WAPA ALLOCATION OF HYDROELECTRIC POWER

OVERSIGHT HEARING

BEFORE THE

SUBCOMMITTEE ON
OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON
NATURAL RESOURCES
HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRD CONGRESS

SECOND SESSION

ON

WESTERN AREA POWER ADMINISTRATION POWER ALLOCATION

HEARING HELD IN WASHINGTON, DC
JUNE 16, 1994

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APPENDIX

JUNE 16, 1994

WESTERN AREA POWER ADMINISTRATION POWER ALLOCATION

THURSDAY, JUNE 16, 1994

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS,
COMMITTEE ON NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to call, at 10:00 a.m. in room 1324, Longworth House Office Building, Hon. George Miller (chairman of the subcommittee) presiding.

STATEMENT OF HON. GEORGE MILLER

Mr. MILLER. The Subcommittee on Oversight and Investigations will come to order for the purposes of consideration of a hearing on the Western Area Power Administration. When the chairman gets his act together, we will really get going here.

The purpose of today's hearing is to consider the distribution of 7,000 megawatts of hydroelectric power sold by the Western Area Power Administration. This electricity is generated at Bureau of Reclamation and Corps of Engineers dams in the Colorado, Missouri and California's Central Valley river basins.

The administration is currently reviewing proposals made by WAPA officials to effectively lock in the allocation of this extremely valuable resource for up to the next 40 years. Locking in power allocation could make it impossible for the Federal Government to provide low-cost WAPA electricity for potentially deserving uses, including water pumping related to fish and wildlife restoration, Indian tribes, mass transit and a variety of other purposes.

At a time when water and power systems across the West are being reformed to address new needs, WAPA officials have been rushing headlong in the opposite direction with their effort to lock in the allocation status quo well into the 21st century. In its draft environmental statement WAPA even considers setting allocation policies this year for the Hoover Dam contracts, which will not expire until the year 2017.

The effort to lock in power allocation is not only inconsistent with the general trends in natural resource policy, it is also counter to the past practice at WAPA itself. Since WAPA was created in 1977, the agency has made electricity allocation and contract renewal decisions for individual water and power projects two to five years prior to the expiration of existing contracts and has extended most contracts for 15 years.

The project-by-project method of making allocation decisions offers far more flexibility to meet new environmental and economic needs than the generic lock-in policy proposed by WAPA officials now. It also allows WAPA to tailor allocation policies to meet the vastly different needs of the many regions of the country that WAPA serves. A power allocation policy that works in the Missouri River basin, which is awash in relatively low-cost surplus power, may not work in California where both power demand and prices are high.

I am hopeful that this hearing will provide an opportunity for the administration, WAPA power customers, environmentalists, Indian tribes and others to work together to develop a power allocation policy that serves both the public interest and the particular interests of WAPA customers. It is possible to allocate power in a way that provides WAPA customers with a considerable certainty while retaining the opportunities to meet the rapidly changing needs of the West.

I plan to work closely with all parties to develop an equitable and flexible allocation policy.

[Prepared statement of Mr. Miller follows:]

STATEMENT OF REPRESENTATIVE GEORGE MILLER, CHAIRMAN
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS
COMMITTEE ON NATURAL RESOURCES
hearing on
WESTERN AREA POWER ADMINISTRATION POWER ALLOCATION
June 16, 1994

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Mr. MILLER. Mr. Johnson.

STATEMENT OF HON. TIM JOHNSON

Mr. JOHNSON. Mr. Chairman, several of the witnesses who will be testifying before the subcommittee today are from my home state of South Dakota. I would like to take this time to welcome Mr. Tom Heller, general manager of the Missouri Basin Municipal Power Agency; and Mr. Wilbur Between Lodges, president of the Oglala Sioux tribe.

Mr. Tom Graves of Mid-West Electric Consumers Association also represents many consumer-owned utilities in the upper Great Plains, including South Dakota, and I would like to welcome him before the subcommittee as well.

Mr. Chairman, the topic of Western Area Power Administration proposals to determine the allocation of Federal hydroelectric power is a critically important one for users of electricity in the upper Midwest. I look forward to hearing from the administration and the distinguished panels of witnesses who will come before the committee today.

With WAPA contracts for power from the Pick-Sloan Missouri Basin program set to expire in the year 2000, it is absolutely imperative for those contracts to be renewed as soon as possible. I appreciate your understanding, Mr. Chairman, of the need to have a timely resolution of the question of renewal of WAPA contracts.

Many WAPA customers in the Missouri Basin have been undergoing an extensive effort at conservation activities over the past several years. They have been working with WAPA to implement the integrated resource planning requirements established by Section 114 of the Energy Policy Act of 1992.

By having them appear before the committee today, we will be able to hear firsthand of the efforts and successes that they have had in the many conservation activities they have been undertaking.

I am also looking forward to the testimony of Mr. Between Lodges and congratulate him for his recent election as president of the Oglala Sioux tribe. I will be working closely with Mr. Between Lodges on this and other issues.

Also, Mr. Chairman, on the desks of the Members today is a brochure relative to the E–2000 Energy Efficient Home. I want to congratulate East River Electric and WAPA, Clay-Union Rural Electric in South Dakota, as well as the South Dakota Public Utilities Commission for their work in constructing this home. It is a demonstration of what can be done with existing technology.

[The brochure referred to follows:]

E-2000 Project Sponsors

First Dakota National Bank:

Special thanks to Bank President Ron Johnson and the team at First Dakota for their financial support, expertise and assistance with the E-2000 Home.

South Dakota Public Utilities Commission:

Special thanks to the South Dakota Public Utilities Commission staff and commission for their instrumental support and leadership in developing this project.

Clay-Union Electric:

Special thanks to the cooperative employee group for the creation of the idea and to the dedicated board of directors for their support and vision for the future.

Co-Sponsors

Special thanks for the financial and technical support from:

Western Area Power Administration, Basin Electric Power Cooperative, East River Electric Power Cooperative, the U.S. Department of Energy, and the manufacturers, suppliers and contractors contributing to the project.

Thanks also to Dayton Builders for their quality construction, and their design work for the E-2000 Home.

This brochure was printed on recycled paper using non-toxic inks.

E-2000

"It's not a home of the future, rather a home for the future."

Sponsored By
First Dakota National Bank
South Dakota Public Utilities Commission
Clay-Union Electric Corporation

Your home may well be the largest investment you'll ever make. But biggest doesn't always mean best- especially if your house drains you of energy, patience, and dollars.

The average home has the equivalent of a two-foot opening that leaks energy, day and night. Most homeowners aren't even aware of the problem- they just keep paying for wasted energy.

In an effort to demonstrate solutions to this problem, Clay-Union Electric Corporation developed the idea to build an energy-efficient home, using the most energy-efficient products and technologies available. Teaming up with Clay-Union Electric to build the E-2000 Home are the South Dakota Public Utilities Commission and First Dakota National Bank. Co-sponsors of the project include Western Area Power Administration, Basin Electric Power Cooperative, East River Electric Power Cooperative, the U.S. Department of Energy, and manufacturers and suppliers from South Dakota and across the United States.

The E-2000 Energy Efficient Home is not a science fiction "home of the future," rather a practical, stick-built "home *for* the future." Materials, designs, and practices used in the construction of the home are new, yet they are available for any homeowner, builder, or remodeler today. This is what makes the E-2000 Home a practical and useful energy-efficient tool for everyone.

The E-2000 Energy Efficient Home is the product of a team of organizations, working together to provide information, education, and leadership in energy efficiency as applied to residential construction. Enjoy your tour of the home.

R-value, or resistance value, is a measure of how well a material is insulated. The higher the R-value, the more insulated it is.

The E-2000 Home costs less to operate not only because of the energy-efficient heating and cooling system, but also because of the high R-value of its components.

Listed below is a comparison of the R-value of some of the components of the E-2000 Home, compared to a conventional standard construction home of the same size.

The E-2000 Home and the typical construction home both have a square footage of 1425 on the main floor, with an unfinished basement.

	Typical Home	E-2000 Home
Roof	R-38	R-50
Above-ground Walls	R-18	R-28.5
Basement Walls	R-2	R-20
Windows	R-1.8	R-3.5

Energy Efficient Features

The E-2000 Energy Efficient Home utilizes many concepts and unique products. Highlighted here are a fraction of these energy-efficient features.

