizona
Maximum 24.00
Average 14.90
FY 1998 13.30
Minimum 3.50
Flow
Year
Fontenelle Dam and Reservoir
Flaming Gorge Dam and Reservoir
Glen Canyon Dam/Lake Powell
Hoover Dam/Lake Mead
Davis Dam/Lake Mohave
Parker Dam/Lake Havasu
Crystal Dam and Reservoir
Navajo Dam and Reservoir
Morrow Point Dam and Reservoir
Blue Mesa Dam and Reservoir
Lower Molina Penstock
Upper Molina Penstock from Bonham-Cottonwood Pipeline
WYOMING
UTAH
COLORADO
NEVADA
ARIZONA
NEW MEXICO
RIVER PROFILE
AVERAGE DAILY FLOW AT LEES FERRY
OCTOBER 1, 1922 – SEPTEMBER 30, 1994
WATER YEAR (Oct - Sept)
FLOW IN CFS (Thousands)

Mr. CALVERT. Mr. Wegner, you may begin.

STATEMENT OF DAVID WEGNER, BOARD OF DIRECTORS, GLEN CANYON INSTITUTE

Mr. WEGNER. Thank you, Mr. Chairman and the committee. My name is Dave Wegner. I live in Durango, Colorado, and I am here today representing the Glen Canyon Institute, which is a private nonprofit entity interested in environmental issues in the Colorado River Basin.

I am a scientist, and my perspectives today will likely differ considerably from some of the comments you have heard previously. For over 20 years, I worked for the Bureau of Reclamation and, in fact, was the project manager for the Glen Canyon Environmental Studies which have been discussed a bit today as spending money that the power users have put forth for environmental purposes.

I left the Department of Interior in 1996 and since then have been dealing with environmental issues and dam issues across the country on the Columbia and Snake River system, in Alaska and in many rivers internationally. I intend to summarize my comments today. I have provided you testimony which provides a more in-depth detail of the points I intend to make.

We are facing a challenge today. The challenge we face has many significant questions associated with it. Hydroelectric dams both built by the Bureau of Reclamation and the Corps of Engineers were built as multipurpose dams, primarily, though, with irrigation, flood control and flow management as their primary goals.

Hydroelectricity and hydroelectric generation was initially a secondary goal, which today has moved forward and in many cases it drives and is the primary reason why these dams are operated. The historic decisions on these dam priorities were made in a different time, prior to the passage of many of this Nation's environmental laws. Certainly at Glen Canyon Dam, which was authorized by Congress in 1956, there was no such thing as the National Environmental Policy Act taken in to consideration, and there was no Endangered Species Act. Today the challenge we are facing is finding ways to maintain the electrical integrity of this system and still meeting the mandates of these laws and rules and regulations that the people of the United States and this Congress have developed to protect our environment.

The quick and easy approach is to change the operations of the dam. They are the easiest to turn on and off. It seems like the simple solution. But we have to look further. We have to look at what is causing these problems in the first place.

Over the years the impacts of dam construction, operation and management have been widely debated and been the focus of many different scientific and administrative studies. The critical question that should be asked before any change is made in the management of these Federal dams is who is benefitting from the power during these emergencies? We should not be violating these agreed-upon environmental constraints, rules and regulations if the power is not being used wisely and being used clearly for emergency purposes.

Some of the findings that I have outlined in my testimony—and I will just summarize here—go to the core of this issue. First, the

California power crisis is a short-term issue. It has come upon the scene relatively quickly. Its cause has been well documented, both in the popular press and in studies and other testimony that you have heard in other committees. It is from the previous California State administration not looking forward to putting on-line more power plants. It wasn't taking into account clear and useful deregulation legislation. California has not adopted and developed an aggressive short-term conservation program, and the current shortage of electrical supply has developed largely as a result of poor planning.

As we have already heard today, many of our Federal power managers have oversubscribed the systems. Bonneville Power Administration, Western Power Administration, they sell more electricity than they have the ability to produce. Flow management has been reviewed extensively. In the case of the Colorado River and the Glen Canyon studies, we not only have gone through scientific review, but it has gone through legislative review, via the Grand Canyon Protection Act that has gone through judicial review, and we have gone through extensive administrative review. The environmental regulations at these Federal dams are not to be blamed for the problems that occur today. Last but not least, certainly if we continue to violate these rules and regulations, many tribal and Native American resources will continue to be impacted.

So in summary, what are some of our recommendations? First, we need to develop a clear and concise list of criteria and priorities for when emergencies really are to be called. We need to develop aggressive campaign and conservation actions to reduce the power demand. Many of the things that were applied in the 1970's in the last power crisis need to be relooked at. We need to develop irrigation buy-back programs for power. We need to evaluate every direct service industry to see indeed if there is a more effective way to manage our electricity, and last but not least, we need to look at how the reservoir systems are managed.

Providing more electricity at Glen Canyon Dam may not be the easiest solution. We have already heard that the power grid does not easily move electricity from Glen Canyon Dam to the California market. Perhaps it would be more appropriate to use Hoover Dam to do that.

In summary, the rivers of the Western United States have evolved over millions of years. We have to be looking forward to how we, as a group, as a society, can most effectively develop programs and criteria to evaluate and protect our resources. Thank you.

Mr. CALVERT. I thank the gentleman.

[The prepared statement of Mr. Wegner follows:]

Statement of David L. Wegner, Board of Directors, Glen Canyon Institute

INTRODUCTION

Good Afternoon. My name is David Wegner and I live in Durango, Colorado, near the Animas River, a tributary to the San Juan and the Colorado Rivers. I have been asked to provide you with my perspective on the importance of the environmental and other factors in the management of the Federal hydropower facilities in the West with specific reference to the Colorado River basin. Thank you for this opportunity. My perspective is likely not to be the same as the others who have testified before you today.

I am a scientist with over thirty years of experience and studies on river dynamics and environmental impacts. My background on this issue began on the Colorado River system in 1975 as a biologist on the Central Utah Project. During my career with the Bureau of Reclamation (1976–1996) I have had the opportunity to study the Colorado River system from the headwaters to the Sea of Cortez. Since I left the Department of the Interior in 1996 I have expanded and applied my knowledge of dam and river ecosystem relationships to the Columbia and Snake river systems, in Alaska, other rivers in the Great Basin, and internationally on rivers in Turkey, Germany, France, Russia, China, Siberia, Japan, Costa Rica and Vietnam. Many of the problems and challenges are the same.

I am here today as a representative of the Glen Canyon Institute, located in Flagstaff, AZ, and also representing the rivers and the species they support. I intend to address the specific question being asked by this Committee utilizing my expertise in the Colorado River system in combination with knowledge gained and drawn from other river systems in the West.

QUESTION BEING ADDRESSED

Does the current short-term electrical situation in California and potentially in the Western United States warrant modifying the environmental rules and regulations that have been developed for the Federal dams in the West?

BACKGROUND

The river basins of the West are controlled by multiple dams, irrigation diversions, and pumping plants. In the majority of cases, rivers with dams cannot support the historical assemblage or biological diversity of fish and wildlife species that historically were present. The largest dams in the Colorado River system are Federal and under the direct control of the Bureau of Reclamation with the hydropower being managed by Western Area Power Administration. There are over 60 Federal, State and private dams and 17 transbasin diversions that control the Colorado River plumbing system. In the Northwest, the Columbia and Snake River system is manipulated by both Federal and private dams. In the Northwest, the Corp of Engineers and the Bureau of Reclamation manage the dams while the Bonneville Power Administration manages hydropower distribution.

These water development systems were planned, approved by Congress and constructed prior to the passage of the majority of the environmental laws. The very laws that today make the United States one of the most progressive nations on the planet recognizes the importance of our river systems and the species they support. Congress has been instrumental in the development of the water and hydroelectric resources of the West and ensuring that the environmental species that depend on these rivers are considered as equal partners in the management of the federal dams and irrigation systems.

The rivers of the West are not what they used to be. This has been documented extensively in many scientific studies conducted by Federal, State, Tribal and private researchers. Today the rivers are fragmented, disjointed and severely modified from their former dynamic nature. The species that depend on these rivers provide economic benefit to the West. The Federal agencies that manage the rivers are under Congressional direction to ensure that environmental considerations are included in the management of the rivers. We are not here today to debate the value of the dams. It is scientifically documented and acknowledges that dams have seriously impacted river environments.

When the National Environmental Policy Act was signed into law, we, as an American people, recognized the importance of our environment and the species that are supported by them. With the subsequent passage of the Endangered Species Act, the Clean Water Act, Wild and Scenic Rivers Acts and other Federal legislation Congress recognized our responsibility for protecting species and their habitats. Many of the fish and wildlife species that have been recognized as endangered evolved and are dependent upon critical habitats and ecologically functional river systems.

Several examples of the evolution of environmental concerns in Western river basins are identified below. These efforts are specific examples of federally mandated actions intended to balance water and electricity management in the West and include:

- Colorado River Fish Program (1980's)
- Glen Canyon Environmental Studies (1982–1996)
- Grand Canyon Monitoring and Research Program
- Upper Basin Fish Recovery Program
- San Juan River Fish Recovery Program
- Flaming Gorge Dam Environmental Impact Statement

- Central Utah Project Environmental Impact Statement
- Central Arizona Project Environmental Impact Statement
- Lower Colorado River Multi–Species Conservation Program
- Northwest Power Planning Act (1980)
- Mid-Snake EIS (Bureau of Reclamation)
- FERC Relicensing Program for the Hells Canyon Complex (Idaho Power Company)
- Lower Snake River Dams EIS (Corp of Engineers)
- CALFED, San Francisco Bay–Delta Accord (2000)
- Trinity River Restoration EIS (2000)
- Multiple FERC relicensing efforts ongoing across the West

COLORADO RIVER SYSTEM AND THE EVOLUTION OF ENVIRONMENTAL CONCERNS

The Glen Canyon and Hoover Dams are the primary water control and electrical production facilities on the Colorado River system. In the case of Glen Canyon Dam the study of the impact of the operations of Glen Canyon Dam on the upstream and downstream environmental, recreation, economic, cultural and Native American issues began in 1973 and continues today.

- 1973—Biological Opinion on the operation of Glen Canyon Dam
- 1982—Secretary of the Interior James Watt initiated the Glen Canyon Environmental Studies
- 1987—National Academy of Science Review 1
- 1989 - Judicial review of the need for an environmental impact statement on power marketing criteria for the Colorado River Storage Project dams
- 1989—Secretary of the Interior Manuel Lujan initiates the Glen Canyon Dam operations Environmental Impact Statement
- 1990—National Academy of Science Review 2
- 1992 - Grand Canyon Protection Act (P.L.102–575)
- 1996—National Academy of Science Review 3
- 1995—FINAL Environmental Impact Statement on Glen Canyon Dam. Over 30,000 public comments received
- 1996—Experimental Flood–Environmental Assessment at Glen Canyon Dam (First application of Adaptive Management at Glen Canyon Dam)
- 1996—Record of Decision on the operations of Glen Canyon Dam
  - * Modified flow releases to protect endangered species
  - * Modified flow releases to protect cultural and public trust resources in Grand Canyon National Park and Glen Canyon National Recreation Area
  - * Modified flow releases to allow for power emergencies
- 1999—National Academy of Sciences Review 4
- 2000—Glen Canyon Institute—Draft Citizens Environmental Assessment on the decommissioning of Glen Canyon Dam

What these sequence of actions and efforts illustrate is that there has been a clear and direct effort made through Congress, the Executive Branch of the government, the courts and the scientific community to guide the management of the Federal dams on the Colorado River system to balance and protect the environmental resources. The decisions that have resulted have gone through extensive scientific, legislative, administrative, public, tribal and judicial review and approval process.

TODAY'S CHALLENGE

Today we are faced with challenges and significant questions related to the management of the hydroelectric dams in the Western United States. These dams were historically built as multipurpose dams, with irrigation and flow management as the primary goals. Hydroelectricity was a secondary goal that has evolved in many cases to be the primary driver for operations. These dams were built for development reasons with many subsidies built in to ensure that the Federal resource was used. The historic decisions on dam priorities were made in a different time, prior to the passage of many of this nations environmental laws. The subsidies of yesterday do not warrant loosing the important environmental resources of today.

The challenge is finding ways to keep the western electrical system whole and functional. The obvious and easiest first place to look is the hydropower facilities. They are easy to turn on, turn off, and have historically made up the slack for meeting short-term electrical needs. In the past, the issue would have been done without public input and discussion. That quick and easy approach cannot be taken today when other opportunities have yet to be explored.

Over the years the impacts of dam construction, operation and management have been the focus of multiple scientific and administrative studies. The result has been a refinement of the operations of many of the dams in an attempt to balance the environmental affects with management goals. The list of dam impacts in published, peer-reviewed documents is extensive and available if the Committee desires.

A critical question that should be asked before any change is made in the management of the Federal dams is Who is benefiting from the power during the emergency? We should not be violating agreed upon environmental regulations to provide subsidized power to pump subsidized water so that wealthy corporations can manufacture subsidized products or so that corporate farms can grow uneconomical, and subsidized, crops in the desert and leave us with diminished water quality that kills more species and further degrades marginal lands and habitats.

FINDINGS

In the course of developing this testimony, several findings are important to consider.

- The California power crisis is a short-term issue. It has been caused by:
  - * The previous state administration not approving any new power plants.
  - * Flawed state deregulation legislation
  - * Seven power plants are currently under construction and another six are on the fast track approval process
- California has not developed aggressive short-term conservation incentives.
- The current shortage of electrical supply has developed as a result largely of a poorly developed regulatory structure. No price caps have been implemented, no financial incentive structures are in place, and as a result, the public power financial capability has been negatively impacted.
- The Federal power managers have oversubscribed its contracts. As an example, Bonneville Power Administration has approximately 12,000 megawatts of contract responsibility in place and has the physical resources to supply only 9,000 megawatts. This requires BPA to purchase an additional 3,000 megawatts of energy on the open market at prices that are often from 4 to 10 times the cost of the federally produced power. The result, Federal financial shortfalls; the solution, don't oversubscribe capacity to produce.
- Flow management regulations in Western River system Federal dams have gone through extensive legislative, scientific, administrative and legal review
- Environmental regulations at Federal dams are necessary to balance ecosystem and social needs. These regulations have already been implemented without significant impact to Federal power contracts.
- Critical Tribal resources will likely be affected by rolling back of environmental regulations on Western rivers.
- Hydropower will continue to shrink in the overall energy production program due to diminishing capacity of the reservoirs, as sediment replaces the water and mandated water allocations restrict delivery ability.

RECOMMENDATIONS

The following recommendations are provided for consideration of this Committee:

- Closing the gap between electrical supply and demand through price mechanisms and conservation will go a long ways to alleviate the current electrical squeeze.
- A need exists to develop clear criteria and priorities that describe the circumstances for declaring a power emergency and actions that Western Area Power and Bonneville Power Administrations would need to take prior to such a declaration.
- Develop immediately aggressive conservation actions to reduce the power demand. This would include many of the same activities were implemented during the 1970's energy crisis:
  - * Turn off outdoor advertising signs and lights in public and private buildings when they are not being used.
  - * Develop irrigation power buy back programs with farmers
  - * Do not develop or operate Federal projects that use more electricity than they produce, such as the proposed Animas La Plata project.
  - * Evaluate every Direct Service Industry to see if Demand Side Management or other conservation activities could reduce their power requirements. Examples would be the current temporary shut down of several aluminum smelters in the Northwest
  - * Aggressively develop a campaign to educate the public on conservation measures
- Retire marginal agricultural lands that are growing subsidized crops that are dependent upon subsidized power for pumping water.
- Maintain higher reservoir levels at Reservoir Mead by drawing down Reservoir Powell. This has the benefit of minimizing evaporation loss at Powell and maxi-

mizing power production that can go directly into the California market from Hoover Dam. This would reduce transmission losses and maximize operational efficiency.

- The Glen Canyon Institute urges a measured, scientific program of reviewing dam management at all mainstem facilities and the development of ecological sustainable management of our rivers. This would include a complete economic evaluation of dams, identifying all subsidies and long-term restoration and maintenance costs necessary to provide a complete evaluation of dam impacts. Where scientifically and publicly supported, dam decommissioning and restoration of river systems should be implemented. In the case of the Colorado River, meeting electrical needs in California might be better met by focusing on maximizing Hoover Dam operations rather than utilizing Glen Canyon Dam.

SUMMARY

The rivers of the Western United States evolved over millions of years and support species and ecosystems that are economically important. The regional economics of the West are directly and indirectly linked to our river systems, whether it be for irrigation, water supply, salmon and other native species, recreation or hydropower. Native Americans, local communities and regions, and millions of people across the country and the world are dependent upon Congress providing clear and honest guidance in protecting our environmental resources for now and the future.