Walls ■
Two-by-six inch framing allows for more insulation between studs than conventional construction. The walls of the E-2000 Home have an R-28, made up of 2 pounds of Styrofoam exterior sheathing and CertainTeed Insulsafe III blown fiberglass insulation. The house is constructed with South Dakota lumber from Pope & Talbot Inc.

Insulation ■
Small-fibered blown-in fiberglass ensures 2 pounds of insulation density per square foot. Installed by M&R Distributing, this pure white fiberglass will not settle, and seals cracks and cavities better than batt insulation. In addition to its excellent insulation properties, this fiberglass insulation is fireproof and adds soundproofing.

Windows ■
Double-paned, high-efficiency Andersen windows have a low-emissivity film to absorb solar heat in the winter and reflect solar heat in the summer. The window panes have an insulated frame and are filled with argon gas to prevent heat loss through convection. To provide the home with natural light during the day, the home was built with five Andersen skylights, which add beauty as well as efficiency.

Foundation ■
A Lite-Form foundation system with DOW Styrofoam provides the E-2000 Home with an R-20 insulated basement for maximum energy efficiency.

Compact Fluorescent Lighting ■
Compact fluorescent lighting is used throughout the E-2000 Home. New compact fluorescent lights use the latest technology and have an application for every lighting fixture. In addition to providing significant energy savings, compact fluorescents have a life expectancy of ten years, compared to a few hundred hours of an ordinary incandescent bulb.

Passive Solar Design ■
Solar energy is used to heat the E-2000 Home in two ways. Passive solar heat is stored in the earth; the ground source heat pump extracts this heat, and uses it for the heating and hot water requirements of the home. The E-2000 Home also utilizes solar energy from the home's orientation to the sun— facing directly south, and has many windows facing south to capture natural light and provide passive solar heat.

Indoor Air Quality ■
Every effort has been made to seal the E-2000 House to eliminate air infiltration. Because extensive measures have been taken to prevent air from leaking into the home, air changes in each room must be mechanically instituted to provide for a clean, fresh, and healthy environment. The air is mechanically changed by a Van-EE heat exchanger mounted in the basement. This system also eliminates excess moisture while recovering heat.

Energy Trusses ■
The ceiling trusses of the E-2000 Home have an energy heel, which provides additional space at the eaves to allow the proper depth of insulation. On a conventional home, only three to four inches of insulation can be installed at the eaves, making them an easy target for heat loss.

Ground Source Heat Pump ■
The E-2000 Home uses a ground source heat pump to extract heat from the earth in the winter, and tap cool ground temperatures in the summer. The ground source heat pump system will provide heating, cooling, and most of the home's hot water for less than $400 a year. This variable-speed heat pump system is the most efficient technology available today and will provide safe, clean, comfortable, and reliable conditioning 365 days a year. The ground source heat pump will actually pay for itself through energy savings.

Infiltration Barriers ■
Protection against unwanted air infiltration is achieved through a sealed vapor barrier system at the home's foundation, interior walls, exterior walls, ceiling and basement floor. Shelter Supply provided the vapor barrier material, and Raven Industries provided the Rufco exterior house wrap. A rubber gasket was also installed between the home's foundation and sill to properly seal this common air infiltration area. All windows and door jams were foam-sealed, doors were installed with magnetic weatherstripping, and all ceiling electrical boxes were individually boxed and sealed. All electrical and plumbing extrusions in the wall cavity studs were also individually sealed with caulk— treating every stud cavity in the home as a sealed unit.

Project Participants

Dayton Builders	StarMark Kitchen & Bath
Lite-Form	Delta Faucets
Raven Industries	Phillips Lighting Co.
DOW Styrofoam	Independent Millwork
Pope & Talbot Lumber Co.	Edward Sales
Andersen Window Co.	Building Products Inc.
Norm-Herren Building Supply	CertainTeed Corp.
	Gage Brothers
Fullerton Building Center	Georgia Pacific Corp.
Niagra Conservation	Dakota Cooperative Telephone
Border States Electric Supply	Gorley Pro Audio
Water Heater Innovations	Gold Bond Inc.
Shelter Supply	Overhead Door
Total Energy Systems	Contractors Siding & Tool Company
Art Johnson Plumbing	
Turner Plumbing	Truss Pros
Kalins Indoor Comfort	Winn-Nelson Co.
Florida Heat Pump	Cor-A-Vent
M&R Distributing	Pease Industries
Wolverine Siding	Precision Painting
Tri-State Insulation & Siding	Jordan Millwork
	Rich Chausse Drywall
House of Kitchens	Brunick Furniture

Mr. JOHNSON. I had the opportunity, in fact, to cut the ribbon for this residence in my hometown of Vermillion in the last couple of weeks, a home using readily available technology which nonetheless saves 40 to 60 percent of energy use. I think it is something, particularly for people in the upper Great Plains part of our country, to be aware of. And I think that WAPA and East River and our rural electrics deserve a great deal of credit for their very innovative, proactive effort for energy conservation in this respect.

I am going to have to excuse myself fairly soon in order to get on with the USDA reorganization markup that is going on in the House Agriculture Committee. But nonetheless I appreciate the testimony, and I will be reviewing it very carefully.

So thank you, Mr. Chairman, for providing the committee with an opportunity to hear from the administration and the customers of WAPA on this critically important issue.

Mr. MILLER. Thank you. And thank you for your help with the hearing.

[Prepared statement of Mr. Johnson follows:]

TIM JOHNSON
SOUTH DAKOTA

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STATEMENT OF THE HONORABLE TIM JOHNSON

for hearing by

HOUSE NATURAL RESOURCES SUBCOMMITTEE

ON OVERSIGHT AND INVESTIGATIONS

June 16, 1994

Mr. Chairman, several of the witnesses who will be testifying before the Subcommittee today are from my home state of South Dakota, and I would like to take this time to welcome Mr. Tom Heller, General Manager of Missouri Basin Municipal Power Agency, and Mr. Wilbur Between Lodges, President of the Oglala Sioux Tribe. Mr. Tom Graves of Mid-West Electric Consumers Association also represents many consumer-owned utilities in the upper Great Plains, including South Dakota, and I would like to welcome him before the Subcommittee as well.

Mr. Chairman, the topic of Western Area Power Administration (WAPA) proposals to determine the allocation of federal hydroelectric power is a critically important one for users of electricity in the Upper Midwest, and I look forward to hearing from the Administration and the distinguished panels of witnesses who will come before the Committee today. With WAPA contracts for power from the Pick-Sloan Missouri Basin program set to expire in the year 2000, it is imperative for those contracts to be renewed as soon as possible. I appreciate your understanding, Mr. Chairman, of the need to have a timely resolution of the question of renewal of WAPA contracts.

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I am also looking forward to the testimony of Mr. Between Lodges and congratulate him on his recent election as the President of the Oglala Sioux Tribe. I will be working closely with Mr. Between Lodges on this and other issues.

Thank you, Mr. Chairman, for providing the Committee with an opportunity to hear from the Administration and customers of WAPA on this very important issue.

Mr. MILLER. Mr. Allard.

STATEMENT OF HON. WAYNE ALLARD

Mr. ALLARD. Thank you, Mr. Chairman. I just wanted to welcome the panel members who will be testifying this morning before this committee. Energy is a big issue as far as the area that I represent, the State of Colorado, and I will be looking forward to the testimony.

We are already, I understand, having some energy cost impacts within my State because of the forced release of water down the Grand Canyon. That is being reflected in electrical costs. So the customers in my area, the rural electric associations, are all having problems trying to hold down the electrical cost to their customers.

It has raised considerable concerns as far as my area is concerned. I will be anxious to hear what ideas they have in holding down any additional electric rate increases.

Thank you.

Mr. MILLER. Thank you.

Mr. DeFazio.

STATEMENT OF HON. PETER A. DeFAZIO

Mr. DEFAZIO. Thank you, Mr. Chairman. I see a few folks I am familiar with as we worked on the formulation of Section 114 a few years ago in this same room. We saw it when it was an individual bill in this committee.

I have concerns about what I have read in the background materials, and I will listen with great interest to the response and the testimony. In part because of the Energy Act of 1992 and in part because of other evolution in our society, we are seeing tremendous uncertainties brought into the area of the electric power generators and people who transmit the power.

It is reflected in my own region, the Bonneville Power Administration seems to be on a fast track to making some major commitments about six or seven years ahead of time for the direct service industries, the aluminum companies, and other customers, and I have got to wonder if, on the one hand, we are being told that we have to impose these dramatic efficiencies and we are so worried about cost that, you know, on the other hand, we can provide these sorts of long-term contracts. If there is going to be this much of an unsettling in the industry, if there is going to be this much competition from new IRPs, if there is going to be all this disruption—we all search for certainty in an uncertain world—the question is whether it is ultimately in the best interests of the ratepayers, whether it is in the best interests of the resources that we enter into these sorts of long-term contracts before it becomes more clear what the shape of the playing field is and what game we are playing five and ten years down the road for the industry.

And what I fear is that we may set up situations where we are locked in by contract which are going to be very detrimental to ratepayer interests and environmental interests in terms of a search for a cost-effective renewable power and conservation resources.

So I come here with some skepticism, and will certainly look forward to the testimony, Mr. Chairman.

PANEL CONSISTING OF THOMAS HELLER, GENERAL MANAGER, MISSOURI BASIN MUNICIPAL POWER AGENCY, SIOUX FALLS, SD; CLIFFORD BARRETT, EXECUTIVE DIRECTOR, COLORADO RIVER ENERGY DISTRIBUTORS ASSOCIATION, SALT LAKE CITY, UT; THOMAS P. GRAVES, EXECUTIVE DIRECTOR, MID-WEST ELECTRIC CONSUMERS ASSOCIATION, DENVER, CO; JAMES HENDERSON, PRESIDENT, LOVELAND AREA CUSTOMER ASSOCIATION, LAMAR, CO; JAN SCHORI, GENERAL MANAGER, SACRAMENTO MUNICIPAL UTILITY DISTRICT, SACRAMENTO, CA; AND, THOMAS S. MARTIN, GENERAL MANAGER, ELECTRICAL DISTRICT NO. 2, PINAL COUNTY, AZ

Mr. MILLER. The first panel, I would like to welcome to the committee Mr. Thomas Heller, general manager of the Missouri Basin Municipal Power Agency; Mr. Clifford Barrett, executive director of the Colorado River Energy Distributors; Mr. Thomas Graves, executive director of the Midwest Electric Consumers Association; Mr. James Henderson, who is the president of the Loveland Area Customer Association; Ms. Jan Schori, general manager of the Sacramento Municipal Utility District; and Mr. Thomas Martin, general manager, Electrical District No. 2, Pinal County, Arizona.

Welcome to the committee. We will take your testimony in the order in which you were called. Your entire testimony will be placed in the record. To the extent you wish to summarize, please feel comfortable to do so; and any supporting documentation that you have will also be placed in the record.

Mr. Heller.

STATEMENT OF THOMAS HELLER

Mr. HELLER. Mr. Chairman, thank you very much for the opportunity to present our testimony here today to your committee. And, Congressman Johnson, thank you very much also for the warm introduction. The State of South Dakota, can I tell you, it is a little cooler back there?

Mr. MILLER. It is cooler everywhere.

Mr. HELLER. Mr. Chairman, I represent Missouri Basin Municipal Power Agency. We are a joint action agency in the State of South Dakota. We have members in North Dakota, South Dakota, Iowa, and Minnesota—58, to be exact. We are municipal systems that purchase power from the Western Area Power Administration and we provide supplemental energy to them.

My statement has been provided to your committee and I will summarize it in very brief fashion, if I may, please.

The Missouri Basin and its members support integrated resource planning as an important tool in meeting our mission of serving our customers' energy needs at the lowest possible cost.

The development and implementation of the IRP will have a profound effect on the Missouri Basin; expressly, by agreement, all of the load growth established or estimated by an IRP in our member communities will be served by Missouri Basin;

Supply side resources selected by our IRP will be acquired by the Missouri Basin Municipal Power Agency; and

Cost-effective demand-side opportunities that can provide timely system benefits while directly acquired by the Agency's member utilities will most likely receive some financial assistance from the Agency.

Missouri Basin strongly supports linkage of contract extensions and the integrated resource plans. There are strong substantive and policy reasons for knowing both the size of the allocation and the term of the contract prior to preparation of an integrated resource plan. Failure to address these critical issues will undermine effective integrated resource planning, discourage thoughtful resource decisions, and reduce demand-side options and their associated environmental benefits.

Providing WAPA customers with long-term contract extensions is necessary for a variety of reasons. To fully appreciate the need for long-term contracts, it is necessary to think of an IRP as a long-range strategic plan. For utilities to prepare meaningful and long-range plans, the size, availability and price of existing resources must be known. Then, to determine cost-effective resource options, a utility estimates anticipated load growth and the attributes of new resource, including cost and availability.

For Missouri Basin Members, the Pick-Sloan allocation is the "first-tier resource," currently satisfying about two-thirds of each member's baseload energy requirements. The Agency's supplemental resources are planned around the attributes of the WAPA allocation. The Agency resource decisions would be dramatically affected by either reductions in the WAPA allocations or uncertainties in the resource availability. In fact, in the worst case, uncertainty in WAPA allocations could render the Agency's integrated resource plan meaningful. If our members' WAPA allocations are uncertain, then the Agency will have to plan for more resources than may be necessary in order to assure our availability to meet our contractual responsibilities to our members. If these additional resources prove ultimately unnecessary, then the Agency and its members will have needlessly invested considerable time and money, resulting unnecessarily in higher wholesale rates to our Members. On the other hand, underbuilding resources would subject us to the risk and uncertainties of the wholesale power market at a time when other utilities might be similarly resource constrained.

Long-term contracts are an industry norm. Many resource decisions involve long lead times. Engineering, permitting and construction usually take five to ten years and often fifteen years. The larger the resource being developed, the longer the time period needed. Consequently, long-term contracts habitually refer to contracts of no less than fifteen and usually twenty-five years or longer.

The Agency's long-term contracts with its Members are for thirty-five years. We also have a policy not to extend any long-term contracts to any new Members for periods less than fifteen. Currently, we have none of that short period.

Long-term WAPA contracts not only benefit power customers, they also benefit the environment. As the Draft Environmental Impact Statement has shown, the longer the contract term, the greater the environmental benefit.

Missouri Basin believes that existing customers should be provided essentially the same allocations as they receive today. Full resource allocations are consistent with the customers' need for resource certainty.

Some suggest that WAPA should reserve a large portion of the available resource to be able to respond to changes in hydrology and project operations and to new customer demands. Missouri Basin believes that satisfaction of these concerns does not require large allocation reserves.

Missouri Basin also recognizes that the Draft Environmental Impact Statement is not a perfect document. Our comments to the Western Area Power Administration raised a number of concerns. At its core, however, the document conclusions are supportable. Furthermore, the document provides the means for addressing the critical issues of contract terms and conditions; specifically, these are long-term resource certainty, retention of high levels of current allocations, and timely knowledge of the size and duration of these allocations.

We believe adoption of the Draft Environmental Impact Statement Option 8 satisfies these needs.

In conclusion, current Pick-Sloan contracts expire in the year 2000. While six years may seem like a long time, this is a very short horizon for utility planners. If WAPA is forced to scrap the DEIS, Pick-Sloan customers would only have three years to acquire potentially large resources for the replacement. This would be a disadvantage to programs that take four or five years to implement.

We believe certain issues must be resolved within the next year, specifically long-term Pick-Sloan contracts, allocations similar in size and allocations for timely decisions. We believe these needs can be satisfied within the framework established by the DEIS. We are willing to consider other contracts other than 8—even options not under the DEIS—provided the resulting preferred alternative conforms with the basic needs we have outlined.

With that, I would like to thank you very much for the opportunity to testify before the subcommittee.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Heller follows:]

Missouri Basin
municipal power agency

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Testimony of

Tom Heller, General Manager

Missouri Basin Municipal Power Agency

before the

Oversight and Investigations Subcommittee

of the

House Natural Resources Committee

on

WAPA's Draft Environmental Impact Statement

June 16, 1994

Printed on
recycled paper.

Mr. Chairman, thank you for the opportunity to testify before this subcommittee on the Draft Environmental Impact Statement (DEIS) recently issued by the Western Area Power Administration (WAPA). I am Tom Heller, General Manager of the Missouri Basin Municipal Power Agency (Missouri Basin or Agency). Missouri Basin is a joint action agency comprised of 58 municipal utilities located in Iowa, Minnesota, North Dakota and South Dakota. Missouri Basin members hold their own individual WAPA allocations. The Agency is the supplemental power supplier for its member utilities, meeting the wholesale power needs of its members not satisfied by their allocations from WAPA of power generated at the mainstem dams on the Missouri River (Pick-Sloan Project).