Development of the West has resulted in river systems that are constrained and unable to sustain environmental and economically important living resources without the regulations that have been imposed on the Federal dams and restoring ecological integrity. The long-term ecological sustainability for many of our rivers and the species that they support are at significant risk if the current regulations are ignored or administratively rolled back.

The current electrical situation in the West is one that has occurred because of poor planning, ill-planned and implemented deregulation actions in California, and the frenzy of private power interests who are poised to make considerable profit at the expense of the environmental resources.

The financial integrity of the Federal power agencies can be replenished as the electrical system becomes whole again. This will likely occur soon as additional power plants come on-line within the next twelve months. The damage done to the Rivers and the environmental resources during the electrical emergency cannot be replenished or brought back. The rivers and the species that they support should not be the ones to pay. Congress and the American public have, since 1970, consistently shown that the environmental resources should be considered equally with water and power. This is not a time or a place to violate the trust that the American public has put in its lawmakers and the responsibility that we all have to the future. I hope you can find the strength to do the right thing and fully explore all options to solving the electrical concerns before further compromising our rivers. Thank you.

Mr. CALVERT. Mr. Rick Johnson, you may begin your testimony.

STATEMENT OF RICK JOHNSON, EXECUTIVE DIRECTOR FOR SCIENCE, SOUTHWEST RIVERS

Mr. JOHNSON. Thank you.

Mr. Chairman, Members of the Committee, my name is Rick Johnson. I am the executive director for Science, Southwest Rivers. We are a nonprofit conservation organization dedicated to the protection and restoration of the rivers in the Colorado River watershed. I represent environmental concerns on the Glen Canyon Dam Adaptive Management Program, where I serve as a member of the Adaptive Management Work Group, which is a Federal advisory committee, and also as a Chair of the Technical Work Group. In addition to my own views, this statement also represents the views of Jeff Barnard of the Grand Canyon Trust and Andre Potochinik of Grand Canyon River Guide, both of whom also serve on the Adaptive Management Work Group.

Mr. JOHNSON. The flows of the Colorado River once fluctuated widely from year to year and season to season. The power of flood flows eroded and transported a tremendous load of sand, silt and other fine-grained sediment. Unique plants, animals and habitats evolved in these extreme environmental conditions. However, the extensive water developments have transformed the Colorado from a warm and sediment-laden river with highly variable flows to a relatively cool and clear river with stabilized flows.

These changes have had a profound effect on ecological, cultural and recreational resources in the river corridor. Key resources include native ecosystems, wilderness areas, world class whitewater rafting, blue ribbon trout fishing, archaeological and other cultural entities such as Traditional Cultural Properties, and threatened and endangered species such as the humpback chub, Kanab ambersnail and southwestern willow flycatcher. Dam operations have been implicated in the degradation of aquatic ecosystems through the loss of native fish and other species, the invasion of nonnative plants and animals, and widespread beach erosion. Dam operations have also diminished whitewater recreational experiences through the narrowing or rapids and the loss of camping beaches, and resulted in the erosion of archaeological and other culturally important sites.

Because of these ecological changes, dam operations are of great concern to many Americans. The concern is heightened at Glen Canyon Dam because Grand Canyon National Park lies just 15 river miles below the dam. Grand Canyon is one of the jewels of the National Park System, it is a World Heritage Site, it is considered one of the seven natural wonders of the world, and it is visited by 5 million people every year.

In response to the degradation of resources by dam releases at Glen Canyon, former Secretary Lujan ordered the preparation of an EIS in 1989. The EIS was completed in 1995 and the Record of Decision was signed in 1996. The goal of selecting the preferred alternative in the ROD was to find an alternative dam operating plan that would meet statutory responsibilities and permit recovery and long-term sustainability of downstream resources while minimizing impacts to hydropower capability and flexibility.

In the midst of the EIS process, Congress enacted the Grand Canyon Protection Act of 1992. In essence the act requires a balancing of benefits derived from water delivery and power production with benefits to biological, cultural and recreational resources. In addition, several other authorities have a bearing on how dams are operated, including the Law of the River, the National Park Service Organic Act, the Endangered Species Act and the National Historic Preservation Act.

The Glen Canyon Dam Adaptive Management Program was an outcome of the EIS process. The establishment of the AMP was a revolutionary decision in 1996, as it implemented the relatively new concept of adaptive management and, I think importantly, provided for ongoing input into management decisions by a diverse group of stakeholders.

The Adaptive Management Work Group provides advice to the Secretary of Interior regarding the effects of dam operations on downstream resources and any needed modifications to dam operations to meet the intent of the Grand Canyon Protection Act. The program serves as a model for resource management efforts in other areas. A recent National Research Council report stated that the AMP is a "science-policy experiment of local, regional, national and international importance.".

In conclusion, there are many biological, cultural and recreational values in addition to water delivery and hydropower production that the American public holds for the Colorado River. The Glen Canyon Adaptive Management Program is an outgrowth of an unprecedented amount of scientific research and public participation over the past 17 years. Grand Canyon means too much to the American public to sacrifice the integrity of this working partnership between local interests and the Federal Government. We recommend that the current operations at Glen Canyon Dam are maintained and any potential alterations be evaluated and recommended through the Adaptive Management Program.

I thank you for your attention to this very important matter, and I am happy to answer any questions you have.

[The prepared statement of Mr. Johnson follows:]

Statement of Rick Johnson, Executive Director for Science, Southwest Rivers, on behalf of Southwest Rivers, Grand Canyon Trust, and Grand Canyon River Guides

Mr. Chairman, members of the Committee, my name is Rick Johnson and I am the Executive Director for Science for Southwest Rivers, a non-profit conservation organization dedicated to the protection and restoration of the rivers in the Colorado River watershed. I represent environmental concerns for the Glen Canyon Dam Adaptive Management Program, where I serve as a member of the Adaptive Management Work Group (a Federal Advisory Committee) and also as the Chair of the Technical Work Group. In addition to my own views, this statement also represents the views of Geoff Barnard of the Grand Canyon Trust and Andre Potochnik of Grand Canyon River Guides, both of whom also serve on the Adaptive Management Work Group.

I am delighted to have been asked to speak with you today regarding the importance of considering environmental and other factors in the management of federal hydropower facilities, especially in the Colorado River basin. My focus today will be mostly on Glen Canyon Dam because that is the system I know the best. However, these comments also apply to many other hydropower facilities.

Dam operations affect biological, cultural, and recreational resources.

The flows of the Colorado River once fluctuated widely from year to year and season to season. The power of flood flows eroded and transported a tremendous load of sand, silt, and other fine-grained sediment. Unique plants, animals, and habitats evolved in these extreme environmental conditions. However, extensive water developments have transformed the Colorado from a warm and sediment-laden river with highly variable flows to a relatively cool and clear river with stabilized flows.

These changes have had a profound effect on the ecological, cultural, and recreational resources in the river corridor. Key resources include: native ecosystems, wilderness areas, world-class whitewater rafting, blue-ribbon trout fishing, archaeological and other cultural entities such as Traditional Cultural Properties, and threatened and endangered species such as the humpback chub, Kanab ambersnail, and southwestern willow flycatcher. Dam operations have been implicated in the degradation of aquatic ecosystems through the loss of native fish and other species, the invasion of nonnative plants and animals, and widespread beach erosion. Dam operations have also diminished whitewater recreational experiences through the narrowing of rapids and the loss of camping beaches, and resulted in the erosion of archaeological and other culturally important sites.

Because of these ecological changes, dam operations are of great concern to many Americans. The concern is heightened at Glen Canyon Dam because Grand Canyon National Park lies just 15 river miles below the dam. Grand Canyon National Park is one of the jewels of the National Park system, it is a World Heritage Site, it is considered one of the seven natural wonders of the world, and it is visited by five million people every year. The park is legally charged with protecting native biological resources and cultural resources, and it provides world-class recreational opportunities.

Hydropower production needs to be balanced with resource protection.

In response to the degradation of resources by dam releases at Glen Canyon Dam, former Secretary Lujan ordered the preparation of an Environmental Impact Statement (EIS) in 1989. The EIS was completed in 1995, and the Record of Decision (ROD) was signed in 1996. The goal of selecting the preferred alternative in the ROD was to find an alternative dam operating plan that would meet statutory responsibilities and permit recovery and long-term sustainability of downstream resources while minimizing impacts to hydropower capability and flexibility.

In the midst of the EIS process, Congress enacted the Grand Canyon Protection Act of 1992 which requires that the dam be operated to "—protect, mitigate adverse impacts to, and improve the values for which Grand Canyon National Park and Glen Canyon National Recreation Area were established, including, but not limited to natural and cultural resources and visitor use." In essence, the Grand Canyon Protection Act requires a balancing of benefits derived from water and power delivery with benefits to biological, cultural, and recreational resources. In addition, several other authorities have a bearing on how dams are operated, including the "Law of the River," the National Park Service Organic Act, the Endangered Species Act, and the National Historic Preservation Act.

An Adaptive Management Program is in place to ensure that the diverse interests of the American public are achieved.

The Glen Canyon Dam Adaptive Management Program (AMP) was an outcome of the EIS process. The establishment of the AMP was a revolutionary decision in 1996 as it implemented the relatively new concept of adaptive management and also provided for on-going input into management decisions by a diverse group of stakeholders.

Adaptive Management is a process to cope with the uncertainty in our scientific understanding of how to manage complex ecosystems. It is based on collaboration, consensus, and sound science. We believe it is the most effective way to develop appropriate management strategies to meet the interests of the American public—including biological and cultural resource protection, recreation, and hydropower production.

The Adaptive Management Work Group provides advice to the Secretary of Interior regarding the effects of dam operations on downstream resources and any needed modifications to dam operations to meet the intent of the Grand Canyon Protection Act. The Adaptive Management Program serves as a model for resource management efforts in other areas. A recent National Research Council report stated that the Adaptive Management Program for Glen Canyon Dam is a "science-policy experiment of local, regional, national, and international importance."

Conclusions and Recommendations.

1. There are many biological, cultural, and recreational values in addition to water delivery and hydropower production that the American public holds for the Colorado River.
2. The Glen Canyon Dam Adaptive Management Program is an outgrowth of an unprecedented amount of scientific research and public participation over the past 17 years.
3. Grand Canyon means too much to the American public to sacrifice the integrity of this working partnership between local interests and the federal government.
4. We recommend that the current operations at Glen Canyon Dam are maintained and any potential alterations be evaluated and recommended through the Adaptive Management Program.

I thank you for your attention to this very important matter and the opportunity to speak to you today. I am happy to answer any questions that you may have.

Mr. CALVERT. I thank the gentleman for his testimony. Mr. McInnes, within existing law what steps can be taken to increase power production from the Federal hydro-power facilities.

Mr. MCINNES. Well, barriers of new construction such as the ability to recover investment, environmental requirements which unduly delay and hinder development, and market theories that really serve no purpose other than to add layers of bureaucracy already should be done away with and those things studied. We certainly are in favor of doing things in an environmentally friendly way and living within those existing laws.

Mr. CALVERT. Do you have any suggestions on what can be undertaken to alleviate the western energy crisis in the short term and long term outside of what you just mentioned?

Mr. MCINNES. I think we just need to look at those impacts and make sure we have maximized the use of these facilities under existing constraints and laws.

Mr. CALVERT. Mr. Wegner, if the Glen Canyon Institute succeeds in developing a Citizens EIS, what do you think your next step would be to pursue decommissioning of the dam?

Mr. WEGNER. The Glen Canyon Institute has published a draft Citizens Environmental Assessment. Our intent was to encourage the Department of the Interior to take the next step to do the complete environmental impact statement to evaluate decommissioning as one element of the evaluation of the future for Glen Canyon Dam. If the Department of the Interior initiates that program, we would like to fully encourage participation by ourselves and other entities and hopefully get the full array of potential options for Glen Canyon Dam identified.

Mr. CALVERT. I was led to understand that your organization actually advocates the Glen Canyon Dam decommissioning.

Mr. WEGNER. We advocate the scientific evaluation of looking at that question and encourage people to evaluate that.

Mr. CALVERT. As you heard from today's hearing, we are trying to explore ways to alleviate the energy crisis not only in California but really in the entire West. If in fact Glen Canyon were decommissioned, what would be the source of the lost 1300 megawatts of generating capacity? Is that also being investigated through this process?

Mr. WEGNER. It certainly would be one of the elements in the Citizens Environmental Assessment but there are other alternatives that would also be looked at, such as conservation opportunities. We would encourage looking at better management of the remainder of the Colorado River system, looking at other sources of electrical supply, such as co-generation, other alternative sources, wind power, solar power, other opportunities that might be in the area.

Mr. CALVERT. How would the water storage capability of Glen Canyon be replaced?

Mr. WEGNER. Glen Canyon Dam was authorized by Congress to conserve water for the upper basin states. The delivery of water to the California market is still largely controlled by releases from the Hoover Dam. So the management of Hoover Dam and Reservoir Mead would need to be evaluated and taken into consideration in this process. In the short term the generation of electricity to meet the needs for California are better met from releasing more water through Hoover Dam because of the transmission capability. Capacity from Hoover is directly connected into the California market, where, as we heard earlier this afternoon, Glen Canyon is not.

Mr. CALVERT. You are aware that Hoover is already at maximum capability at the present time. We cannot pull more power out of Hoover, and also in that testimony I point out that electric power is somewhat fungible. We are doing trade agreements with the various folks in order to deliver electricity outside of using existing distribution lines. What about the impact on recreation in the blue ribbon trout fishery below Glen Canyon Dam? If the dam were decommissioned, what would happen to that?

Mr. WEGNER. The Glen Canyon Institute's Citizens Environmental Assessment addresses that. There would be several ways to decommission the dam and it certainly would not occur overnight. If it were to occur, it would likely happen over a 20-year period of time. Therefore, the recreational industries downstream of Glen Canyon Dam through the Grand Canyon would not likely be directly impacted at all. The trout fishery that currently exists below Glen Canyon Dam is an artificial trout fishery. It was not there pre-dam. Changes would happen over time to that fishery. And as is already in existence below Glen Canyon, Grand Canyon National Park is actually already managing for the native fishery and not for the trout fishery. Certainly changes would occur. Certainly the trout fishery would need to be looked at, and it would be evaluated through the Citizens Environmental Assessment.

Mr. CALVERT. In that case does Trout Unlimited, for instance, do they support your position in this?

Mr. WEGNER. I have not asked them directly about that.

Mr. CALVERT. If in fact the trout fishery did not exist any more, I suspect they wouldn't be too enthusiastic about it.

Mr. WEGNER. No, but on the other hand, Trout Unlimited has been very supportive in other ecosystems and other rivers around the country where they are looking at restoring trout fisheries and native fisheries.

Mr. CALVERT. But not necessarily this one here at Glen Canyon?

Mr. WEGNER. I have not asked them directly, sir.

Mr. CALVERT. Lastly, the committee is aware when you worked for the Bureau of Reclamation you were deeply involved in the Glen Canyon Environmental Studies that led to the EIS and the Record of Decision.

Mr. WEGNER. That is correct.

Mr. CALVERT. The key feature of the Glen Canyon ROD is the concept of adaptive management, which means the dam operations will not be fixed in concrete forever, but you can adjust those to reflect new science, new data. In your role as the head of the Glen Canyon Institute, do you support the concept of adaptive management?

Mr. WEGNER. On the interim basis, and the operations of Glen Canyon Dam, I wholeheartedly support the utilization of adaptive management. As the author of the original adaptive management piece for the environmental impact statement, the ROD still stands on good science and a good way to balance the needs. However, if the dam were to be decommissioned, you would have to reevaluate that whole process.

Mr. CALVERT. Okay. Mr. Johnson, your statement says that you represent the views of Jeff Bernard of the Grand Canyon Trust and the Grand Canyon River Guides. Does this mean that those groups also support your testimony?

Mr. JOHNSON. Yes, that is the case.

Mr. CALVERT. Could you please explain to the committee the process used with the Adaptive Management Program to develop flow recommendations?

Mr. JOHNSON. Actually right now we are in the process of doing that, and the process is that we have an experimental flow group, which is an ad hoc group which is part of the Technical Work Group. They get together with the scientists. They determine what are the major outstanding questions, research questions, that need to be answered and how they might be answered with different experimental flows. Those flow recommendations are then brought to the full Adaptive Management Work Group and then when we have the appropriate triggering criteria to run flows of different types, then those are done, as was done last summer with the low steady summer flows.

Mr. CALVERT. How does this management group work with the Bureau of Reclamation, which is the owner and operator of that dam? How does that work?