Missouri Basin and its members support integrated resource planning as an important tool in meeting our mission of serving our customers energy needs at the lowest possible cost. The Agency worked with this Committee in the drafting of Section 114 of the Energy Policy Act of 1992. Missouri Basin is currently developing its own IRP (though not required to by Section 114), which our membership is interested in using to satisfy their own Section 114 responsibility by having Missouri Basin serve as an "IRP Cooperative" under the terms of that provision.

The development and implementation of the IRP will have profound effects on Missouri Basin:

- by agreement, all of the load growth estimated by the IRP in our member communities will be served by Missouri Basin;
- supply side resources selected by the IRP will be acquired by the Agency; and
- cost-effective demand-side opportunities that can provide timely system benefits, while directly acquired by the Agency's member utilities, will most likely receive some financial assistance from the Agency.

As you know, WAPA's DEIS quantifies the environmental benefits of pursuing IRPs under various proposals. Specifically, the DEIS reviews the impact on integrated resource planning of alternative scenarios for extending existing WAPA contracts and power allocations.

Missouri Basin strongly supports this "linkage" of contract extensions and IRPs. There are strong substantive and policy reasons for knowing both the size of the allocation and the term of the contract prior to preparation of an IRP. Failure to address these critical issues will undermine effective integrated resource planning, discourage thoughtful resource decisions and reduce demand-side options and their associated environmental benefits.

Importance of Long-Term Contracts

Providing WAPA customers with long-term contract extensions is necessary for a variety of reasons. To fully appreciate the need for long-term contracts it is necessary to think of an IRP as long-range strategic plan. For utilities to prepare meaningful long-range plans, the size, availability and price of existing resources must be known. Then, to determine cost-effective resources options, a utility estimates anticipated load growth and the attributes of new resources -- including cost and availability.

For Missouri Basin's members, the Pick-Sloan allocation is the "first tier resource" -- currently satisfying about two-thirds of each member's baseload energy requirements. The Agency's supplemental resources are planned around the attributes of the WAPA allocation. Attributes of the WAPA allocation that are considered in resource acquisition decisions include seasonal availability, load following ability, dispatchability, fuel diversity and price. It is not simply a matter of knowing that our member utilities will receive "a fairly large hydropower allocation," we need to know the details of that resource availability as well as the total size and cost.

The Agency's resource decisions would be dramatically affected by either reductions in WAPA allocations or uncertainties in resource availability. This uncertainty substantially complicates Missouri Basin's preparation of an IRP -- since the Agency must make up any resource reduction from WAPA -- and diminishes the value of the IRP in promoting cost-effective decisions. This uncertainty also increases the likelihood of developing traditional fossil-fired resources, thereby reducing development of otherwise cost-effective demand-side programs and their associated environmental benefits. In the worst case, this uncertainty in WAPA allocations could render the Agency's IRP meaningless.

If our members' WAPA allocations are uncertain, then the Agency will have to plan for more resources than may be necessary in order to assure our ability to meet our contractual responsibility to our members. If these additional resources prove ultimately unnecessary, then the Agency and its members will have needlessly invested considerable time and money, resulting unnecessarily in higher wholesale rates to our members. On the other hand, underbuilding resources would subject us to the risk and uncertainties of the wholesale power market at a time when other utilities might be similarly resource constrained.

Long-term contract extensions minimize risk and increase certainty in IRP decisions. Detailed knowledge about the size and availability of resources -- particularly large, baseload resources -- is essential for the meaningful preparation of an IRP.

Long-Term Contracts Are Employed Throughout the Industry

Long-term contracts are an industry norm for a majority of resources. Utilities secure long-term power supplies through direct ownership, lease arrangements, life-of-unit contracts, and other long-term agreements. Utilities attempt to achieve the greatest resource certainty for those power supplies that are (1) baseload resources, and (2) least cost. These are precisely the attributes of the Pick-Sloan allocation for Missouri Basin's members.

Many new resources decisions involve long lead times. Engineering, permitting and construction usually takes five to ten years and often takes fifteen years. The larger the resource being developed, the longer the time period needed. Consequently, "long-term" contracts habitually refer to contracts of no less than 15 years and usually 25 years or longer. The Agency's long-term contracts with its members are for 35 years and the Agency's policy is to not extend long-term contracts to any new members for a period less than 15 years.

Even in this dramatic period of change in the industry, utilities are entering into long-term bulk power supply arrangements. While the arrangement may be a contract with a non-utility generator (instead of utility owned generation), utilities are still securing a majority of their baseload and peaking resources on a long-term basis.

Environmental Benefits Associated With Long-Term WAPA Contracts

Long-term WAPA contracts do not only benefit power customers, they also benefit the environment. As the DEIS shows, the longer the contract term the greater the environmental benefits. This correlation exists because greater resource certainty enables utilities to make long-term investments in demand-side and renewable resources. Given short planning horizons and uncertain resource availability, utilities are likely to select those resource options that have shortest lead times, high operational flexibility, resource certainty and low initial capital costs. Under this scenario, investments in combustion turbines -- rather than energy efficiency and renewables -- are most likely.

Furthermore, if WAPA allocations are reduced -- either in size or duration -- it is likely that this renewable, baseload resource will be replaced in part through fossil-fired generation. Thus, reductions in WAPA allocations would result in increases in emissions from current WAPA customer replacement resources.

Contracts Should Provide Largest Possible Resource Allocation

Missouri Basin believes that existing customers should be provided essentially the same allocations they receive today. Full resource allocations are consistent with the customers' need for resource certainty.

Some suggest that WAPA should reserve a larger portion of the available resource to be able to respond to changes in hydrology and project operations and to new customer demands. Missouri Basin believes that satisfaction of these concerns does not require large allocation reserves.

The Agency recognizes that changes in the Corps of Engineers' Master Manual for operation of the Missouri River, Endangered Species Act compliance efforts and other factors could result in reduced resource availability. Missouri Basin and its members fully expect that any new WAPA contract -- like current contracts -- will include adequate provisions for reducing allocations in order to respond to any of these factors. We believe it is more appropriate to respond to these events if and when they occur, rather than withholding a portion of customer allocations in anticipation of an event that may not materialize.

Missouri Basin recognizes that there may be new applications for allocations of federal hydropower. We believe, however, that the two percent reserve contained in DEIS Option 8 is sufficient to satisfy the demand of these new customers. It must be recognized that, under existing federal power policies, allocations can only be made to eligible preference entities (e.g., non-for-profit utilities with local distribution responsibility). Given this limitation, as well as the requirement that the customer be located within the basin watershed, we believe that the two percent reserve will be more than adequate. For the Pick-Sloan system, this two percent reserve equals about 50 MW. Compare this to the average WAPA allocation of the Agency's members of 6 MW.

In the Pick-Sloan region, the largest new customer demand has been for pumping power for water supply for Native Americans and other municipal and industrial customers. The policy of this Committee, as established in the Mni Wiconi bill and other legislation and supported by Missouri Basin, is to serve these new loads through power allocated from what was previously reserved for seasonal pumping for Pick-Sloan irrigation projects. Continuation of this practice does not require a reduction in the allocations of current Pick-Sloan customers.

Agency Members Are Leaders In Conservation

The Agency and its members share this Committee's desire to encourage integrated resource planning and demand-side management investments. The Agency's members have been leaders in this field. Through demand-side management investments, our members collectively have 50 MW of peak demand that is interruptible. This peak shaving effort reduces our members coincident peak demand by 10 percent. This compares favorably with the industry average.

I would like to highlight some of our members' activities:

- Sioux Center, IA Municipal Utilities has achieved nearly 100 percent customer saturation for its water heat wrap program. This stunning achievement was accomplished without financial incentives. In addition, Sioux Center has an aggressive new building efficiency program, a methane gas recapture program at its waste treatment plant, and a derived fuel (recycled cardboard) boiler at the local high school.

- Under state law, all of our Minnesota members invest one percent of gross revenues in demand-side management activities. Similarly, many of the Iowa public power systems voluntarily meet that State's one and one-half percent conservation investment policy.

- Vermillion, South Dakota installed a load management system in 1986. The system is used to cycle water heaters, central air conditioning and electric heat for both residential and commercial customers. Additionally, the City has encouraged the strategic use of compact fluorescent lighting, converted all street lights to the more efficient high pressure sodium lights, and loss evaluated transformers to ensure the most cost-effective benefits over the entire life of the transformer. The City estimates a savings of 1500 kW from their winter peak and 2450 kW in the summer. A 20 percent reduction from their potential estimated peaks.

- Benson, Minnesota has aggressively managed its electrical loads since 1980. Perhaps one of the most impressive success stories is the City's ability to interrupt 690 kW of industrial load on a voluntary basis trough a simple phone call at times of peak power requirements. Customers interrupt their own operations with no incentives offered by the City. 690 kW represents more than ten percent of the entire City load at peak times. This interruption would likely occur three to five times during an average year.

Importance of WAPA DEIS

Missouri Basin recognizes that the DEIS is not a perfect document: our comments to WAPA raised a number of concerns. At its core, however, the document's conclusions are supportable. Furthermore, the document provides the means for addressing the critical issues of contract terms and conditions.

As I stated earlier, to make sound resource decisions, minimize adverse environmental effects, promote demand-side management and renewable resource acquisition, and facilitate responsible integrated resource planning, WAPA customers need:

- long-term resource certainty;
- retention of high levels of current allocations; and
- timely knowledge of the size and duration of allocations.

We believe adoption of the DEIS Option 8 satisfies these needs.

Delay Causes Unacceptable Consequences for Pick-Sloan Customers

It is not my intent to minimize the criticisms of the WAPA DEIS. However, it must be recognized that failure to reach prompt and appropriate decisions will have unacceptable consequences for Pick-Sloan customers.

Current Pick-Sloan contracts expire in the year 2000. While six years may seem like a long time to some, it is a very short horizon for utility planners. If WAPA is forced to scrap the DEIS and start again, it is our concern that a new process -- particularly Basin-specific marketing plans and associated Environmental Impact Statements -- could cause delays of greater than three years. Leaving Pick-Sloan customers with only three years to acquire potentially large sources of replacement power is simply unacceptable. This short time frame will also disadvantage the many cost effective demand-side programs that take four to five years to fully implement.

Conclusion

Missouri Basin and its member utilities believe certain issues must be resolved within the next year, specifically:

- long-term Pick-Sloan contract extensions;
- allocations similar in size to current allocations; and
- timely decisions.

We believe that these needs can be satisfied within the framework established by the DEIS. We are willing to consider options for contract terms and conditions other than Option 8 -- and even options not outlined in the DEIS -- provided that the resulting preferred alternative conforms to the basic needs we have outlined above.

Mr. MILLER. Mr. Barrett.

STATEMENT OF CLIFFORD BARRETT

Mr. BARRETT. Mr. Chairman, I am executive director of the Colorado River Energy Distributors Association. CREDA is comprised of 141 nonprofit electric utilities that purchase power marketed by the Salt Lake City area office of Western Area Power Administration. CREDA members serve some three million people in six States. Its members purchase approximately 85 percent of the Colorado River Storage Project power resources. Because of the significant role that Federal hydropower plays in the resource mix of CREDA member utilities, CREDA has a very large stake in how Western implements the proposed energy planning and management program and the integrated resource planning requirements of section 114 of the Energy Policy Act before 1992.

We appreciate this opportunity to discuss issues relating to EPMP–EIS. We also appreciate the opportunities we have had over the past several months to meet with your staff to explore legislative resolution of a number of other CRSP issues, including funding of the endangered fish recovery program.

The power generation and transmission facilities built as part of the CRSP have proved to be a valuable resource for CREDA members and for the Nation. CRSP power revenues repay the Federal investment in the project's power features and more than 95 percent of the Federal investment in the participating irrigation projects in the upper basin. According to an October 1989 report by the GAO, power revenues will ultimately repay more than five times the Federal power investment.

I will summarize my remarks today, but ask that the full text of my testimony and the comments submitted by CREDA to Western on the EPMP–EIS be included in the hearing record. I also request the comments submitted by the Irrigation and Electrical Districts Association of Arizona also be included in the record. That association is a member of CREDA and their comments highlight the plight of small customers whose major power need is for agricultural pumping.

CREDA is supportive of the IRP process. But those IRP programs are consistent with the business objectives of public power utilities, to provide the lowest-cost power available to our customers.

CREDA members were involved in demand-side management and energy efficiency programs prior to the enactment of the Energy Policy Act. Some are outstanding examples of aggressive application of demand-side management and techniques.

For example, DSM activities, begun in 1986, have saved the Salt River Project in Arizona about 70 megawatts of capacity. Over the next 20 years, they plan to further reduce their peak demand by 540 megawatts through additional DSM programs.

CREDA was an active participant in the negotiations and drafting that produced the IRP legislation that forms the basis for Western's proposed IRP program.

Beyond repeating the Integrated Resources Planning requirements of the Energy Policy Act, the EIS has only sketchy information on the proposed IRP process. CREDA assumes that when the proposed IRP rules are issued they will contain sufficient detail to permit customers to make informed comments.

In our comments to Western on the EIS, we made a number of specific recommendations which we urge be included in the proposed IRP rules. We will not repeat those suggestions since they will be made a part of the hearing record.

Concerning Western's proposed power marketing initiative, CREDA concurs with Western's assertion that quality utility planning is enhanced when a customer's existing resources are stable and reliable. For that reason, we support the inclusion of a 25-year contract extension as part of the IRP process.

We understand the Chairman's concern that long-term contracts may limit Western's future ability to allocate power for new purposes and to new customers. We believe those concerns can be addressed as part of the contract extension and that the benefits in terms of high-quality resource planning outweigh the possible downsides.

As I said earlier, the CRSP power resource plays a very significant role in the resource portfolio of CREDA members. The allocations of Federal power provide a cost-effective base to which CREDA members can add additional resources, including demand-side management and energy efficiency programs to meet customer demand. The more certainty Federal power customers have about the Federal resource, the longer-range view they can take about acquiring and implementing complementary resources.

A utility's ability to rely on the availability of existing resources has a direct impact on its long-range planning. I recommend to the committee the comments submitted to Western by the City of Palo Alto, which I have attached to this statement and request be made a part of the hearing record.

Palo Alto indicates that utilities that are unsure about the stability of long-term resources will favor acquisition of new resources that have relatively low capital costs and higher operating costs, such as fossil-fueled generation. In contrast, utilities that have more certainty about the time and scope of their resources can increase their commitment to renewable resources and resources that utilize more efficient technologies, which also tend to have relatively higher capital costs and lower operating costs.

CREDA supports the committee's desire to promote consideration and acquisition of renewable and energy-efficient resources by Western customers We believe these goals can best be achieved by approving a 25-year contract extension for existing customers as a part of the IRP process.

CREDA does not support Western's proposal to reserve a portion of the available Federal resources in a pool to be used for possible future uses or customers. CREDA appreciates the fact that changing societal values and new circumstances may necessitate changes in power allocations to accommodate changes in operations, new uses or new customers. At this time, however, such changes are, in most cases, speculative.

CREDA is aware of the fact that changing social values and goals can have dramatic effects on the operation of the Western hydropower system. The important point in the context of the issues of this hearing is that existing supply contracts have had very little, if any, effect on decisions made to change power plant operations.

Glen Canyon Dam is a good example. CREDA has been actively engaged in the Glen Canyon Dam operational change issues from the onset. Although we may have had differences of opinion with this committee at the beginning of the legislative process on the Grand Canyon Protection Act, we supported the enactment of the final conference report. Since passage of the law, we have been active in the EIS process and the determination of new operational criteria for the dam.

At no time did we expect or assert that the existing contracts could prevent needed changes in operation. We have, however, worked hard to assure that changes are based on sound scientific data and have accommodated those changes within the existing contracts. We believe it is possible to write long-term contracts in a way that fully protects the government's ability to make needed operational changes and still provide the customers with the degree of stability needed to do good long-term planning.

The same principle applies to meeting future new objectives in the marketing of Federal power. While the amounts and time of such new needs are not fully known today, it is certainly possible to write long-term contracts which allow for future changes in use, yet provide a degree of stability for long-term planning by existing contractors.

CREDA believes these issues can be resolved within and as a part of Western's existing process. Because of the wide disparity among projects on potential future needs and possible operational changes, these issues can best be solved on a project-by-project basis. We urge the committee and Western to work with the customers to solve the length-of-contract problems and are ready to participate in the resolution of those issues. There is no need to delay this program and the benefits it will produce.