Mr. JOHNSON. The Bureau of Reclamation is part of the Adaptive Management Work Group and their staff have been very involved and helpful in virtually every one of the subcommittees, the Technical Work Group and the Adaptive Management Work Group.

Mr. CALVERT. What was the downstream resource impact on the last summer's steady flow of testing at Glen Canyon?

Mr. JOHNSON. If I wasn't here today, I would be in Flagstaff learning about that. There is a science symposium going on right now, which is the initial reporting of the results from the flows from last summer.

Mr. CALVERT. We would ask that the full written text of that be entered into the record.

Mr. CALVERT. CREDA has testified that the impact of low steady flow regime on power users was $55 million. What was the impact on recreation?

Mr. JOHNSON. From an economic perspective?

Mr. CALVERT. Yes.

Mr. JOHNSON. I am not aware of what it is on an economic perspective.

Mr. CALVERT. Any estimates?

Mr. JOHNSON. No.

Mr. CALVERT. General feelings?

Mr. JOHNSON. My guess is that it probably had minimum economic impact. It certainly had an impact in terms of running flows of 8,000 or flows that a lot of river guides had never seen before and it took some of the guides some time to figure out how to run rapids at that level. I know there were at least three boats running hung up with rocks that had to evacuate, and so there was that economic impact but a dollar cost involved with that I don't know.

Mr. CALVERT. Mr. DeFazio, do you have any questions?

Mr. DEFAZIO. No, I am here for the next panel, Mr. Chairman. Thank you.

Mr. CALVERT. There are no questions. So we appreciate this panel for coming out and answering our questions and testifying.

We will be happy to introduce our next panel. Our next panel is Mr. James C. Feider, Electric Utility Director for the City of Redding; Ms. Aleka Scott, Transmission and Contracts Manager, Pacific Northwest Generating Cooperative; and Mr. Richard Erickson, Secretary/General Manager, East Columbia Basin Irrigation District.

If you will please take your seats, we will ask you to begin your testimony. You have a timer there in front of you and it indicates when we get to 5 minutes by a little red light coming on. We would appreciate if you keep your remarks to 5 minutes or less so we have time to entertain some questions. With that, Mr. Feider you may begin.

STATEMENT OF JAMES C. FEIDER, ELECTRIC UTILITY DIRECTOR, CITY OF REDDING

Mr. FEIDER. Thank you, Mr. Chairman. It is a pleasure for me to be here from the City of Redding. I am the Director of the Electric Utility for the City of Redding, and I come from the perspective of being close to the customer and I face our customers every day on the streets of Redding and they are concerned with what is going on in the deregulation fiasco in the State of California. I am pleased to be here to also represent The Northern California Power Agency because Redding and other members of NCPA rely heavily on the Central Valley Project for the resources to serve their customers. It is vital to our communities to have that cost based resource to provide price stability and reliability to our communities.

The Central Valley Project has excellent flexibility to provide peaking power on a daily basis. However, it has a need for baseload energy and in order to provide that baseload energy, the Western Area Power Administration has a contract with the Pacific Gas & Electric Company, where it trades the peaking capability to provide firming energy. We are quite concerned as we sit here today that PG&E is trying to unwind that arrangement and pass through market rates instead of the cost based rates that that contract was based on.

I would like to touch on the generation and transmission aspects of the projects as well. The customers like Redding have been working closely with the Bureau over the last several years to optimize the power output, and we were quite pleased to be able to be participate in the Shasta rewinds that have now been completed. We are looking forward to turbine replacements at Shasta Dam, and we encourage this committee to support further turbine and upgrade activities at the power plants.

I appreciate the comments made by the Bureau of Reclamation witness about maximizing off-peak pumping. We would also encourage Western to have some of its unique customers to also do off-peek pumping, and I should say also off-peak use of their facilities. For example, at the Ames Wind Tunnels in the South Bay area could be further optimized for off-peak purposes.

On the Trinity River operation we are quite concerned with former Secretary Babbitt's decision that was made last year. We think that a more balanced approach ought to be taken. We see that as a significant hit to both water supply and power supply in the State of California. We think a more common sense approach should be used in moving forward.

With regard to the Bureau looking at emergency procedures, we are concerned that procedures might be too late if the water is also released. So we would like to see again a balanced approach.

With regard to transmission constraints in the State of California in particular, Redding and other municipal utilities in NCPA support the fix of so-called Path 15 in central California that you have heard about. The Federal Government has played a strong role in the past several dozen years on intertie transmission capacity, and we see the Western Area Power Administration to be the instrumental agency to get Path 15 fixed.

One of the activities going on as we speak is the biological surveys. We understand that PG&E has undertaken the biological surveys, although they say they are not in a position to proceed with the construction of that project. So we think the Western Area Power Administration should provide a key role in facilitating that project either as the lead Federal agency for NEPA purposes or going forward on the planning and construction aspects. We encourage this committee to pay attention to the Fish and Wildlife aspects of this project because the biological surveys will have to be submitted to Fish and Wildlife for their consideration.

The last point I would like to touch on is what I call organizational flexibility. As you know, we are in a crisis in California and Federal agencies like the Bureau and Western are to be commended for their ability to operate on a daily basis to optimize the assets they have. Oftentimes they have to live with the constraints that have been referred to here today. But on a day-to-day basis we are pleased that they are optimizing those resources. However, we think they need flexibility to respond to the changing conditions. Not only do we have price instability, but we also seem to have regulatory instability, and we would like to see those agencies to have adequate staffing and funding alternatives by those of us who are paying the bills.

And with that, I will conclude my remarks, and again thank you for the opportunity to be here.

[The prepared statement of Mr. Feider follows:]

Statement of Jim Feider, General Manager, Redding Electric Utility Department, City of Redding, California

Mr. Chairman and members of the Subcommittee, I appreciate the opportunity to testify on behalf of the City of Redding, California, and the Northern California Power Agency (NCPA).

As Director of the Redding Electric Utility and as an active participant in NCPA's work with the Western Area Power Administration (Western) and the Bureau of Reclamation (Bureau), I deal extensively with the components of the federal power program. Federal power from the Central Valley Project is a vital component that NCPA's not-for-profit community members rely on for reliable power at affordable prices.

The value of the Central Valley Project, also known as CVP, lies in three subjects that I will focus on today: Generation, Transmission and Organizational flexibility.

The CVP has been a vital source of generation for NCPA members, including the City of Redding. It was built to optimize the flexibility inherent in hydroelectric generation for ramping up during the peak load hours of the day. However, the actual kilowatt hours produced by the CVP fall far short of being a good match with customer needs especially during dry years. That is why Western has historically purchased so-called firming energy to better utilize the federal system and to best match customer needs. Western's utilization of its Pacific AC Intertie facilities has been key to the overall success of the federal power program.

Also key to the program has been the resource integration agreement with Pacific Gas and Electric Company (PG&E).

This arrangement was created in 1967 to eliminate the need for the Bureau to build a base-load, thermal generating station. Unfortunately, PG&E is currently attempting to unwind this longstanding contractual obligation to provide cost-based firming energy to Western through 2004. We recommend that the Subcommittee track this substantial economic threat to the federal power program.

NCPA members have been very active over the last ten years to ensure proper maintenance and upgrades to the CVP generating facilities. We are pleased with recent progress made by the Bureau. For example, advance customer funding to upgrade three generators at Shasta Dam have resulted in increasing Shasta peaking capacity by about 50 MW. Turbine replacements allowing further power production enhancements are underway at Shasta. NCPA believes that turbine replacements at New Melones, Carr and Spring Creek Power Plants also have merit. We ask the Subcommittee to support acceleration of these potential upgrades.

With regard to reoperation of the Trinity River, we do not believe the alternative selected by former Secretary of Interior Babbitt in his December 19, 2000 Record of Decision (ROD) represents a balance of competing resource needs in California. In light of the ongoing energy crisis in California and along with growing concerns over the adequacy of our water supply, we do not support the substantial increase of water releases down the Trinity River. We are astounded that the ROD would be implemented during constant threats of rolling blackouts especially given that the fisheries on the Trinity River have recently improved.

NCPA definitely supports stepping up further fishery improvements such as mechanical work in the Trinity River bed to improve fish habitat, and we may support some additional water flow as we submitted during the public process.

We urge the Subcommittee to support a more balanced decision-making process on any future Trinity decision.

With regard to transmission, NCPA would like to see the federal government build upon the success story of the California Oregon Transmission Project. This 340-mile, 500kV Intertie was completed in 1993 as part of a joint effort between Western and 20 public power utilities. Western's lead role in this project, where 180 miles of existing federal lines were upgraded, was in large part the reason for its success.

Western has congressional authority to further enhance the Pacific Intertie system and could facilitate completion of Path 15 improvements—the transmission bottleneck between Northern and Southern California. NCPA believes that with an immediate infusion of federal funding that Path 15 restrictions could be fixed in less than two years. The most important critical path item is to complete biological surveys right now during the spring blooming season. We recommend that the Secretary of Energy be requested to reprogram current year funds immediately for this purpose. In addition to supporting Western's role as lead agency, we would like to see Western proceed with work on the design and land acquisition activities for this project. It is important to note that any federal funding for this effort should be reimbursed back to the federal government through user fees or converted transmission rights as deemed appropriate for the benefit of the federal power program.

Mr. Chairman and Subcommittee members, California is in a serious crisis. The federal power system is a vital part of California's energy picture. Both the Bureau and Western are to be commended for their daily efforts to optimize generation and transmission assets not only in partnership with their customers, like Redding, but also for close coordination with the California Independent System Operator.

As a final point, there is a need for agencies, like the Bureau and Western, to have considerable flexibility in times of crises. Federal agencies, which operate significant real power facilities in real time, need more flexibility to fund and staff their organizations to meet constantly changing circumstances. NCPA recommends that Western and the Bureau be given more authority to adjust staffing levels and alternative funding mechanisms when supported by those paying the bills. Any increased expenditures would not be borne by the taxpayer, but rather through Western's customers.

I thank you for the opportunity to testify and would be eager to answer any questions.

Mr. CALVERT. Thank you. Ms. Aleka Scott, you may begin your testimony.

STATEMENT OF ALEKA SCOTT, TRANSMISSION AND CONTRACTS MANAGER, PACIFIC NORTHWEST GENERATING COOPERATIVE

Ms. SCOTT. Thank you. Good afternoon and thank you for giving me the opportunity to update you on RTO West, the transmission restructuring effort now occurring in the Pacific Northwest and other States. I am Aleka Scott. I am the Transmission Manager for the Pacific Northwest Generating Cooperative, which is an energy services co-op serving the electric power and transmission needs of 15 rural electric co-ops in the Pacific Northwest. Because of our extremely transmission dependent nature, PNGC as a cooperative and I personally have been involved in all of the transmission restructuring efforts in the past 7 or 8 years.

The latest restructuring effort is RTO West organized by the Bonneville Power Administration and the eight investor-owned utilities in the States of Oregon, Washington, Idaho, Montana, Nevada, Utah, and parts of Wyoming. While a robust public process, including participation by transmission owners, users and other stakeholders, has been established by the IOUs and Bonneville, collectively known as the Filing Utilities, ultimately it is the transmission owners, the Filing Utilities who will decide the content of the RTO Westfiling.

Where are we today on RTO West? The Filing Utilities; that is, the owners, filed their Stage 1 filing with FERC on October 23, 2000. They asked for a review of governance, scope and configuration and liability. Work has continued from that day to this on the issues. FERC just yesterday issued an order on RTO West. Stage 2 was supposed to be ready in July of this year, but given the lateness of the FERC order and the enormity of the task before us and the possibility of unintended consequences of transmission restructuring, I would hope that as a region we take the time we need to get it right.

FERC's order yesterday did affirm the basic governance and scope and configuration and liability parameters of RTOs. However, what was not filed in the Stage 1 filing and what remains at the heart of the RTO West debate is the congestion management and transmission expansion proposal; in other words, how short term congestion is managed and who decides when to expand the transmission system. You have heard from many of the witnesses here today that that is a problem in solving this entire West Coast energy crisis. RTO West's current proposed transmission expansion system is based on individual market participants reacting to high congestion prices sent at over 40 congested points on the transmission system.

Included with my testimony is this map. The yellow highlights the potential constraints on the system. Relying on expansion of the grid by individual market participants is fundamentally flawed. If implemented, it is unlikely to provide the free flowing highway system that is needed to facilitate a robust power market, the ultimate goal of any RTO. Given the current failure of market forces to provide adequate generation in California we cannot risk leaving expansion of regional transmission grid to individual market participants when the very conditions necessary for a competitive market do not exist in the monopoly transmission system, and my testimony gives a more detailed explanation of this.

Gentlemen, consumers expect utilities to plan and take action to meet growing demands. They expect the lights to stay on and they expect reasonable prices. To create an RTO without the responsibility and authority to anticipate and take action to meet transmission demands would be viewed as a breach of the public trust. Because Bonneville, a Federal agency, owns 80 percent of the transmission system in the Pacific Northwest, defining Bonneville's role is critical to RTO West. Specifically, Bonneville must insure three things: 1) That the RTO system is able to anticipate the needs of the transmission system in order to facilitate the power market; 2) that the costs and risks of current operation and future expansion not be shifted onto small and rural electric utilities; and, 3) that the RTO system of congestion management and expansion not increase or contribute to the volatility of an already chaotic power market. The answer is to give RTOs the responsibility and authority to plan and expand the system in a timely manner and spread these costs broadly to the users of the system instead of relying on individual participant responses.

Briefly, why will the currently proposed RTO West system not work? It requires users to experience high prices for long periods of time. Expansion of system then takes 5 to 7 years due to planning, permit, construction and rating. Simply put, a user-based system will not respond in a timely manner. Our idea is to give RTO West more authority for planning and expansion of the grid. I want to be clear that this proposal still relies on giving investors who offer long-term solutions to the RTO a fair return on their transmission projects or alternate projects. In this way we are still relying on the market for expansion.

I would like to leave you with one closing thought. Rome was not built in a day nor will a Westwide RTO come into being overnight. FERC acknowledged in its order yesterday that RTO West is the anchor for the ultimate Westwide RTO. Let's not frustrate our purpose by trying to get to a Westwide RTO too quickly. I encourage you to investigate the RTO effort further.

[The prepared statement of Ms. Scott follows:]

Statement of Aleka Scott, Transmission Manager, PNGC Power, Portland, Oregon

Mr. Chairman,

Thank you for this opportunity to testify today. My name is Aleka Scott and I serve as the Transmission Manager for PNGC Power. The issues being discussed at today's hearing are very much on the minds of Northwest electric utilities and their customers. We very much appreciate the opportunity to share our views.

PNGC Power is a Portland, Oregon based electric services cooperative owned by 15 electric distribution cooperatives serving customers in 7 Western states. Our role is to aggregate the loads of those systems, establishing and managing wholesale power arrangements to meet their needs. Our members are all in rural areas and, as such, depend on the transmission systems of the Bonneville Power Administration (BPA), Northwest investor-owned utilities and some select public power systems for the delivery of wholesale power. I have attached a service territory map indicating the areas served by our member/owner utilities.

PNGC Power has been a strong supporter of the establishment of a Regional Transmission Organization (RTO). We continue to believe that a properly structured RTO could deliver great efficiency and reliability benefits to the Northwest region. Such an organization could provide affordable access to the wholesale power market by all wholesale utility buyers, not just those fortunate to be connected directly to the BPA grid, or to high voltage sections of other transmission providers' transmission systems. Any RTO established in the Pacific Northwest must include the transmission assets necessary to ensure transmission access to these utilities. Without inclusion of all the necessary facilities, including those of the Bonneville Power Administration the possibility of market power and vertically pancaked rates continues to exist.

Unfortunately, as I will describe, we continue to have doubts that the outcome of current regional RTO efforts—called "RTO West" will establish more efficient, less costly service to electric consumers. We are actively involved in the RTO development process with the hope that we can alter its provisions to the better.

Background on RTO Efforts in the Pacific Northwest

RTO West is not a west-wide entity but rather includes only the states of Washington, Oregon, Idaho, Montana, Nevada and Utah. For reasons stated further below, we believe it is inappropriate to include California in our RTO.

The goal of regional stakeholders—including PNGC Power—involved in the RTO–West process is to file a plan with the Federal Energy Regulatory Commission (FERC) that meets the needs of both transmission-owning utilities and transmission dependent ones. While it is the responsibility of FERC-jurisdictional utilities in our region to ultimately make that filing, they will not solely determine whether it is successful. The Bonneville Power Administration owns about 80 percent of the transmission assets in the Pacific Northwest region. BPA's assets connect the region from north to south and, without them, there effectively is no RTO West.