I appreciate the opportunity to speak with you on it. Thank you.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Barrett and attachments follow:]

CREDA
COLORADO RIVER ENERGY DISTRIBUTORS ASSOCIATION

Testimony of

Clifford Barrett

Executive Director, Colorado River

Energy Distributors Association

at the

House Natural Resources Committee

Subcommittee on Oversight and Investigation

on

Marketing of Federal Power by the

Western Area Power Administration

June 16, 1994

Mr. Chairman, members of the Committee, I am Clifford Barrett, the Executive Director of the Colorado River Energy Distributors Association (CREDA). As you may know, CREDA is comprised of 141 non-profit electric utilities that purchase power marketed by the Salt Lake City Area Office of the Western Area Power Administration (Western). CREDA members serve some three million people in six states and its members purchase approximately 85% of the Colorado River Storage Project (CRSP) power resources marketed by the Salt Lake City Office. Because of the significant role federal hydropower plays in the resource mix of CREDA member utilities, CREDA has a very large stake in how Western implements the proposed Energy Planning and Management Program (EPMP) and the integrated resource planning requirements of Section 114 of the Energy Policy Act of 1992.

We appreciate this opportunity to discuss issues relating to the EPMP-EIS. We also appreciate the opportunities we have had over the past several months to meet with your staff to explore legislative resolution of a number of other CRSP issues, including funding of the endangered fish recovery program.

The power generation and transmission facilities built as part of the CRSP have proved to be a valuable resource for CREDA members and for the nation. CRSP power revenues repay the federal investment in the project's power features and more than 95% of the federal investment in participating irrigation projects in the Upper Basin states. According to an October 1989 report by the General Accounting Office (GAO/RECD-90-2FS), power revenues will ultimately repay more than five times the federal power investment. CRSP power revenues have also been applied to pay costs of the Glen Canyon Dam environmental studies and EIS and for studies relating to the endangered species recovery program administered by the Fish and Wildlife Service.

Mr. Chairman, I will summarize my remarks today but ask that the full text of the comments submitted by CREDA to Western on the EPMP-EIS be included in the hearing record. I would also request that comments submitted by the Irrigation and Electrical Districts Association of Arizona (IEDA) be included in the record. IEDA's members are also members of CREDA. Their comments highlight the problems of small customers whose major power need is for agricultural pumping.

CREDA is very supportive of the IRP process. We support IRP because it makes good business sense to evaluate a full range of supply-side and demand-side options to make an informed choice about cost-effective resource retention and acquisition. The goals of IRP programs are consistent with the business objective of public power utilities: to provide the lowest cost power available to our customers. Public power systems have no economic reason to prefer supply-side resources over demand-side resources because they do not earn a rate of return on capital investments.

CREDA members were involved in demand-side management and energy efficiency programs prior to enactment of the Energy Policy Act. Some are outstanding examples of aggressive application of demand-side management (DSM) techniques. For example, DSM initiatives begun in 1986 have saved the Salt River Project (SRP) in Arizona about 70 MW of capacity. SRP plans to reduce peak demand for the next 20 years by another 540 MW through additional DSM programs.

In addition, CREDA was an active participant in the negotiations and drafting that produced the IRP legislation that forms the basis for Western's proposed IRP program. With that introduction, I would like to move to specific comments on the EPMP-EIS.

COMMENTS ON THE PROPOSED ENERGY PLANNING (IRP) PROGRAM

Beyond repeating the Integrated Resources Planning (IRP) requirements of the Energy Policy Act -- which we helped draft -- the EIS has only sketchy information on the proposed IRP process. CREDA assumes that when the proposed IRP rules are issued, they will contain sufficient detail to permit customers to make informed comments. In our comments to Western on the EIS, we made a number of specific recommendations which we urge be included in the proposed IRP rules. We will not repeat those suggestions here since they will be made part of the hearing record.

COMMENTS ON PROPOSED POWER MARKETING INITIATIVE

Long-Term Contracts

CREDA concurs with Western's assertion that "Quality utility planning is enhanced when a customer's existing resources are stable and reliable." For that reason, we support inclusion of a 25-year contract extension as part of the IRP process. While we understand the Chairman's concern that long-term contracts may limit Western's future ability to allocate power for new purposes and to new customers, we believe those concerns can be addressed as part of the contract extension and we believe that the benefits -- in terms of high quality resource planning -- outweigh the possible downsides.

As I said earlier, the CRSP power resource plays a very significant role in the resource portfolio of CREDA members. The allocations of federal power provide a cost-effective base to which CREDA members can add additional resources, including demand-side management and energy efficiency programs, to meet customer demand. The more certainty federal power customers have about the federal resource, the longer-range view they can take about acquiring and implementing complementary resources.

A utility's ability to rely on the availability of existing resources has a direct impact on its long-range planning. I recommend to the Committee the comments submitted to Western by the City of Palo Alto, which I have attached to this statement and request be made a part of the hearing record. Palo Alto indicates that utilities that are unsure about the stability of long-term resources will favor acquisition of new resources that have relatively low capital costs and higher operating costs, such as fossil-fueled generation. In contrast, utilities that have more certainty about the timing and scope of their resources can increase their commitment to renewable resources and resources that utilize more efficient technologies, which tend to have relatively higher capital costs and lower operating costs.

CREDA supports the Committee's desire to promote consideration and acquisition of renewable and energy efficient resources by Western customers. We believe these goals can best be achieved by approving a 25-year contract extension for existing customers as part of the IRP process.

Resource Pool

For similar reasons, CREDA does not support Western's proposal to reserve a portion of the available federal resource in a pool to be used for possible future uses or customers. CREDA appreciates the fact that changing societal values and new circumstances may necessitate changes in power allocations to accommodate changes in operations, new uses or new customers. At this time, however, such changes are, in most cases, speculative. CREDA is aware of the fact that changing social values and goals can have dramatic effects on the operation of the western hydropower system. The important point in the context of the issues in this hearing is that the existing power supply contracts have had very little if any effect on the decisions made to change plant operations.

CREDA has been actively engaged in the Glen Canyon Dam operational change issues from the onset. Although we may have had differences of opinion with this Committee at the beginning of the legislative process on the Grand Canyon Protection Act, we supported enactment of the final conference report. Since passage of the law, we have been active in the EIS process and the determination of new operational criteria for the dam. At no time did we expect or assert that the existing contracts could prevent needed changes in operation. We have, however, worked hard to assure that changes are based on sound scientific data, and have accommodated those changes within the existing contracts. We believe it possible to write long-term contracts in a way that fully protects the government's ability to make needed operational changes and still provide the customers with the degree of stability needed to do good long-term planning.

The same principle applies to meeting future new objectives in the marketing of federal power. While the amounts and time of such new needs are not fully known today, it is certainly possible to write long-term contracts which allow for future changes in use, yet provide a degree of stability for long-term planning by existing contractors.

CREDA believes that these issues can be resolved within and as a part of Western's existing EPMP-EIS and IRP rulemaking process. Because of the wide disparity among the projects on potential future needs and possible operational changes, these issues should be solved on a project-by-project basis. There is no need to delay this program and the benefits it will produce.

We urge the Committee and Western to work with the customers to solve the length of contract problems and are ready to participate in the resolution of these issues. We would not like to see any delay in the EIS or IRP rulemaking process.

SUMMARY/CONCLUSION

1. CREDA Members have been strong supporters of DSM and conservation for many years.

2. Stable access to resources, including Western's generation and transmission, is a key element of adequate IRPs, and the basis for developing DSM and renewable energy resources. Long-term contracts are essential to the IRP process.

3. Long-term contracts have not and will not impair the Administration's ability to make changes in hydropower operations to satisfy environmental needs.

4. Contracts can be written to provide the stability needed and also provide mechanisms to allow future reallocation of the resource to meet changing social goals and needs.

5. CREDA believes these issues can and must be worked out within the on-going EPMP EIS and the IRP Rulemaking process on the current time frame and schedule.

6. CREDA is prepared to work with Western, the Department and the Committee to solve these issues on a timely basis.

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CREDA

COLORADO RIVER ENERGY DISTRIBUTORS ASSOCIATION

ARIZONA
Arizona Municipal Power Users Association
Arizona Power Authority
Arizona Power Pooling Association
Irrigation and Electrical Districts Association
Navajo Tribal Utility Authority (also New Mexico, Utah)
Salt River Project

COLORADO
City of Colorado Springs
Platte River Power Authority
Tri-State Generation & Transmission Cooperative (also Nebraska, Wyoming)

NEVADA
Colorado River Commission of Nevada
Silver State Power Association

NEW MEXICO
Farmington Electric Utility System
Plains Electric Generation & Transmission Cooperative (also Arizona)
City of Truth or Consequences

UTAH
Intermountain Consumer Power Association (also Arizona, Nevada)
City of Provo
Strawberry Electric Service District
Utah Municipal Power Agency

WYOMING
Wyoming Municipal Power Agency

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May 12, 1994

Mr. Bob Fullerton
Western Area Power Administration
P.O. Box 3402, A6100
Golden, CO 80401-0098

Re: Comments on the Western Area Power Administration Energy Planning and Management Program Environmental Impact Statement (EPMP-EIS)

Dear Mr. Fullerton:

The Colorado River Energy Distributors' Association is comprised of 141 non-profit utilities that purchase power marketed by the Salt Lake City Area Office of the Western Area Power Administration. CREDA members serve some 3 million people in 6 states and its members purchase approximately 85% of the power resources marketed by the Salt Lake City Area Office of Western. CREDA members have an immense stake in the outcome of the deliberations over how Western will implement the proposed EPMP program and Section 114 of the Energy Policy Act of 1992 (EPAct). CREDA appreciates the opportunity and offers the following comments in the draft EIS.

General Comments

The federal hydropower which is marketed by Western is and has been the cornerstone of the preference customers resource development of the past forty years. Western's transmission system, in conjunction with the federally generated power has been the genesis of a regionally developed, reliable electric power supply system that serves the public in the western United States. The future administration and operation of that electric system is vitally significant to the future of the power supplying utilities and their customers. The economic viability of many rural areas depends on this system. Western, however, is not a public utility with traditional utility responsibilities. Western is a marketing agency of federally generated hydropower that constitutes a partial resource for municipal, cooperative and other preference entities.

In the Purpose and Need Statement, Western sites the purposes of the EPMP EIS as:

- Promote the stable, efficient, and economical use of electrical generation and conservation resources by Western's customers

- Promote consideration by Western's long-term firm power customers of cost-effective, demand-side management and supply-side alternatives including renewable resources, as part of their long-term planning process.

- Market Federal power on a long-term basis in accordance with Western's mission as a power marketing administration.

- Develop the Program in an equitable manner consistent with Western's legal obligations and constraints, including the obligation to carry out Section 114 of the Energy Policy Act of 1992.

We concur with the above stated purposes, but we would also add the following Objectives for Western:

- Assure a stable and reliable federal hydropower resource

- Assure rate stability through commitments by Western and the operating agencies (U.S. Bureau of Reclamation and Corps of Engineers) to:

  (i). Hold normal operating and maintenance (O&M) expense increases below the rate of inflation,

  (ii). Provide for and review of O&M planning decisions.

  (iii). Continue to utilize cost based rate methodology

- If the federal goal is to minimize adverse environmental impacts, then Western should hold down the rates of its renewable hydropower resources to reduce the need for customers to seek out alternative generation resources that may have more environmental impact.

- Provide flexibility to mutually agree and incorporate material changes in the federal hydropower marketing program through customer funding, joint participation, and other means intended to reduce program costs.

We feel strongly that these objectives are important to all Western activities and should especially be included in the EPMP effort to set the tone for the proposed IRP rules.

Most of Western's customers have a long and active history of encouraging the wise use of electric energy and supporting the development of renewable resources. Many of Western's customers have prepared IRP's on their own initiative before they were required to do so by the effective date pursuant to EPAct. Much of the demand side management (DSM) and renewable resource effort is not easy to implement and, in most cases, there are cheaper and more reliable alternatives available. However, the preference customers have, on their own initiative, developed DSM programs, done screening studies, developed pilot programs and actively pursued and encouraged the wise and efficient use of this essential service prior to such programs being required by contract or law. The wholesale suppliers of electricity have limited opportunity for demand side efficiencies but, in close cooperation with their distribution members, they can accomplish the objectives of the IRP process. However, the laws of physics, not the level of effort or level of expenditures, will dictate the ultimate efficiency. Thus, the major effort for DSM will fall to the distribution entities and, with the encouragement of the wholesale supplier, will improve energy efficiency where appropriate.

Energy Management Program

Beyond repeating the requirements of the EPAct, the draft EIS has only sketchy information on the proposed IRP program to be established in a rule making program. CREDA assumes the proposed IRP rules will be in sufficient detail to allow for detailed comments. The following should be considered as the proposed IRP rules are drafted.

- Western's acceptance (or rejection) of an IRP submitted by a customer must be based on the customers compliance with a well defined process and specific customer goals. The existing customers should have the first right (on a pro rata basis) to any unallocated power resulting from the reduction in an allocation or penalty. Western should not assume any regulatory or judiciary authority over the plan but rather focus its role on administrative review of the submitted IRP plan to assure appropriate recognition of the planning criteria listed in section 204 of the EPAct. We believe this is consistent with the Congressional intent. We understand that the Administrator of Western has the authority to determine compliance with the proposed IRP rules; however, we believe that the process should provide for a dispute resolution consultive process to allow for further clarification of issues and alternatives contained in the IRP. The provisions of the Alternative Dispute Resolution Act should be considered. The EPAct provides that the Administrator shall accept the IRP which a customer has prepared in response to another state or federal IRP requirement which substantially complies with EPAct requirements. Western's proposed IRP rules should recognize an IRP requirements by another jurisdiction. To avoid confusion, and minimize conflicting requirements with other jurisdictions, the proposed IRP rules should not list specific requirements but should only deal in generalities with the seven elements enumerated in EPAct.

- If methodologies which require lengthy lead times are required (e.g., end-use load forecasting), they should be required in the second round of IRP filings. Also, if Western plans to adopt stringent requirements for each element of EPAct, Western should provide that any such requirements should not apply to any customer who is required to meet the requirements of a state or other federal agency which addresses the elements of EPAct. The customer's governing body review and approval of an IRP should be sufficient to comply with the public process.

The proposed IRP rules should only apply to the contracting entities and should not automatically apply to all recipients of federal power. The proposed IRP rules should be flexible enough to accommodate regional and project specific differences and the proposed IRP rules should allow the existing joint action agencies and G&T's to be eligible for the extension of time for filing the initial IRP as a cooperative agency.

The draft EIS states that Western would establish different regulations for certain small customers with total energy sales on usage of 25 GWh or less.

Western should allow a qualifying small customer two options to consider; one being for the small customer to prepare and submit an IRP, the other option being for the small customer to submit a program which considers reasonable opportunities to meet future energy service requirements at the lowest possible cost, and minimize, to the extent practicable, adverse environmental effects.

It is not administratively practical for the small customers, with loads of 25 GWh or less, to prepare an IRP which would require them to describe and evaluate each DSM technology when many of the technologies are not applicable to the small utilities situation. Environmental, economical and social factors are regionally and seasonally sensitive and the cost for evaluating the factors for a small system is administratively overly burdensome.

An effective IRP for a small customer should consider all aspects of their power consumption. For those where irrigation pumping is a significant part of their electrical load, they need to look at irrigation efficiency and water saving methods in addition to energy saving methods on the electrical side. All these options reduce their electrical consumption. You cannot expect these customers to reduce their consumption of their federal contract amount. The most cost effective option is to continue to receive their full federal allotment and reduce their purchase from their alternative supplier.

The development and maintenance of the DSM activity factors, for each DSM activity available to the utilities, can be a large and expensive task. In order for these activities to be useful, their factors and the utility specific data would have to be constantly maintained. Given the minimal likelihood of identifying new activities with real benefits, the cost of this extensive exercise will most likely outweigh the actual savings.

The decisions small customers have to make are usually more dependent upon the local economics and conditions for a short period rather than a long term trend or known conditions.

It will not be cost effective for the small customer to perform an IRP type analysis versus utilization of their funds to perform and maintain conservation programs. Currently, each small customer is using their funds to sponsor conservation activities and disseminating conservation information. Due to the size of utility, type of operation, and DSM activity concerns identified above, these utilities would most likely find the cost of maintaining the data bases so expensive that doing so would consume a large portion of the funds currently available for ongoing DSM activities. Thus, the cost of performing an IRP would not be cost effective.

Based upon these observations, it appears that the EPMP EIS and proposed IRP rules need to recognize the different operating requirements of the small customer. These utilities are clearly responsive to the conservation requirements, social, and political constraints placed upon their operations. Their DSM economics must be recognized and Western's review process must be flexible in allowing the use of available funds for performing conservation activities which commensurate with size.

Power Marketing Initiative

CREDA concurs with Western's statement that:

> "Quality utility planning is enhanced when a customer's existing resources are stable and reliable. To be considered a stable and reliable part of a customer's existing resources, Western's power allocation must be secure over a time frame typical of long-term firm power sales and purchases in the utility industry."