As a federal agency, BPA has to look to Congress for direction and oversight on matters as consequential as whether to participate in RTO West. We are encouraged that the Subcommittee has included this subject at today's hearing because, in providing that direction, it is critical that you hear from those of us that will be affected by BPA's decision. As preference customers of BPA, our members cannot favor an RTO which produces a less reliable transmission system or one that imposes far more costs and risk on individual users of that system. We encourage you to continue to exercise your oversight responsibility to determine whether BPA's participation will ultimately be to the benefit of actual consumers.

Why RTOs? Why now? RTOs are FERC's next step along the restructuring road to produce robust, fully functioning power markets. Transmission, a monopoly service, is the transportation piece of this electric commodity market and has in the past been used as a strategic asset to block, limit, or collect monopoly rents from power sales. Transmission owners were able to price transmission well over its cost-basis, effectively taking a "piece" of the power sales transaction. Often this was a disproportionately large piece.

The Energy Policy Act of 1992 gave FERC new authority to order transmission service and FERC responded with the issuance of Orders No. 888 and 889. Transmission was to be open to all at the same terms and conditions that transmission owners made transmission available to their own merchant functions. Separating the transmission arm of utilities from the merchant (generation) arm of the same utility was required. However, abuses continued and FERC issued Order No. 2000 calling for the voluntary (or all but mandatory) formation of RTOs. The idea was to form large, independently operated transmission grids, which would enable the free flow of power within a region without pancaked rates or opportunistically exercised transmission market power.

In the Pacific Northwest, incumbent transmission owners and stakeholders have been working on restructuring the transmission system for over 5 years. Previous efforts, while they have not come to fruition, have laid the groundwork and advanced the level and depth of discussion regarding regional transmission organizations.

Currently, transmission owners in the states of Oregon, Washington, Idaho, Montana, Utah, and Nevada, have formed themselves into a group called the Filing Utilities and are working to form RTO West. RTO West would encompass most of the transmission in these western states. RTO West has a sounding board, called the Regional Representatives Group (RRG), made up of 24 members of "stakeholder" groups such as cooperatives, other public power systems, power marketers, independent power producers, conservation organizations, state representatives, as well as representatives from the Canadian provinces of British Columbia and Alberta. Working underneath the RRG are technical work groups that are open to any interested party. The decision process calls for consensus items to be preserved in the filing, with the Filing Utilities deciding on matters where consensus does not exist. Ultimately, because of the diversity of opinion, it is the Filing Utilities who will decide the bulk of what is included in any RTO West filing to FERC.

RTO West made a Stage 1 filing to FERC in October of 2000 and asked at that time for an expedited ruling. At this writing, FERC is expected to issue an order on the RTO West Stage I filing in the next few days, which means the clock continues to tick and final decisions about the structure and composition of the RTO must be completed shortly. The Filing Utilities and other involved parties have continued to work on Stage 2 of the RTO West development. Issues which remain open include congestion management, development of a tariff, how the transmission grid will be expanded, development of the scheduling coordinator role, the translation of existing contracts into rights and dollars in the RTO West world, as well as how unconverted contracts will operate. There are many, many policy and technical issues still to be resolved.

Congested Transmission System

In the geographic area covered by RTO West we face an ever more congested transmission system. Why is this system, which only 5 or 6 years ago had minimum congestion, now so congested? There are four reasons. First, loads have continued to grow steadily. Secondly, because of the uncertainty surrounding recovery of transmission investment, very little new transmission investment has been made in that timeframe. Thirdly, the system is being used in ways it was not designed for in order to accommodate more and more market activity. And lastly, the outages of August 1996 triggered the study of simultaneous operation of many paths which had not previously been studied together. These studies have often resulted in lower operating limits on existing lines than prior to those outages.

Transmission Expansion

BPA's transmission system is now more constrained than at any time in its history. Other transmission systems in the RTO West area also have more transmission requests than transmission capacity. If RTO West does not have adequate expansion authority, we believe that the reliability of the system will be placed in jeopardy. Reliance on individual users receiving market-based congestion pricing signals for transmission expansion across congested flowpaths is misguided, and for the reasons explained below, expansion is not likely to occur. If this type of expansion mechanism is implemented by RTO West, it is likely to have the effect of creating multiple load islands—in effect, islands of market power due to unrelieved constrained transmission capacity. The result of this market failure will be extremely high and volatile prices for transmission rights across flowpaths and into load islands.

Instead, the RTO needs to have the authority to plan and expand the transmission system. It is essential that the RTO put in place a mechanism that actually encourages the relief of constraint points instead on institutionalizing them. The underlying worldview here is that congestion is "bad". Congestion constrains trade and results in less efficient use of resources. In an ideal world, there would be no congestion and power markets would flow freely. We need to bear in mind that an RTO is supposed to be the antidote to transmission market power, the antidote which allows for the most robust power market. To establish an RTO that monetizes the value of congestion but does not put a workable method in place to relieve congestion simply creates more market power and, more ability to make excessive profits. Ultimately, consumers lose.

There are many reasons why a user-based market-driven expansion program is unlikely to succeed. Foremost of these reasons is that the transmission system is a single unified machine that essentially is a monopoly. No transmission system can meet the requirements needed for a user-based market expansion to work. For this type of expansion to work, transmission expansion would have to meet the requirements of a competitive market. The requirements for a competitive market are a) low barriers to entry, b) many buyers and sellers, c) ready access to market information, and d) that no single buyer or seller can make the market. None of these conditions are met in the transmission expansion arena as discussed below.

a) The first requirement of a competitive market is low barriers to entry. Transmission expansion has enormous barriers to entry. Transmission expansion projects tend to occur in large size increments, often more than any one user or even groups of users can utilize in the near-term. For example, if a party needs an additional 100 MW, the expansion available is likely to be a 500 MW expansion. Transmission expansion is dictated by the physics of electricity, not the additional capacity needed by a market participant. These transmission additions are long-term, capital intensive assets. Typically they have service lives of 40–50 years. Few market entrants, if any, have 40–50 year investment paybacks and fewer still have access to the capital necessary to build transmission. Another barrier to entry is the complexity involved in building transmission, from siting right-of-way to permitting to actual design and overseeing the construction. Five to seven years is the industry standard lead-time for building transmission additions. This kind of lead-time in itself is a barrier to entry for many, many potential participants, in an industry where companies can be wiped out by just a few bad trades.

Substitutes for transmission expansion can be strategically placed generation or demand-side programs on a scale large enough to forego transmission additions. These substitutes are also not "low barrier to entry" activities but certainly have a role as alternatives to transmission. However, we believe these substitutes have a limited role and will never fully supplant transmission construction. Further, the signals for these transmission expansion substitutes are, on the whole, better implemented by an RTO in the form of incentives rather than through a complex, cumbersome, and highly volatile congestion-pricing scheme.

b) "Many buyers and sellers" simply does not describe the transmission system. Transmission has always been a monopoly, or at best, oligopoly business. RTO West is no exception. In addition, as currently proposed in Stage 1 RTO documents, each of the existing transmission owners will still retain a first right of refusal to build transmission additions, perhaps at any price. Some will argue that there are substitutes for transmission such as generation or demand-side programs. While these measures may be transmission substitutes in some cases, they are certainly not the universal substitute for transmission that some would portray them as. Often, the only answer to a transmission problem is a transmission addition. If an area is constrained by transmission limitations, by definition the access of many buyers and sellers is limited. In such a constrained transmission area, a generator or a holder of firm transmission rights can exercise market power. Thus the second part of our test for the existence of a competitive transmission market—many buyers and sellers—fails.

c) A competitive market requires good access to market information. The role of RTO West is still unclear in this area. Some argue for the RTO to have full planning capabilities while others argue that the RTO's role should be confined to simply identifying problems but leaving the fixes to the "market". The market however will not receive the price signal that a path is congested until it actually is congested. This signal, high prices, will have to be experienced for a reasonable duration in order for parties to be motivated to fix the congestion. At this point however, it is too late. Transmission construction takes 5 to 7 years given the complex design, permitting, procurement, and construction involved. The proposed RTO West market-driven expansion system implies that the transmission customers will have to feel the pain of the high market price for 6 to 9 years before it is relieved. Judging from the unwillingness of nearby jurisdictions to allow price signals to reach the consumer level and the long lead times involved in transmission planning and construction, it is unclear that a market-driven expansion system will deliver the best value for consumers. Instead, RTO West should be vested with the clear ability and authority to plan and expand the system in a timely manner to avoid the kind of catastrophic shortages now being experienced in California.

d) Lastly, in a competitive market no one party can make the market. If a private party does expand a transmission flowpath and receives all of the physical rights associated with the expansion, they become the market maker on that path.

We are highly skeptical that user-based market-driven expansion will work; rather, we need to build an RTO that can assure the region a robust and reliable transmission system. Persistent transmission constraints, even those caused by commercial congestion, can endanger reliability and prevent development of a fully competitive power market. The RTO must have the authority to compel the transmission owners to construct or to allow third parties to build transmission additions, and to allocate the costs to the appropriate transmission owner or owners in a timely manner.

Aside from planning and expansion issues, there are other equally critical issues.

Facilities Inclusion

In the Pacific Northwest, , there are over 100 public and cooperative electric utilities serving a diversity of residential, commercial and industrial loads. Each of these utilities is a wholesale power customer. Not all of the transmission facilities needed to reach wholesale power customers are included in RTO West. The lack of inclusion of secondary transmission between the RTO West transmission system and many wholesale utilities' points of delivery potentially subjects utilities to vertically pancaked rates, double or triple the regulatory burden, and multiple planning and expansion forums required to ensure reliable service. The net result could be a large increase in transmission costs for utilities that are faced with a gap between their wholesale point of delivery and the proposed RTO West system.

Because RTO West may not include all the transmission facilities required to reach wholesale utilities, RTO West will not be able to ensure the reliability of the entire transmission system needed for load service. One goal of an RTO should be to consolidate transmission forums and allow transmission to be easily accessible in a one-stop shop type of organization. Proliferation of the number of forums that address transmission issues, due to exclusion of some transmission facilities, is completely contrary to the intent of an RTO.

Complexity

If the RTO West system was reasonably free-flowing and had 3 or 4 congestion points, the RTO West model for congestion management might work well. FERC acknowledged in its Order 2000 that "while the approach of trading physical transmission rights in a secondary market may prove to be workable in regions where congestion is minor or infrequent, in other regions where congestion is more of a chronic problem, it may not be workable.” [Docket No. RM99–2–000, Order No. 2000, pg. 383] The market driven expansion mechanism relies on price signals being sent over each flowpath. A flowpath is a line or set of lines across which there is commercially significant congestion, also referred to as a constrained or congested path. Because of the large number of potential flowpaths in the RTO West system (see attached map), the congestion management system is likely to result in an extremely burdensome administrative system for scheduling, billing, and procuring transmission while not providing adequate incentive for transmission construction.

Because the user-based market-driven mechanism relies on price signals across flowpaths, the information and flow-based infrastructure required not only by RTO West, but also by all the parties who must interact with RTO West, will be significant. If a user-based market-driven mechanism is to be used for expansion, a significant number of transmission planners will be needed to make the model work. Some things money cannot buy, and at the moment, transmission planners are on that list. In short, the investment needed in infrastructure and personnel appears to be large compared with the benefit of a user-based market-driven expansion system, which seems dubious at best.

Translation of Existing Rights

As contracts are converted from their current form into the flow-based RTO world, we must ensure that existing transmission rights to serve loads are preserved, including any provisions for load growth and peaking. Most BPA preference customers have Network Integration contracts with BPA that require the agency to serve the transmission requirements of the customer, including load growth and any peaking requirements for which these customers pay a “transmission load shaping” charge.

In the RTO world, the initial allocation of rights will be limited to a historic period using a “feasible dispatch” of generation. Firm transmission rights for load growth will be allocated one year at a time, subject to available transmission capacity. However, this could well leave any individual utility customer short on firm transmission rights during an extreme weather event, due to heavy loading of the transmission system from exports, or due to a generation dispatch different from the feasible dispatch used to allocate rights. The result on the load-serving utilities will be either extraordinary prices for firm transmission rights or load curtailment. In this way, the RTO model moves risk from the BPA transmission business to its individual customers without providing compensating value.

RTO West Model Disproportionately Impacts BPA Customers

BPA’s customers are in a unique and unfortunate position. Each IOU will receive physical rights (firm transmission rights or FTRs) on the transmission system to serve its native load. The IOUs will be able to take advantage of the diversity inherent in a large block of load and continue to serve the transmission needs of their native load much as before. BPA, however, has no native load. Instead, it has over 100 separate wholesale customers: corporate or governmental subdivisions called wholesale utilities. If these customers want to convert to RTO West service, physical rights will be assigned to them based on their load. The inherent diversity of loads that BPA captures through the current system to meet all of its customers needs will be lost. It is not gained by any other party; it is lost to the region as a whole due to the RTO West model. BPA’s former transmission customers, many of whom are small utilities, will assume a level of financial and operational risk that was previously managed in the aggregate by BPA. In this case, the sum of the parts is greater than the whole because of load diversity; and it is those parts which bear the additional costs.

This effect is inherent in any congestions model which requires numerous flow paths. Moving towards a model which internalizes many of the constraints and gives the RTO the positive responsibility and authority to relieve the congestion long-term using market-driven expansion, as well as the tools to clear congestion in the short-term, is an option which works. It requires the willingness of the current transmission owners to give real authority to the RTO. PNGC is advancing just such a proposal at the current time.

Conclusion

There are some serious flaws in the RTO West model at present. We at PNGC are working to make the RTO West model more workable, not just for PNGC’s cooperative members, but for the whole region. As part of those efforts, we have proposed an alternative congestion management model which has few zones, allows the RTO West to recapture the diversity of the system, and actively relieves congestion long-term. It is critical that our region stay open to these types of solutions. It is not an understatement to say that the transmission system is the underpinning of our regional economy. The transmission system is what allows for a free-flowing, robust wholesale power market.

RTO West has 12 work groups, each of which is vitally important to the proper functioning of the transmission grid. RTO West is creating out of whole cloth an entirely new way for the transmission system to operate. We need to take the time necessary to be sure that this restructuring is thoroughly thought through and carefully implemented. The possibility for adverse unintended consequences is huge, as the California experience has shown us. We are still hopeful that reasonable solutions to the above problems can be crafted. However, at this point, we can not say if the RTO West final proposal will meet the needs of the region or not. We urge the Congressional delegation to learn about these very complex issues and to take an active interest in RTO West in order to safeguard the reliable delivery of our region's most vital product, electricity.

As stated above, we believe that the RTO West proposal will live or die based on the BPA's participation. At present, we are not prepared to support that participation until we have more comfort that BPA's utility customers will be able to operate in the new environment in a way that is efficient and cost-effective. This is a critical point that we believe warrants further Congressional oversight. BPA should not participate in RTO West without the support of its customers and of Congress.

We believe that BPA and the IOUs need to begin transmission improvement programs now and should not abdicate this responsibility to the so-called user-based market-driven mechanism. In the Northwest, BPA owns about 80 percent of the transmission assets. It is essential that the IOUs be willing to step up to the plate and share in the costs of BPA's transmission expansion program, recognizing that a free flowing power system within the Northwest benefits the entire Northwest economy. Compared to the cost of power today, these improvements are relatively minor in the overall cost of delivered power. As a region we cannot wait for RTO West to be established and then hope that the user-based market-driven expansion will work.

Let me leave you with a parting thought—No West–Wide RTO. At the meeting which the FERC held in Boise on April 10, 2001, the Commissioners heard from representatives of 11 states. There was broad recognition at that forum that it was impractical at this time to institute a west-wide RTO—adding California and other areas to those already contemplated in RTO West. Each region has a unique history and topology concerning transmission. Forming regional transmission organizations has involved incredible levels of effort and compromise and we, as a region, are not there yet. Each region must take the first step of forming regional RTOs with recognition of the issues at the RTO interfaces (so-called seams issues). Eventually, either adequate treatment at the RTO seams or a west-wide RTO will evolve to truly unify the western interconnection.

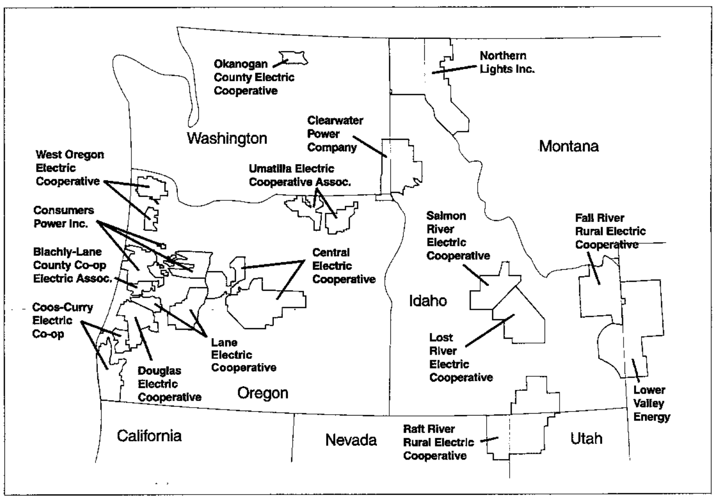
At the moment, California has its own crisis with which to deal. To force other regions with their own traditions and practices to come together with California at this time is a recipe for revolt and disaster. Certainly, BPA's customers would not stand for BPA throwing its Federal Columbia River Transmission System in with California until some kind of equilibrium and balance is reached in California.

Again, thank you for this opportunity to testify. I would be happy to respond to any questions you may have.

[Attachments to Ms. Scott's statement follow:]

PNGC Power
Smart. Local. Connected.

PNGC Power's Members and Buying Group Participants



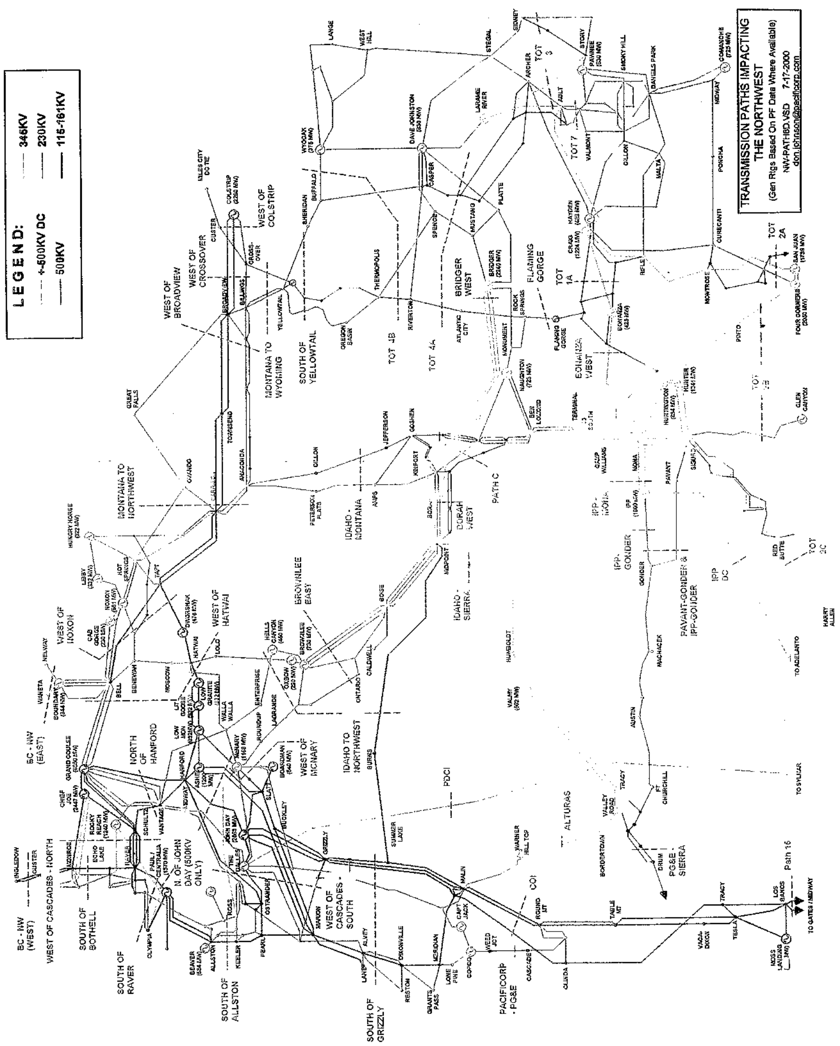
PNGC Member/Owner Systems:

Blachly-Lane Electric Co-op, Eugene, OR
Central Electric Cooperative, Redmond, OR
Clearwater Power Company, Lewiston ID
Consumers Power Inc., Philomath, OR
Coos-Curry Electric Co-op, Port Orford, OR
Douglas Electric Co-op, Roseburg, OR
Fall River Rural Electric Co-op, Ashton, ID
Lane Electric Co-op, Eugene, OR
Lost River Electric Co-op, Mackay, ID
Northern Lights Inc., Sandpoint, ID
Okanogan County Electric Co-op, Winthrop, WA
Raft River Rural Electric Co-op, Malta, ID
Salmon River Electric Cooperative, Challis, ID
Umatilla Electric Co-op, Hermiston, OR
West Oregon Electric Co-op, Vernonia, OR

Additional PNGC Buying Group Participant:

Lower Valley Energy, Afton, WY

Pacific Northwest Generating Cooperative, located in Portland, Oregon, is a member-owned power-marketing cooperative providing power management and technical services to Northwest utility systems and other clients.


LEGEND:
+-500KV DC
500KV
345KV
230KV
115-161KV
TRANSMISSION PATHS IMPACTING THE NORTHWEST
(Gen Rtgs Based On PF Data Where Available)
NW-PATHBD.VSD 7-17-2000
don.johnson@pacificorp.com

Mr. CALVERT. I thank the gentlelady. Lastly, Mr. Richard Erickson, you may begin your testimony.

STATEMENT OF RICHARD ERICKSON, SECRETARY/GENERAL MANAGER, EAST COLUMBIA BASIN IRRIGATION DISTRICT

Mr. ERICKSON. Good afternoon, Mr. Chairman and members of the Subcommittee. My name is Richard Erickson. I am the manager of the East Columbia Basin Irrigation District. I would like to thank you for the invitation to provide information about Bonneville Power Administration's voluntary energy load reduction program on the Columbia Basin Project. The Columbia Basin Project was constructed by the Bureau of Reclamation and is now primarily operated by the East, Quincy and South Columbia Basin Irrigation Districts and provides irrigation water to approximately 640,000 acres.

The first inkling of this energy program came on a January 31 phone call from Bonneville, asking if there would be any possibility to make operational changes to bring about reduced diversions from the Columbia River for the 2001 irrigation season. BPA's purpose was to develop strategies to respond to the developing energy and drought emergencies. The districts were unable to offer much in the way of an encouraging response because the project's canals are operated in direct response to the irrigation delivery orders placed by individual farmers. In other words, we only put into the canals what the farmers order. Any operational tweaking would be truly minuscule in terms of Columbia River flows. The only way to reduce diversions would be to reduce water use by individual farmers and since the project is already quite efficient both in terms of on farm use and operationally, such a reduction could only come about by idling acres.

Shortly thereafter Bonneville asked the three districts' boards of directors to authorize discussions to attempt to develop a voluntary land fallowing program for the project for this summer. Prior to responding to this overture, the three boards directed their attorneys and management to research any potential adverse impacts of such a program to the balance and interrelationships of project reservoirs and canals, to project water rights, to project repayment contracts between Reclamation and the districts, and also possible inadvertent economic or social impacts to others. Based on generally positive results to this research, the three boards authorized negotiations, which began in earnest on February 14.

To understand the complexities of these negotiations requires some discussion of plumbing. Irrigation water for the project is pumped at Grand Coulee Dam into Banks Lake, which normally has a lift of about 280 feet. Because of the drought that lift is now about 370 feet. The energy for that pumping lift is generated by other water falling through the turbines at Grand Coulee. That falling water then is also used for generation at Chief Joseph Dam and nine other dams downstream. An acre-foot not pumped and then becoming available to generate at Grand Coulee and Chief Joseph is equivalent to about one megawatt-hour, not to mention the potential at the nine lower dams. In normal times the wholesale value of that megawatt-hour is $20 or less. This year that wholesale value at times has ranged between $200 and $700. Each irrigated acre on the project uses 3 to 4 acre-feet, equivalent to 3 or 4 megawatt-hours. Until recently the crops grown by that irrigation exceeded $1,000 per acre in average annual value, but that is not true now, this year or in the past few years. Through the course of these negotiations those numbers caused Bonneville to offer project irrigators $330 per acre to not irrigate. That is equivalent to $80 to $110 per megawatt-hour.

To further complicate these negotiations you have to understand that the project's system is designed for the return flows and spills from the upper two-thirds to supply the lower two-thirds. Plus, the project canal system is the site of several small hydroelectric plants having established power purchase contracts with Seattle City Light, Tacoma Public Utilities, and Grant County PUD. In view of current wholesale energy prices, these contracts could not be shorted.

The program was opened for applications by irrigators on March 19th. To bring this about, we had to develop contracts for the districts to administer their program, contracts between the individuals irrigators and Bonneville, letters of consent between Reclamation and Bonneville, plus agreements between the three canal system hydropower purchasers and Bonneville. Also eligibility criteria were developed to attempt to assure that participating acres would yield the energy benefit being sought by Bonneville and to enable monitoring of irrigators for contract compliance to be done in a reasonable fashion.

All this was done knowing that February and March is the start of the farming season in the Columbia Basin and being late would assure no participation. The bulk of the applications were received during the last 2 weeks of March and the first week of April. The lateness of this time frame created a lot of anxiety and frustration for farmers. However, in most cases the time required from the initial application to issuance of an approved contract was less than 2 weeks. 670 farmers have contracted with EPA to not irrigate 91,196 acres, or about 15 percent of the project. Those acres should yield something over 300,000 megawatt-hours of electricity this summer.

My districts' board of directors asked me to emphasize two points in conclusion. The first is that this year's unique coincidence of very low crop values and an energy and crop emergency, including very high wholesale energy costs, has created a situation where agriculture and hydropower have been able to help each other. This means some assured income in uncertain times for participating farmers and some degree of lower electric rates for thousands of northwest electric ratepayers.

The second message is that these circumstances need to stay unique and rare. Water transfers from agriculture should not be seen as a substitute for constructing additional generating capacity.

Thank you very much for the opportunity to present this information and I would be happy to answer any questions.

[The prepared statement of Mr. Erickson follows:]

Statement of Richard L. Erickson, Secretary–Manager, East Columbia Basin Irrigation District

Honorable Members of the Subcommittee on Water and Power:

Thank you for the invitation to provide information to the Subcommittee about the opportunities and challenges of Bonneville Power Administration's Voluntary Energy Load Reduction Program on the Columbia Basin Project. The Columbia Basin Project, constructed by the United States Bureau of Reclamation and now primarily operated by the East, Quincy and South Columbia Basin Irrigation Districts presently provides irrigation water to approximately 640,000 acres of farmland. This irrigation is accomplished by diverting, at Grand Coulee Dam, approximately 3% of the Columbia's flow. The Project is authorized by Congress to ultimately irrigate 1,095,000 acres.

The first inkling of this energy load reduction program came in a January 31st phone call from Bonneville to the CBP Irrigation Districts' management asking if there would be any possibility for the Districts to make operational changes to bring about reduced diversions from the Columbia River at Grand Coulee Dam for the 2001 irrigation season. BPA's stated purpose in this inquiry was to develop strategies to respond to the developing energy and drought emergencies in the Pacific Northwest. The Districts were unable to offer much in the way of an encouraging response to this initial BPA request because the CBP's extensive network of reservoirs and canals is operated in direct response to irrigation delivery orders placed by individual farmers. In other words Reclamation and the Districts only put into the canals what the farmers ask for. Any operational tweaking of the system by the Bureau of Reclamation or the Districts would be truly minuscule in terms of Columbia River flows. It was suggested to BPA that the only way to reduce CBP diversions would be to reduce water use by individual farmers. Since the CBP is already very water efficient, both on-farm and operationally, such a reduction could only come about by idling acres. That initial discussion also included a recognition that the present and prolonged downturn in crop values could possibly make the temporary idling of some acres a serious consideration for some farmers.

Shortly thereafter BPA asked the three Districts' Boards of Directors to authorize discussions with BPA and Reclamation to attempt to develop a voluntary CBP land fallowing program that would result in an energy load reduction of irrigation pumping at Grand Coulee Dam plus increased hydropower generation at both Grand Coulee and Chief Joseph Dams. Prior to responding to this overture by BPA the three Boards directed their attorneys and management to research any potential adverse impacts of such a program to the balance and inter-relationships of CBP reservoirs and canals, to CBP water rights, to CBP repayment contracts between Reclamation and the Districts and also possible inadvertent economic or social impacts to others. Among other things this research concluded that USDA's Payment–In–Kind Program in the early 1980's had idled over 70,000 CBP acres thus providing something of a model and that Washington State water laws and CBP's reclamation contracts provided sufficient flexibilities during droughts. Research also estimated that effects on the balance of the irrigation system and effects on others should be dispersed if the idled acres were limited and dispersed. Based on this information the three Boards, in conjunction with their own judgment that the combination of depressed crop values and the developing power emergency presented unique circumstances for irrigation and hydropower interests to work together, authorized negotiations with BPA and Reclamation. Negotiations in earnest began on February 14th.

To understand the value and complexities of these negotiations requires some discussion of Columbia River and Columbia Basin Project plumbing. Irrigation water for the CBP is pumped at Grand Coulee Dam into Banks Lake, a lift of 280 feet normally. The present drought has increased that lift to about 370 feet. The energy for that pumping lift is generated by other water falling through the turbines at Grand Coulee. That falling water then is used for generation at Chief Joseph Dam and 9 other dams further downstream on the Columbia. An acre foot not pumped to the CBP and then also becoming available to generate at Grand Coulee and Chief Joseph Dams is equivalent to about 1 megawatt hour, not to mention the potential at the 9 lower dams. In normal times the wholesale value of that megawatt hour is $20 or less. This year that wholesale value has, at times, ranged between $200 and $700. Each irrigated acre on the CBP uses 3 to 4 acre feet, equivalent to about 3 or 4 megawatt hours. Until recently, the crops grown by that irrigation exceeded $1000 per acre in average annual value. That is not true this year or the past several years. Through the course of negotiations those numbers caused BPA to offer CBP irrigators $330 per acre to not irrigate, equivalent to $80 to $110 per megawatt hour. While well below the $1000 per acre norm, this $330 turned out to be a good alternative for lands slated for lower valued crops this year.

To further complicate negotiations and planning you have to understand that CBP is designed for the return flows and spills from the upper two-thirds of the Project to provide the water supply for the lower one-third meaning the idled acres needed to be dispersed and balanced. Plus, the CBP canal system is the site of 7 small hydroelectric plants owned by the Districts having established power purchase contracts with Seattle City Light, Tacoma Public Utilities and Grant County PUD. In view of current wholesale energy prices, these contracts could not be shorted.

The Voluntary Energy Load Reduction Program was opened for applications by CBP irrigators on March 19th. To bring this about we had to develop contracts for the Districts to administer the program with the irrigators on behalf of BPA, also contracts between the individual irrigators and BPA, letters of consent from Reclamation to BPA plus agreements between the three canal system hydropower purchasers and BPA. Also eligibility criteria were developed to attempt to assure that participating acres would yield the energy benefit being sought by Bonneville and to enable monitoring of irrigators for contract compliance to be done in a reasonable fashion. All this was done knowing that February and March is the start of the farming season in the Columbia Basin and being late would assure no participation. Bringing this from an initial phone call to implementation in 6 weeks, considering it was being done by 2 federal agencies and 3 units of local government plus involving 3 public utilities, especially considering all the legal complexities, was done at light speed in governmental terms. However, we'll probably have to wait until October or later to definitively evaluate if it was done well, both for agriculture and hydropower.

The bulk of the applications were received from interested farmers during the last two weeks of March and first week of April. The lateness of this time frame relative to the beginning of the growing season created lots of anxiety and frustration for farmers. In most cases the time required from the initial application by the farmer at the District offices to issuance of an approved contract by BPA was less than two weeks. All contacting was completed before the end of the fifth week following the March 19th opening of the application process.

About 670 farmers have contracted with BPA to not irrigate about 91,196 acres, or about 15% of the Project. Those 91,196 acres should yield something over 300,000 megawatt hours of electricity that otherwise would probably have to be imported from outside the region at a higher cost to BPA and its ratepayers. The participating acreage is somewhat over the initial planning goal of 75,000 acres and the original contracted goal of 83,888 acres. Also, the acreage did not disperse quite as evenly as originally intended. Neither of those factors is expected to be a major problem for the Project and could only have been better orchestrated with the luxury of more time for both planning and implementation.

The East District's Board of Directors has asked me to emphasize two messages with this testimony. The first is that this year's unique coincidence of very low crop values and an energy and drought emergency, including very high wholesale energy costs, has created a situation where agriculture and hydropower, respective rural and urban interests, have been able to help each other. Meaning some assured income in uncertain times for participating farmers and some degree of lower electric rates for thousands of northwest electric ratepayers. The second message is that these circumstances need to stay unique and rare. Water transfers from agriculture should not be seen as a routine or reliable source of energy or as a substitute for constructing additional generating capacity. In normal times irrigation water should be more valuable for producing food than electricity.

Again, thank you for this opportunity and for your consideration of this testimony.

[Attachments to Mr. Erickson's statement follow:]

WEATHER
Mostly sunny.
High: **64** Low: **36**
— **Forecast, A12**

SONICS FALL HARD AT HOME
Seattle tallies a season-low point total in a 101-73 loss to the San Antonio Spurs. — **SPORTS, B1**

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Raw or cooked, carrots a nutritious in meals and treats. — **GOOD TASTE,**

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BPA's buyback efforts focus on irrigation project

Plan with Columbia Basin Project could leave up to 75,000 acres unused

By Mike Lee
Herald staff writer

The Bonneville Power Administration is working feverishly to finish a last-minute power buyback plan from Columbia Basin Project irrigators that could leave up to 75,000 acres fallow this summer.

Despite limited interest in BPA's earlier buyback plan through utilities, the agency is turning to one of the West's largest irrigation projects to ease the region's power and water crunch.

"Savings from this program could be significant," said a BPA paper issued last week. "Multiple savings ... make this extremely cost-effective for the region."

One tradeoff is uncertainty among farm goods and service providers, which fear sales of seed, fertilizer, fuel and equipment will shrivel if farmers idle large tracts of land.

"There is a critical mass you need to keep or ... the whole ag economy goes down," said state Agriculture Department Director Jim Jesernig, who is concerned the combined effect of farm-reduction programs in coming years will damage the state's infrastructure.

At present, however, the big need is for power.

By reducing irrigation diversions at Grand Coulee Dam, BPA could save a considerable amount of power used to pump irrigation water a few hundred feet up to Banks Lake, from which it flows through 670,000 acres of the Columbia Basin Project.

If that water stays in the Columbia River, it can turn turbines from Grand Coulee to Bonneville — something the Northwest will need desperately this summer.

How much water BPA's plan leaves in the river depends on how many irrigators choose to forego planting in what could be the basin's largest crop buyout program since the early 1980s.

See **Buyback,** Page A2

Buyback: Start of irrigation season looms over plan

Continued from A1

"Any programs that BPA has cannot impact landowners who are not in the program," said Shannon McDaniel, manager of the South Columbia Basin Irrigation District.

Participation will be up to individual growers with irrigation district ditch riders monitoring for compliance. If the basin buyback floats, irrigators would have to enroll quickly to participate, given the start of irrigation season next week in some farm blocks.

"It's almost getting too late," said Dick Erickson, manager of the East Columbia Basin Irrigation District. "Guys are having to make irreversible planting decisions daily right now."

Basin districts, which have been discussing buyout ideas for a month, hope to get a first look at BPA's proposed buyout rate at board meetings today and Thursday.

There's considerable anticipation among irrigators — though that was quelled a bit last week when BPA's offer to buy power through utility districts was at a much lower rate than many farmers expected.

"There is interest in that because of where the farm commodity prices are right now," Erickson said.

The irrigation district plan is likely to offer a per-acre price instead of the megawatt-hour price offered to utilities last week. Everyone seems to agree the big question for irrigators is how much BPA will offer.

"Rough drafts ... are being fine-tuned as we speak, as is the issue of Bonneville attempting to determine a price," BPA official Ron Rodewald said Monday. He said the complex agreement must work for growers, irrigation districts, the Bureau of Reclamation and BPA.

And, McDaniel said, it must work for Seattle, Tacoma and Grant County utilities, which buy power produced by irrigation water as it drains through the Basin project.

"It's a difficult balancing act," said Rodewald, noting his intent to craft a program that can be used in future drought years to avoid what has become a hectic push to beat irrigation season. "I am optimistic that by midweek ... I'll be able to talk in a lot more detail."

There are other issues, however, including the secondary impacts of idling farmland, which is why there's already a cap of 75,000 acres on the infant program, Erickson said.

At the Wilbur Ellis fertilizer company in Warden, area manager Lynn Pittman is watching closely as farmers make decisions and hoping fallow land is dotted throughout the Basin.

"If it's a pretty localized buyout, its going to be devastating for everyone who feeds from the same trough, and there's an awful lot of us," he said.

With the exception of farmers who participate in a buyout plan, Basin districts are expecting to get their full water supply despite drought conditions. Districts, however, will have to do some juggling to get water where they need it given low levels of Lake Roosevelt behind Grand Coulee Dam.

The average annual volume of water diverted from the Columbia by the Basin project is 2.4 million acre-feet, or about of 3 percent of the flow at Grand Coulee.

"We are anticipating irrigation diversions in what our normal range would be," McDaniel said. "Those quantities will likely be met, and so it looks as good as it can get" in a drought year.

■ Reporter Mike Lee can be reached at 582-1542 or via e-mail at mlee@tri-cityherald.com.

Metro/Northwest A3
Tri-City Herald
Wednesday, March 14, 2001

BPA raises water payout offer to farmers

Water broker wants to buy 75,000 acres to keep hydrosystem intact

By Mike Lee and Shirley Wentworth
Herald staff writers

In a dramatic policy change Tuesday afternoon, the Bonneville Power Administration jacked up its payouts for farmers willing to sell their water.

After telling farmers Tuesday morning that their water was worth $265 an acre, the cash-strapped agency called Columbia Basin irrigation districts at the end of the day and offered $330 an acre and other provisions that should appeal to landowners.

The move could prove to be enough to persuade farmers to fallow their land, something that would have been extraordinarily difficult with the first proposal, given that the irrigation season starts Monday.

"That is a good offer," said Pasco farmer Maury Balcom after hearing BPA's revision. "It's something in the realm of what we were looking for."

BPA wants to buy out 75,000 acres to keep water in the Columbia River so it can produce power from Grand Coulee Dam through the federal hydrosystem. Should the program reach capacity, BPA will spend nearly $25 million and idle about 10 percent of the Columbia Basin Project.

"They are going to up the ante," said Shannon McDaniel, manager of the South Columbia Basin Irrigation District. "It's probably going to make a lot of difference."

At board meetings Tuesday, the East and South irrigation districts found plenty wrong with BPA's first offer — for districts who would administer the program and for farmers who could choose to participate.

"It would appear to me like they are not really serious about acquiring water or power," said Bryan Alford, a Pasco farmer and South District board member. "It appears they don't need it that bad."

Even though board members weren't enthusiastic about the program at $265 an acre, they agreed to consider it because farmers have shown substantial interest.

"Some growers ... are really looking to this," said Mark Booker, East District board chairman.

Under BPA's first plan, farmers would have received 10 percent of payments for six months, then a final 40 percent in October — exactly the opposite of what farmers need to be able to pay irrigation assessments, which are due at the start of the season whether or not they use water.

"It's an insult," said Dick Conrad, Franklin County orchardist and South District board member.

"Apparently, BPA didn't listen to anything we had to say," said Balcom, also a South District board member. "We wasted our time."

BPA, however, came back late Tuesday and offered three equal payments — something Balcom said would be much more palatable to farmers who have fixed production costs to meet.

Despite the program's newfound momentum, it's not yet a sure thing.

Conrad, for instance, has several concerns about whether contract language would protect the district. "We shouldn't expose our landowners to any sort of risk we can avoid," he said.

But perhaps the most important remaining issue is getting approval to participate from Seattle, Tacoma and Grant County utilities, which buy power from water that runs through the Columbia Basin Project. They stand to lose between $6 million and $7 million in lost power generation if Columbia River water is not diverted into irrigation canals.

East District manager Dick Erickson said his district won't sign unless BPA is willing to compensate utilities for their losses. "We can't hazard our power purchasers who we have 40-year contracts with for a one-time deal," he said.

Also, there's questions about whether farmers can use water at the very end of the irrigation season to grow cover crops that help prevent soil from blowing off fields. BPA's first offer penalized farmers for that, but it was not clear late Tuesday whether the new payment program made provisions for September watering.

In an attempt to finalize the contract, the East District board meets again at 10 a.m. Monday and the South District plans to meet at 1:30 p.m. Friday.

■ Reporter Mike Lee can be reached at 582-1542 or via e-mail at mlee@tri-cityherald.com.

Basin farmers consider Grant PUD proposal

By the Herald Basin bureau

EPHRATA — While irrigation districts in the Columbia Basin met Tuesday to hash through a Bonneville Power Administration power buyback proposal, about 275 farmers gathered in Ephrata to hear about the Grant County Public Utility District's deal.

The PUD's one-year offer extends not only to farmers, but also to other industrial users of water. Those who enter the program can use only 10 percent of the power they used last year and must sign up by April 10.

There are two options. In the first, the PUD will pay a locked-in price of 8 cents per kilowatt-hour. The PUD also offers a second choice in which program participants can accept payment at the end of the season based on the average of the period's power sales price. In both options, the PUD splits the savings 50-50 with participants. That's after the minimum system charge is taken out of the power bill — usually about 20 percent.

The PUD estimates canal irrigators can make between $50 and $100 per acre, while deep well irrigators should be able to make between $120 and $200 per acre. Canal irrigators also have the option of letting their water stay in the river and be used for power production instead of crops, which could earn them an additional $15 to $45 per acre.

Metro/Northwest A3
Tri-City Herald
Saturday, March 17, 2001

Basin irrigation districts seek pact with BPA

By Shirley Wentworth
Herald Basin bureau

Officials from the East and South Columbia Basin irrigation districts expect to scramble this weekend finishing up power buyout contracts with the Bonneville Power Administration.

The deals will enable the power marketing agency to buy water from farmers willing to take crop acreage out of production.

Friday, boards of both districts approved signing contracts with the BPA. The deals are contingent on the agency's agreement to compensate Seattle, Tacoma and Grant County utilities, which buy power from water that flows through the Columbia Basin Project. The utilities stand to lose between $6 million and $7 million in lost small-scale hydroelectric generation if Columbia River water is not diverted into irrigation canals.

The BPA wants to buy water that would otherwise irrigate 75,000 acres. This extra water would produce additional hydropower through the federal dam system. The BPA would spend about $25 million and idle about 10 percent of the Columbia Basin Project's irrigated farmland if it buys all the water it needs.

The idea is to take 25,000 acres out of each district with the goal of hanging onto about 300,000 acre-feet of water in the Grand Coulee Dam, which South District manager Shannon McDaniel estimated equals about 138 megawatt hours of power.

If the contracts are signed this weekend, land owners can pick up applications for the program Monday at irrigation district offices: 55 Eighth St., Othello, and 1135 E. Hillsboro Road, Pasco. The Quincy Columbia Basin Irrigation District meets Monday to work through its own arrangement with BPA.

Farmers will sign individual contracts with the BPA, and the irrigation districts will sign a separate contract to administer the program, which includes weekly reports from district officials ensuring program participants comply with the agreement.

The program's details were in a state of flux all week, but by late Friday, some contested items had been resolved.

For instance, BPA officials earlier refused to allow farmers to enroll in its program if they choose to enter another program offered by the Grant County Public Utility District. BPA later reversed its position. However, its conditions don't allow participants already enrolled in other federal programs paying to use water or that pay farmers not to grow crops.

"They don't want to pay for something that's already fallow," said Dick Erickson, East District manager.

BPA's first proposal came Tuesday when it offered to pay farmers $265 an acre. However, the agency came back later with a $330-per-acre figure after East District officials told the agency its offer wasn't good enough.

However, the hitch for most farmers will be a condition that penalizes farmers who want to irrigate between Sept. 17 and Oct. 1 to prepare for spring planting. They would be limited in how much water they could use, and their water-for-power payments would be reduced.

"It will be fairly expensive to take the September option to irrigate," Erickson said. "BPA wants it to be expensive. They expect to need a lot of power."

Some farmers consider that the worst part of the deal because of the need to start irrigating in mid-September for spring crops.

"Whoever does it has to look at it as a two-year program," said Dwayne Michel, an Othello farmer. "It's a backlash on the farmer for the next year."

Attorney Richard LeMargie told those attending district meetings in Othello and Pasco on Friday that they need to be farming while waiting for BPA approval because there's no guarantee about who will be selected for the program — or how they will be selected.

South District board member Richard Conrad agreed.

"BPA has the final say," Conrad said. "They can say no because they don't like the way you part your hair." He added that anyone with a question regarding the contract should have their attorney review it.

"It's a first time thing for everybody, so there'll probably be some administrative problems,' LeMargie said, emphasizing BPA's responsibility. "It's like the airline. If there's a problem, don't chew on the ticket person — chew on the airline. In this case, BPA is the airline."

To be eligible for the program, the land must be supplied by Columbia Basin Project surface water from Banks Lake or other project reservoirs fed by Banks Lake.

The BPA will take applications until April 20 unless it reaches the 75,000-acre goal sooner. Applications should take about 15 days to process.

Those who wish to sign up for Grant County PUD's program must do so by April 10. PUD officials estimate canal irrigators can make between $50 and $100 an acre by entering the program and an additional $15 to $45 per acre if water users let their water remain in the river for power production.

Deep well irrigators should be able to make between $120 and $200 per acre.

PUD Manager Don Godard said his utility has sufficient power to meet Grant County's needs this year without raising rates.

However, he said, the program is important to help prepare for next year's power needs.

Those interested in signing up can call 509-766-2504.

■ Reporter Shirley Wentworth can be reached at 509-488-0657 or via e-mail at swentworth@cbnn.net.

3-19-2001 4:20PM FROM GCPHA 509 754 2425 P. 1

TO: J. BAIRD, D. ERICKSON
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COLUMBIA BASIN HERALD 3-19-2001

Irrigators line up in Othello for BPA buyback program

◆ Basin farmers have their own 'March Madness'

By Clyde A. Small II
Herald staff writer

Farmers are notorious for getting up before dawn. This morning was no exception.

In the wee small hours of Monday morning, irrigators who have been waiting for more than three weeks to look over a BPA power buyback contract, started lining up in the dark at the door of the East Columbia Basin Irrigation District main office in Othello to get a copy of the long-awaited document.

When long-time farmer Jay Jenkins went to town this morning to have a look see at the contract himself, he found a line of irrigators several blocks long winding down the sidewalk, waiting to get their hands on the much-anticipated final product.

"A woman at the District said some of them came last night and stayed all night on the sidewalk," Jenkins said. "I was shocked to find no place to even park."

Richard Erickson, secretary-manager of the East Columbia Basin Irrigation District, announced last Friday afternoon the Bonneville Power Administration's approval of the availability of their Voluntary Energy Load Reduction Program for irrigators receiving water from the East District.

The program would pay eligible farmers signing up for the program $330 for each irrigable acre not irrigated during this year's growing season. BPA has contracted with the East District to administer the application process for this program.

"The district has assembled a temporary staff to administer this program for BPA," Erickson said in a press release early Friday afternoon. "These employees will meet with water users interested in participating in the program, review and process their applications, and provide arrangements for submittal to BPA."

According to Erickson, for land to be eligible for the program it must be supplied by Columbia Basin Project surface water that originates from Banks Lake or other Project reservoir fed by surface water from Banks Lake.

Other land eligibility and water delivery criteria will also apply. Actual selection of the participants will be made by BPA, not the District.

It is anticipated — but not assured — that the time from initial application by the water user to the execution of the agreement by BPA will be 15 days or less, according to Erickson.

Applications began to be accepted by the District at 1 p.m. today in the District Board Room located at 55 North Eighth Avenue. Office hours for applications will be Monday through Friday between 1 and 5 p.m.

Please see BPA *on page 3*

BPA: *PUD reviewing contract today*

From front page

Morning hours will be used for District staff to review and process applications.

The BPA agreement with participating farmers includes restrictions about participating in certain USDA programs and participating in certain other electrical load reduction programs. Participants must also agree to compensate any employees laid off as a result of the water user's participation in this program.

The Grant County PUD unveiled their own power buyback program last Tuesday that offers irrigators participating in their plan between $65 to $145 per non-watered acre for canal users and $120 to $200 per acre for deep well irrigators, based on last year's power usage.

Jerry Tate, in the PUD's Moses Lake office, is the contact for irrigators with questions and those needing contracts.

PUD's Gary Garnant said the utility's attorney was reviewing the contract today and that upon approval, it will be available to Basin farmers.

The purpose of the BPA program is to contract with irrigators to forego irrigation through Sept. 30, 2001.

This is intended to result in reduced electrical power load for primary irrigation pumping at Grand Coulee Dam and increased power production at Grand Coulee and Chief Joseph Dams.

The Quincy Columbia Basin Irrigation District board is meeting this afternoon to finalize their agreement with BPA

Tuesday
MARCH 20, 2001 • 50 CENTS

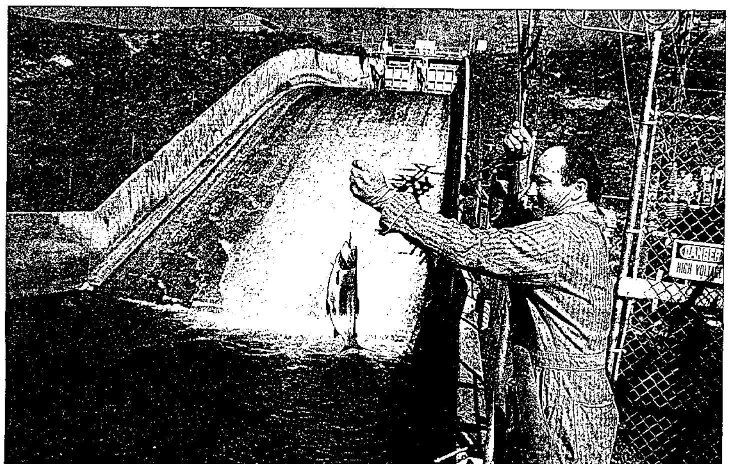
IN LIFE/D1

Power parenting

Trouble with an angry teen?
'Parent Project' can help

THE SPOKESMAN-REVIEW
NEWS ONLINE: WWW.SPOKESMANREVIEW.COM

Precious drops



Colin Mulvany photos/The Spokesman-Review

Worker Jerry LuQue hauls a rainbow trout from the canal at Russell D. Smith Power Plant on Monday after water was released into ditches supplying southern Columbia Basin irrigators.

Floodgates open for irrigators

Some farmers exchange their water for money from BPA

By John Stucke
Staff writer

The water began flowing Monday through irrigation ditches, en route to central Washington's orchards, vineyards and vegetable fields.

These waterways are empty during the winter months. Cracks cover the sunbaked mud channel bottoms.

But the spring growing season has arrived and water is needed.

While the West struggles with an energy crisis and a winter drought that keeps lake watchers nervous, the people in charge of delivering water to farmers calmly turned the valves and flipped the switches, feeding the region's multibillion-dollar agricultural industry.

"We anticipate a normal year here," said Don Olson, speaking loud enough to be heard over water rushing into a canal. As supervisor of field operations for the South Columbia Basin Irrigation District, he ensures that, beginning Monday "If farmers in this district need water, they'll get it."

Mountain snowpack and reservoirs may be low this year, but Olson said he has no worries about the availability of water to grow crops. It will be delivered through concrete-lined canals and smaller ditches that have been scratched into the desert.

Apple, pear and peach trees will get their dose of water. So will grapevines, and fields of potatoes, corn, onions, carrots, asparagus and alfalfa.

Yet vegetable farmers are considering withhold-

Continued: Water/A5

Water flows into a canal in the South Columbia Basin Irrigation District.

Water: BPA ready to pay $24.7 million to farmers for water

Continued from A1

ing water from some fields this summer, weighing low crop prices against a government plan to pay for water conservation and energy.

The Bonneville Power Administration wants to pay farmers for the electricity they use to irrigate fields. The price: $330 an acre.

The offer was so tempting that farmers arrived en masse to irrigation offices to learn more and sign up.

"We had in excess of 100 people interested," said Dick Erickson, who manages the East District of the Columbia Basin Project. "I wasn't sure what to expect, but we had people come here and spend the night in campers."

Basically, BPA is prepared to pay about $24.7 million to farmers to keep 75,000 acres dry.

For many farmers, it's an offer too good to refuse.

Crops have been steady money-losers for several years and the outlook for this year isn't good, said Pasco farmer Ed Schneider. Instead of burying money in the field, the offer should help farmers break even on the acreage enrolled in BPA's buyback program.

The average rental fee for an acre of ground in the Columbia Basin is between $270 and $280 an acre, he said. Add annual irrigation maintenance and delivery fees and the cost per acre to the farmer approaches $330.

Schneider said the buyback offer won't be a windfall for farmers.

Each of the three irrigation districts — the South, East, and Quincy — will be allowed to idle 25,000 acres. Most likely, the acreage left fallow would be for rotation crops such as sweet corn, wheat, beans and alfalfa.

Potatoes, usually the most lucrative crop in the basin, would likely be planted because of earlier contracts with regional french fry processors.

The offer is comparable to the U.S. Department of Agriculture's Payment-In-Kind program, a scheme used to erase crop surpluses by paying farmers not to plant.

Spreading the affected acreage across the basin is expected to help soften the ripple effect to local communities dependent on the crops farmers grow.

To BPA, the $24.7 million may be money well spent as the prospects grow for a worsening energy crisis this summer.

"This is potentially worth 200,000 to 300,000 megawatt hours of generation to BPA," Erickson said. A megawatt hour is enough electricity to meet the power needs of about 600 homes for an hour.

By paying the farmers about $330 an acre, BPA will save power normally used to pump and deliver water. Furthermore, the water that is kept in Lake Roosevelt can be flushed through the power generating dam turbines.

"It's a complicated way for them to get power, but it should work," said Erickson. "And nobody is going to lose their water rights for having done this. Our lawyers have looked at everything very closely."

BPA finds itself in a power predicament because of energy shortages and skyrocketing electricity prices. It has to shop the now-costly open market for energy just to fulfill its supply contracts.

The price for electricity is so extraordinary, Erickson said, that the $330 per acre may be a good deal for BPA. Under BPA's normal wholesale rates, he said, a farmer might fetch $75 to $80 an acre.

The buyback proposal isn't unique.

Idaho farmers are enrolling in a similar type agreement with the Idaho Power Co., and Avista Utilities is drafting its own buyback plan for its Washington and Idaho water pumpers.

Back along the irrigation ditches, Olson said he doesn't pay much attention to the BPA offer.

Instead, he's making sure that his irrigation district is ready for the growing season.

Metro/Northwest A3

Tri-City Herald

Wednesday, March 21, 2001

Basin farmers eager to entertain BPA buyout

Irrigators line up for chance to give up water for $330 per acre

By Shirley Wentworth
Herald Basin bureau

Farmers were lining up at the East Columbia Basin Irrigation District office Sunday like teeny-boppers outside a Ticketmaster outlet.

But instead of tickets to the Backstreet Boys, irrigators were looking for a chance to participate in the Bonneville Power Administration's power buyout program that began Monday.

BPA is offering to pay $330 an acre to farmers in the Columbia Basin Project's three irrigation districts who agree to take crop acreage out of production. Water to be left in the river can be used for power generation to meet expected shortages this summer.

Farmers have been treating the offer like a baseball championship or a rock concert, said East District manager Dick Erickson.

"We did not expect that kind of lineup," he said. "It's chaotic, but we'll get to them."

As it turns out, no one needed to camp out in front of the district's office. About 150 farmers had shown interest by Tuesday, but East Columbia Irrigation is still far from reaching the 25,000 acres sought by BPA from the district, Erickson said.

South District Manager Shannon McDaniel reported his district so far has about 120 farmers seeking appointments to sign up. He said his district isn't even close to approaching its 25,000-acre allotment, either.

A lot of farmers with small parcels are seeking entry into the program, McDaniel said, noting not all will meet BPA criteria.

Quincy District Manager Keith Franklin said his office has been humming since 1 p.m. Tuesday, when it began taking applications.

"It's been fairly busy, but we've not taken count yet," he said.

As the largest irrigation district of the three included in the Columbia Basin Project, BPA agreed Monday to raise Quincy's allotment by an additional 8,888 acres to the initial 25,000 acres.

The Black Sands Irrigation District, which serves about 40,000 irrigated acres, believes it's been unfairly excluded from the BPA offer. The district serves an area around Royal City, Ephrata and Quincy.

But Black Sands uses ground water recaptured from the other three Columbia Basin districts, so BPA can't tell for certain that taking land out of production there will add water to the Columbia River.

However, the district pays the U.S. Bureau of Reclamation the same amount as if its water was delivered by canals, and it should get the same chance at the buyout, said Tom Flint, of the district's board.

"Because of the way we're charged, we feel we should be included," he said. "The Black Sands district feels it's being discriminated against."

The district will likely take legal action against BPA if it does not revise its position, Flint said.

Farmers largely ignored a first BPA power buyout offered through utilities that pay $75 per megawatt.

Franklin County Public Utility District, for instance, had no takers but is still worried about farmers turning off their irrigation pumps.

If the PUD doesn't sell enough power to irrigators, it might have to raise rates to make up the difference.

BPA has said it will help pay for the district's fixed costs, said Franklin County PUD manager Ken Sugden, although there's no formal agreement. "Right now, we're assuming BPA will pay.

"We've been completely out of the loop, and it's been a little frustrating."

■ Reporter Shirley Wentworth can be reached at 509-488-0657 or via e-mail at swentworth@cbnn.net.

Tri-City Herald
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)AY
2001

BPA buy-back helps farmers, may hurt others

■ *With land fallow, service businesses expected to feel pinch*

By Mike Lee
Herald staff writer

The Bonneville Power Administration is taking 15,000 more acres of the Columbia Basin out of production than planned, a move that bodes well for farmers but adds economic uncertainty for farm service businesses.

"It has ramifications through the whole economy," said Bob Cazier, director of marketing for Horizon Ag-Products, which produces humic acid fertilizer in Wallula. "Sooner or later, it will get down to the guy selling pickups ... if it hasn't already."

BPA official Ron Rodewald said Monday that an initial tally of land eligible for the agency's water buy-back program had been increased to 600,000 acres. That boosts the agency's program limit to 90,000 acres from 75,000 acres and ensures virtually all land submitted for the program will be included.

Buying water from the Columbia Basin Project allows BPA to keep it in the Columbia River to generate power at Grand Coulee and other federal dams — power that will be badly needed this summer, given the regionwide drought.

See **BPA,** Page A2

From Page One

TUESDAY

APRIL 17, 2001

WWW.TRI-CITYHERALD.COM

BPA: Fallow land could help push up commodity prices

Continued from A1

"It's a sizable block of water," Rodewald said of the increased volume BPA is buying. "The way this year is shaping up, every bit of water is extremely valuable."

BPA's offer of $330 per acre convinced droves of farmers to take land out of production, a welcome reprieve from the terrible prices many crops are bringing. But 90,000 acres of fallow land creates a huge hole for businesses that sell farm equipment and services. Fuel, machinery, spare parts, fertilizer and irrigation equipment repair companies are among those likely to suffer.

"It looks like it is going to be a major hit for us, but it hasn't happened yet," said Larry Hawley, owner of B&H Ag Chem in Othello. His business gets a double-whammy — he won't get hired to fertilize land that is fallow, and he won't be asked to come back later to apply pesticides.

BPA limited its program to 15 percent of Basin farmland to avoid large-scale disruption of the farm economy. "You don't want to do something that harms the ... whole economic engine east of the Cascades," Rodewald said.

> **"For this (BPA program) to come along, it's really going to hurt. I hope we'll survive, but it's really going to hurt."**
>
> Larry Hawley,
> B&H Ag Chem in Othello

In better times, the limits might have worked. But the situation in farm country is so bad this spring that one report from the state Legislature said a quarter of Washington's farmers had not secured financing for the 2001 growing season.

"We have been taking a major hit here in the last few years because the ag economy is the way it is," Hawley said. "For this (BPA program) to come along, it's really going to hurt. I hope we'll survive, but it's really going to hurt."

At Horizon Ag-Products, Cazier just finished revising the company's annual financial outlook. Instead of seeing a steady 20 percent increase in business as expected, growth is expected to "flat line" as his customers suffer the multiplied impacts of drought, power price increases, BPA buybacks and a poor farm economy.

"The whole situation has created a degree of uneasiness," Cazier said. "Paranoia might be stretching it — but everybody is uneasy, and they are playing it fairly cautiously."

It's not clear how deeply the BPA buy-back will cut into food processors' ability to find product. "We have talked about it," said Dave Klick, executive vice president at the Northwest Food Processors Association. "But I don't think we have enough information yet to see what the big picture is."

The biggest losers probably won't be known for several weeks, when all planting decisions are clear and businesses that cater specifically to the crops that are cut back will start to feel their incomes slip.

Already, it's widely assumed potato plantings will decline substantially from last year's record. Also, reports are that BPA buybacks will include lots of land that produced sugar beets, beans and wheat, crops with minimal profit.

At Saddle Mountain Farm Supply in Othello, owner Bob Parrish realizes the service industry is in for a tight summer, but he takes a positive view.

For starters, he doesn't expect his core business with hay growers to decline much. But besides that, said Parrish, there's a chance that limiting production will buoy some commodity prices.

"There might be a silver lining," he said. "If that will help (farmers) keep their heads above water, I'm all for it. Hopefully, we'll all get through it together."

■ **Reporter Mike Lee can be reached at 582-1542 or via e-mail at mlee@tri-cityherald.com.**

Mr. CALVERT. I thank the gentleman.

Mr. Feider, you mention in your testimony that the actual kilowatt-hours produced by the CVP is not a good match for your customer needs. Why is that?

Mr. FEIDER. As I also mentioned in my testimony, the facilities at the Central Valley Project have outstanding peaking capabilities and they were designed to do that to match the overall needs in the State of California. However, they do not produce the energy that matches the customer load, so that is why it makes sense to purchase firming energy, as Western presently does, from PG&E to maximize those benefits of the project.

Mr. CALVERT. What else can the Bureau do to expand kilowatt production at the CVP?

Mr. FEIDER. As I also mentioned in my testimony, the turbine upgrades that they have underway are certainly moving in the right direction. There are two or three other power plants that are under consideration right now, New Melones Power Plant, Carr Power Plant and Spring Creek Power Plant, that could also improve their efficiency and thus their output could be improved.

Mr. CALVERT. With those efficiencies and add on, what are we talking about?

Mr. FEIDER. They are on the order of 5 or 6 percent in additional generation. Every 1 percent helps in the current situation.

Mr. CALVERT. Do you have a megawatt number that you would be—

Mr. FEIDER. Upgrades at Shasta Dam were about 50 megawatts on the generator portion. The turbine portion that we are looking forward to is about another 50 megawatts. The turbine replacements at the other facilities I mentioned, I am not sure if they will actually increase the capacity. They will mainly increase the energy production.

Mr. CALVERT. Can you explain the coordination with the Federal Government when it comes to turbine and generated replacement and upgrades? How are you coordinating on that? Is it good or bad?

Mr. FEIDER. We have a fairly good working relationship with the Bureau, where we have technical committees representative of our communities such as Redding working with the Bureau's technical people and evaluating proposals and helping run the economics on those. So it has been a fairly well coordinated effort over the last year or two. Prior to that perhaps it wasn't as good as it needed to be.

Mr. CALVERT. Could you please explain steps that could be taken to have win/win, I guess if that is possible, on the Trinity River Record of Decision regarding power.

Mr. FEIDER. On the public process last year the customers of the CVP, particularly the power customers, put forth what we think was a win/win proposal where you would increment parts of improvements to the Trinity River operation in the short term. We support the mechanical restoration of the riverbed by mechanical means. We do not support using water every year to try to maintain that riverbed. We would rather optimize mother nature's gifts when she gives them to us in extreme water years for that purpose. So we would also acknowledge that there may be some need for additional water if the science justifies it for temperature conditions, but for maintaining the riverbed itself we think that is an inappropriate use of a valuable resource.

Mr. CALVERT. Why should the Federal Government be involved? You mention the Path 15 issue when for many of you this is a State problem. And obviously I am from California and we may have a different perspective on that. But I hear that. Do you think the Federal Government has a role in resolving that?

Mr. FEIDER. Yes, I believe the Federal Government has a role. As I mentioned in my testimony, there are some what I consider success stories where the Federal Government was involved in the additions of 500,000 volt transmission lines. The last two additions that were made in California in fact had a role for the Federal Government. And we think that they have existing authorities. We encourage the Department of Energy to utilize those. We are in a situation where PG&E is not able to move forward with construction, and from my perspective in the California crisis whoever can build this project the fastest ought to be building it.

Mr. CALVERT. I am obviously in favor of getting this bottleneck resolved as quickly as possible, but if in fact Federal money is used for designed land acquisition and other activities and putting that together, then I would presume through Western—who should own and manage the transmission line?

Mr. FEIDER. Well, the ownership answer could be worked out over the next year or so and it could be a variety of parties. It could be PG&E ultimately could have the ownership transferred to them. It could be Western. If Western expends Federal funds, we would expect those funds to be repaid through user fees or comparable transmission capacity for optimizing the Federal resource. The Transmission Agency of Northern California, of which Redding is a member, also could be an owner and is trying to facilitate those kind of arrangements as well.

Mr. CALVERT. Now is the design on Path 15 pretty much completed? I mean, as far as land and design, is that pretty much well known as far as being able to acquire that at a—

Mr. FEIDER. The actual status of the design I am not sure I can speak to with a great degree of accuracy. What I can tell you though is that project was identified back in the late 1980's and in fact was certified environmentally in 1988. So there was a preliminary design at that time. The Transmission Agency of Northern California has done some preliminary tower siting and some preliminary design so I would say the design, it is far enough along to begin the land acquisition process, but certainly not to the extent of designing substation termination facilities.

Mr. CALVERT. How long will that take?

Mr. FEIDER. My belief is it can be done in a matter of a few months, perhaps six at the most.

Mr. CALVERT. Mr. DeFazio.

Mr. DEFAZIO. Thank you, Mr. Chairman. Ms. Scott, I think there were some things in your testimony—I am sorry that Mr. Otter left but perhaps I will get him to read the transcript because I want to review a few of these points. I see the map you have provided here and you do have member utilities throughout the Northwest, including Idaho, is that correct?

Ms. SCOTT. Yes, that is correct. There is a membership map also attached to the testimony.

Mr. DEFAZIO. Right, I saw that. We ask obvious questions sometimes. But I look at this map and this is just the Northwest and there is 40 congestion points on this map.

Ms. SCOTT. Yes, I think a few over 40.

Mr. DEFAZIO. As I read your testimony, you are saying 5 to 7 years to basically do major transmission, upgrades in many cases where you have to do siting and things like that?

Ms. SCOTT. That is correct. By the time you go through the whole process of planning, construction, environmental requirements and the rating process, that is what all our transmission engineers tell us, 5 to 7 years.

Mr. DEFAZIO. But let's say even optimistically somehow we can have agreement, because some of these are already existing lines. You already have right-of-way. There are not particularly significant impacts in existing rights-of-way, et cetera, if we were just at the point of probably 2 to 4 years, then we could really speed up the process.

Ms. SCOTT. Yes, I think it is fair to say that it is a whole different set of environmental impacts that you deal with in upgrading transmission lines than, for example, generation. Also there are multi-state jurisdictions on siting, so that tends to slow things down a little bit.

Mr. DEFAZIO. Well, we will leave the years alone. I guess what I am trying to get at here is in reading your testimony I am very disturbed because what it seems to me where we might be headed, and I have raised these concerns with BPA, is if we superimposed a regional transmission organization which does congestion management through a market mechanism, and I guess markets are good for identifying problems and bringing about efficiency but here we have already identified the problems, we already know we are inefficient, what would likely be the impact on transmission prices for your member utilities were we to superimpose a mandate that we have transferable sellable credits and go to a market base mechanism given these 40 congestion points in the Northwest.

Ms. SCOTT. I think Path 15, for example, was a good runner up to this question. We know where the problems are and to a large extent we know how extensive the problem is. If we relied on a user-based—I say user-based because even if the RTO was given the authority, it would use market mechanisms—but the current proposal is to let this fall to individual users and it relies on individual users experiencing high prices for a long time. So to set up—

Mr. DEFAZIO. You mean during these 5 to 7 years the market—every day the market would send me a signal that I was on the wrong side of a transmission path constraint?

Ms. SCOTT. Exactly.

Mr. DEFAZIO. What could I do about it?

Ms. SCOTT. You could pay for it.

Mr. DEFAZIO. I could build generation on my side?

Ms. SCOTT. You could build generation on your side but most of our loads in this area are on the Western, in the Valley area or more to the Western side, and there is a reason why generation isn't there. Generation has a pretty big footprint in terms of air quality, land use, water use and noise. So getting a generator sited is not a slam dunk proposal.

Also, load management is a possibility but again you need to send a signal to consumers to make them willing not to use electricity during critical periods. So alternatives to transmission are available. They are not universally available and as loads grow they become really marginal solutions. Ultimately, you are going to have to fix some of these transmission problems. Especially if Mr. Otter—well especially in the Puget Sound area, for example, and the Portland area, at some point there is only so much load management you can do. And if you cannot get generation in you will have to do a transmission fix. And leaving these to the market is I think going to result in a market failure.

So instead of solving the problem we will continually fracture into more and more congestion zones, which will further disrupt the power markets.

Mr. DEFAZIO. So we kind of have the prospect if FERC rushes to mandating a market based RTO we have the potential for creating very similar problems to what we have in generation. The Californians are getting a market signal every day that they do not have enough generation, although there is a question whether there is enough generation or there is market manipulation. But it takes a while to build the generation. You get the signal every day and you pay every day. So now we are confronted with an even longer term prospect with the transmission, of getting the signal every day, paying every day and waiting until these things gets built.

Ms. SCOTT. That is correct, and I think in some ways we would have many little Californias because as transmission paths—

Mr. DEFAZIO. Now that is a scary thought, Mr. Chairman.

Mr. CALVERT. Oregon is already a little California.

Ms. SCOTT. Because you would basically create little islands of market power where the transmission is completely constrained, and so whoever owned the rights or owned the generation would have an enormous amount of market power and the economic effect of that would be difficult. The currently proposed system tends to shift this risk onto individual utilities where now it is spread over a larger base, either through Bonneville or through the jurisdictional ratemaking of investor-owned utilities. Regardless of where a consumer is in a State, currently we have statewide pricing for consumers. Again, that is a little disconnect on the retail side from what we are proposing on the wholesale side, I think similar to what we had in California where we deregulated the wholesale side but not the retail side.

Mr. DEFAZIO. If I could, Mr. Chairman, I mean as I understood the original theory and I am interested in this and how these theories go awry in application, but it is sort of transmission would become a common carrier. And if I understand that as a way to optimize the efficient use of our generation, move power over longer distances and avoid having to build generation here when you could match into another time zone or into another season and another State, I understand those things, but to get there we would need—and correct me if I am wrong—it seems that your regional transmission organization would need to be either as in the case of what was discussed here earlier, the Federal Government perhaps intervening to remove the congestion of Path 15, perhaps publicly owned or owned by a nonprofit providing, the right-of-way, sort of like our highways are today, for instance, at least in the West where we don't have toll roads. And then, secondly, that this organization seems to me would need to have the authority or capability of either itself building or mandating the building and the upgrading of the systems so we wouldn't have these congestion points. And, third, and this hasn't been mentioned and it wasn't mentioned in your testimony, it seems to me also given what has gone on in California, it would need scheduling authority if it is going to really assure reliability.

Of course that flies in the face of deregulation because you certainly cannot tell someone who owns generation that they should generate to keep the lights on and you will transmit it someplace. But it seems to me if we wanted to optimize the system those are the things we would do.

Ms. SCOTT. I agree with you on the first two points. You know, we are not talking about not using a market base system to do transmission expansion. We are only suggesting that a different party have responsibility for that. So the RTO would use a market system, for example, they would know where the constraints were and they could say, market, I have a problem here, what can you do for me. So people would bid in with either transmission projects, generation projects, demand side or whatever.

Mr. DEFAZIO. But you would not penalize people with higher rates or cutting them up in the interim?

Ms. SCOTT. No.

Mr. DEFAZIO. You would go to the private sector or to the market, whether it is public or private sector, and bid for people to construct and upgrade.

Ms. SCOTT. Right, and by having the RTOs do it we could do it in advance of need instead of waiting until it is a crisis and then having to endure the high prices for 5 to 7 years. So we would still be using a competitive market system but we would be uplifting more of the costs across the system, not necessarily the entire system, perhaps within a zone. As to the scheduling authority, the RTO will have the ability to do transmission scheduling but in terms of scheduling generation that has not been envisioned. If the RTO were to relieve short-term congestion it could use a redispatch system where it would ask for incremental bids and decremental bids to turn generation on or off on either side of a constraint or to get load management on one side of a constraint as a short-term tool.

So again that is a market based system for relieving the congestion short term that I don't think is in —

Mr. DEFAZIO. But sort of in a controlled and regulated and elegantly constructed market system. It is not the Wild West.

If I could, just one other point, Mr. Chairman. I have just read there—I always get my Midwest States mixed up; Wisconsin or Minnesota? Minnesota wants to access power that is now coming from the West because of the deregulation in Montana that Pennsylvania Power & Light, who is now operating all of Montana's generations resources and wants to export to them, they think in

Minnesota they could get cheaper power that way. But in the free market system that is prevailing there their utilities want to build lines not to the West to access cheaper power but lines to Chicago so they can ship their power to Chicago where they think they can make more money. If we depend upon the markets to dictate where and how we put transmission, it does not seem that necessarily we will get solutions that provide low cost power to consumers.

Ms. SCOTT. I think that is right. We forget that the transmission system is a unified machine. And it is not—the conditions for it to operate as a competitive market simply do not exist, and I detail this very thoroughly in my paper. And I think we need to remember RTO West is to optimize the power market but transmission is still a monopoly and as such needs to be operated a little differently.

Mr. DEFAZIO. Thank you, Mr. Chairman, for the extra time.

Mr. CALVERT. I thank the gentleman. Ms. Scott, the five established independent system operators, have they lived up to expectations, in your opinion, in reducing congestion and increasing reliability.

Ms. SCOTT. I guess in California we would have to say no.

Mr. CALVERT. That is what I wanted to hear. How about the other four?

Ms. SCOTT. I am not familiar with their operations, but I do know they came from different backgrounds. In the East they came from a tight power pool background, so they were already operating and dispatching on a much different basis than we operate out here. So I think they have been a little more successful, but again they started from a different place.

Mr. CALVERT. The 40 congestion points you mention in your testimony, is there any common characteristic to those points; are they different in some way?

Ms. SCOTT. Each one obviously is unique, but they all stem from trying to move power from one side to load. Most of the points—you know there is a lot of generation over on the east side, a lot of coal plants, and many of these stem from moving large amounts of coal fired generation in the East, Wyoming and Montana, over to loads in the West. What is common about how these operate is that power, for example, from the Bridger plant, it spreads out and goes over 40 of these congestion paths if you are trying to get a schedule into southern Oregon. So you cannot just say it is here and it is going to go across this way. It actually spreads out all over this system. A schedule from Canada down to California spreads out over about an equal number of paths. Some of the power actually flows around to the East. So what is common is that the power flows that we would be using in this new model is very diverse and if we had to obtain rights on all the paths that we eventually use, it could be an enormous set, thus giving the owner of even a small amount of one of these lesser paths a degree of market power.

Mr. CALVERT. Under the RTO system how would the cost be distributed among the users when building new transmission lines? I guess that is the bottom line on the thing. How would you do that, especially transmission between the two RTOs?

Ms. SCOTT. Which two RTOs? In California?

Mr. CALVERT. And the Pacific Northwest. How would you do that?

Ms. SCOTT. I would tell you how I would like to see it done. The current proposal would have it fall to individual users, but I don't think you are going to find people stepping up for projects that have 5 to 7-lead times and 30 to 50-year lives in an environment where people are requiring very short paybacks and very high hurdle rates. So the way I would have it done is I would have the RTO have very large zones with just a few constraints and within the zones the RTO would fix the congestion. It would then take the cost of that and spread it to the users within a zone. There might have to be a different treatment for through-flows, for flows that are for export, for example.

Mr. CALVERT. And this would apply to maintenance of the system also?

Ms. SCOTT. You know, maintenance of the system is a fixed cost, and that is right now going to be assigned to load. If exports were treated as a load, then they would pick up their fair share. The cost of this expansion would be some kind of ongoing uplift for whatever period you needed to pay it back, but presumably it would be less than the cost of clearing the congestion in the short term. Otherwise you wouldn't fix it.

Mr. CALVERT. Would you—and I apologize if I didn't hear the number—the cost—you mentioned the time line but did you mention a number on that again, the cost of fixing that congestion problem?

Ms. SCOTT. No, I really wouldn't have any idea. Each one—if you relieve some, then perhaps others are impacted. Some are really big numbers and others are probably not, but I couldn't tell you in total. I don't think anybody knows in total.

Mr. CALVERT. I would assume it is a pretty good number.

Ms. SCOTT. I know Bonneville has asked for, I think, an additional $750 million to undertake transmission upgrades on its system alone.

Mr. CALVERT. And this is obviously significantly more than that.

Ms. SCOTT. I think you have to keep in mind 750 million is a big number, but compared to what we have spent on power in the past few months—

Mr. CALVERT. We do that in 2 weeks in California.

Ms. SCOTT. Probably less.

Mr. CALVERT. Are there any technical or regulatory barriers that you need to overcome in order to create this RTO?

Ms. SCOTT. I'm sorry, technical or what?

Mr. CALVERT. Technical and regulatory barriers— you are going to have to jump?

Ms. SCOTT. There are enormous both technical and regulatory barriers.

Mr. CALVERT. How many years did you think that that would take?

Ms. SCOTT. Well, I think that realistically no one is expecting the RTO to be in existence before late 2003. I think that might be a little bit optimistic actually. We have to create an entirely new scheduling center but, more importantly, we have to put in place all the protocols for pricing, planning, operations and congestion management. These things don't exist. This would be brand new, brand new stuff. Regulatorywise, there is an enormous problem, and that is that the States have to approve each of the investor-owned utilities participating in this. So we have not only FERC to get through but also each State.

Mr. CALVERT. In that case, you deal with a Federal judge probably.

Ms. SCOTT. Well, we are hoping not to have to.

Mr. CALVERT. Mr. Erickson, in general, how have many local communities felt about the irrigation load back—or load buyback program? How do they feel about that?

Mr. ERICKSON. I have attached some news articles in my testimony that goes into that somewhat. Generally it was popular with the farmers that wanted to participate just because of the economic times they are in. There was a lot of concern and criticism from some of the farm supply businesses and also early on from some of the food processors about secondary—secondary impacts on them. The food processors were concerned that they would have sufficient acreage to supply their raw product. Obviously fertilizer dealers, irrigation supply dealers were concerned about a loss of business. The perception, though, that I think a lot of them came to was somehow that this money was going to Switzerland.

If you divide the 600 and some farmers that participated into the 90,000 acres, that is like 150 acres per person that participated. So they are all still farming. They just set aside some land. So in effect I think the Bonneville money is giving them some operating money. So I think most of that will still find its way to a lot of the vendors that were concerned. But it was—it was not without controversy, and it was a consideration for our boards before they decided whether to go ahead with it or not. But in the end they felt that in view of the economic times, they could not deny the farmers of that opportunity.

Mr. CALVERT. Besides that buyback program, how has this energy crisis affected agriculture in your area?

Mr. ERICKSON. I think it is expected to affect on onfarm electric costs. The food processors, they are all indicating that they are suffering higher electric costs, which is squeezing them, again, on what they can offer to pay for raw product. So I think it is going to affect rural communities much the way it is the rest of the West.

Mr. CALVERT. Any other questions?

Mr. DEFAZIO. If I could, Mr. Chairman, just back to Ms. Scott. The part of the construct, again, that I am concerned about that I understand that BPA and the other participating utilities have put together is a system of firm transmission rights and then auctioning off—those are fungible, as I understand it, and also auctioning off any other surplus that might exist in the system. And I am concerned about what that might lead to. My understanding is, for instance, I have been unable thus far to get details from BPA on this, that Morgan Stanley—that rate utility has purchased 900 megawatts of transmission in—out of BPA's system or leased 900 megawatts of transmission and is giving the new—the new plant in Klamath Falls a hard time about getting access, because I guess under FERC rules—and you can correct me if I am wrong—they are sort of limited in what they can recoup in terms of profit on controlling the transmission, but they can deny anybody access up until day of purchase short term. They can say—they don't have to sell anybody firm rights; is that correct?

Ms. SCOTT. That is correct. I don't know about the Klamath Falls plant. I do know they have made—I know of at least 600 megawatts that they have requested on the Intertie, and another large amount at the Rathdrum project. I don't know if they are involved with that or not, but they have an enormous request in there. So they have the rights, and until you get into—after the preschedule period, they don't need to release it. So—and the same, incidentally, would be true in the RTO West system. So—

Mr. DEFAZIO. Which would be—

Ms. SCOTT. Which would be if you had the FTR, the firm transmission right, you don't need to release it until—you don't ever need to release it, but the RTO will release it for you if you don't use it at preschedule.

Mr. DEFAZIO. At what point, 1 hour, 1 day?

Ms. SCOTT. Preschedule is usually the day before, and the preschedule period closes out usually 10 o'clock before the active day.

Mr. DEFAZIO. So we could—with firm transmission rights, we could be creating something similar to the California ISO spot market purchase system?

Ms. SCOTT. Yes. I think that would be a little bit different, but it would have the same potential for a kind of chaos.

Mr. DEFAZIO. Thank you, I guess.

Thank you, Mr. Chairman.

Mr. CALVERT. With that, I think I am going to thank the panel, and we appreciate your coming out today and giving your testimony and answering our questions. And this committee is hereby adjourned.

[Whereupon, at 4:35 p.m., the Subcommittee was adjourned.]

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