The draft EIS supports the conclusion that environmental benefits are maximized when existing contracts are extended for the greatest period of time at the highest percentage of existing allocation. The longer the contract extension period, the more continuity and "history" will be developed for existing customers to monitor, evaluate, and refine their IRP objectives and public participation processes. This will lead to better quality resource planning. The more stable the supply-side resource, the more stable a utility's demand-side management program will be. This in turn will lead to increased efficiency in demand-side efforts and permit more planning resources to be committed to demand-side programs. On the other hand, inefficiency will result by dividing the available federal hydro resource into a large number of small allocations. Such fragmentation will diminish the benefits to existing customers while only marginally enhancing the power supply for the new customers. Finally, any resources fragmentation could lead to the construction of a larger amount of non-hydro resources and attendant transmission resources, with their associated environmental consequences, to meet the load growth requirements of Western's customers.

None of the alternatives in the draft EIS contain all of the elements needed for good planning and power allocation. The benefits of an IRP are maximized if the customer has a contract extension of at least 25 years. There is no benefit in the reduction of current allocations and creation of a resource pool. Customers are already doing a good job of power conservation and planning. Most are already working on IRP's and there is no reason to doubt that they will continue to do so. There is no need to penalize or threaten them by creation of a resource pool. Contracts should be extended at 100% of the current level.

The unique nature of small utilities and irrigation pumping customers must be recognized. The customers will still have the right to cancel the contract under Article 11 of the General Power Contract Provision (1/3/89 version) in the event that the rates become intolerable. We would suggest that Western also consider a provision which would allow an additional twenty five year extension at the customers option when subsequent IRP's are submitted to Western.

We concur with the contract extension provision timing as summarized in footnote b of Table S.3 which states that the contract extension begins at the time the current contracts expire and this contract extension will be executed upon receipt of the customer's IRP by Western. In the case of the Salt Lake Integrated Projects, the contract extension would be executed upon receipt of the customer's IRP (i.e., 1995) for an extension of the existing contract from 2004 to 2029.

Resource adjustments at a frequency of less than ten years would have the same effect as a short extension period. Western's customers must have confidence that the federal hydropower resource can be relied upon in order to make financial commitments to DSM programs. To avoid creating uncertainty over the firmness of the federal hydropower resource, the resource adjustment provision should be a minimum of ten years and adjustments to allocations should only be made in response to changes in river hydrology.

CREDA appreciates the opportunity to comment on the draft EPMP EIS and Western's attempt to balance public policy direction with its customers needs. The federal system is the largest single power and transmission resource to millions of people in the West and therefore the actions that Western implements has far reaching consequences and should only be initiated with complete understanding and support of the public it serves. We encourage Western to work closely with its customers in implementing these initiatives. We understand that proposed IRP rules are being developed for the EPMP program and these proposed IRP rules will be available in June for review and comment. We are very interested in seeing the proposed IRP rules as soon as possible and we will be actively participating in the public process on these proposed IRP rules.

Sincerely,

Clifford Barrett
Executive Director

cc: Mr. John Harrington

IRRIGATION & ELECTRICAL DISTRICTS ASSOCIATION OF ARIZONA

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May 16, 1994

Mr. Bob Fullerton
Western Area Power Administration
P.O. Box 3402, A6100
Golden, Colorado 80401-0098

Re: Written Comments on the Draft Environmental Impact Statement for Western's Energy Planning and Management Program

Dear Mr. Fullerton:

The Irrigation and Electrical Districts' Association of Arizona (IEDA) is a statewide association representing irrigation, electrical and water conservation districts and the Ak-Chin Indian Community. We are also a member of the Colorado River Energy Distributors' Association (CREDA) and expressly endorse the written comments submitted by CREDA. IEDA is pleased to offer these written comments to expand upon our oral comments given jointly with CREDA's at the Phoenix hearing on this draft EIS.

Our members' loads are dominated by agricultural pumping and we have a long history of conservation activities for both water and power. Thus, we are already at the forefront of conservation practices as we have demonstrated in our compliance with your Conservation and Renewable Energy Program. We are also preparing to comply with the Integrated Resource Plan (IRP) requirement of your new Energy Management Program (EMP). We have been actively following the development of the draft environmental impact statement. We have some general comments, a suggestion for a new alternative, and specific comments on the elements of that new alternative that will also express our concerns over the array of existing alternatives and the elements thereof.

<u>DEVELOPMENT OF THIS PROGRAM SHOULD BE DRIVEN BY EXISTING STATUTORY MANDATES</u>

Western provides power under the mandate that it should charge the

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"lowest possible cost consistent with sound business principles". We will not belabor the reasons why Congress has given Western this directive. Suffice it to say that the conservation mandate of Section 114 of the Energy Policy Act of 1992 does not conflict with this mandate. Indeed, it complements the mandate by recognizing that cost control is a strong motive for conservation. You have recognized this compatibility in the draft EIS by recognizing that the purpose of your program is to "enhance efficient electric energy use" (p.v.). Thus, you can provide a significant incentive to your contractors to employ conservation practices by ensuring that the resources you sell are priced on a cost basis and that costs are curtailed to the point where your resource is less expensive than the alternative. As you well know, utilities will do whatever is necessary to hold onto their lower cost resources, including conservation activities. Maintaining your competitive posture in the wholesale market provides a strong incentive to do so.

Our members, in turn, are driven by the same "lowest cost" mandate under both federal and state laws. Moreover, economic pressure also provides a strong conservation motive. This is especially true in agriculture. Resource conservation is a way of life because power is used to deliver water to farms and water is the major controlling cost variable that can spell the difference between a profit or a loss. We need no further arm-twisting to convince us to comply with either your existing or your new conservation program. We need only a clear outline of what you expect and a set of tasks that we can reasonably be expected to accomplish.

One final preliminary observation. Reducing the amount of hydropower available to be marketed is not conservation. Without addressing issues related to demand, restrictions on hydropower merely promote fuel switching (buying steam or nuclear-based power). Your conservation program needs to focus on efficiency, not source, in dealing with electric resources.

THE PROPOSED RULES AND THE EIS NEED TO FOCUS ON A NEW ALTERNATIVE

We have reviewed the alternatives displayed in the draft EIS. We believe that each of them in the combinations presented provide obstacles to achieving a good workable conservation program that is based on sound public policy. For that reason, we will suggest to you a new combination of these elements as a new alternative which we believe stands the best chance of a high level of success. We will discuss our suggested alternative in the same two divisions you have used in the draft EIS: Energy Management Program and Power Marketing Initiative.

ENERGY MANAGEMENT PROGRAM

The cornerstone of this part of the program is the Integrated Resource Plan (IRP). While we have not yet seen any real detail on IRP's, we have considerable experience working with the Resource Planning Guide and on-site visits with staff of the Phoenix Area Office. We have developed an excellent working relationship and we believe that staff at the Phoenix Area Office understands the agricultural operations of our members and how those operations have and continue to be modified for conservation purposes.

We have two major concerns. First, we need your program to recognize that agriculture is different than other types of loads and that success in your conservation program must be measured differently for agriculture than it is otherwise. Second, we are concerned that the small customer simplified compliance program is not a common element of all alternatives in your draft EIS. We believe it should be.

THE RULES MUST RECOGNIZE HOW
AGRICULTURE IS DIFFERENT

Your rules need to clearly state that your customers will be given credit for past conservation investments that continue to provide conservation benefits. For our members, for example, that would include the ongoing benefits of laser leveling of fields, lining of ditches, pump testing programs, etc. These are major expenditures that heavily focus on water conservation and often provide power conservation benefits as well.

The rules also need to recognize how your customers with dominant agricultural loads are different. They are different because most of their energy conservation is achieved through water conservation. They are different because much of that conservation activity is site-specific on farms, and not just in water or electric distribution facilities. They are different because, at least in Arizona, they are driven by mandated state water conservation programs which, in achieving water conservation, may require more energy utilization. Thus, water conservation, especially in our desert, must come before power conservation when the two conflict. Our members should not be penalized when this happens. They are also different in the way success can be

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measured. Our members' agricultural loads are affected by two major forces that are totally beyond their control: weather and commodity prices. Weather changes trigger water uses. Commodity prices trigger crop planning decisions. These variables can substantially affect both the amount of water that must be provided and the amount of electricity that must be used. Thus, agricultural load conservation must be measured differently, i.e., by increased efficiency in the delivery of the resources, and not by some end use measurement.

THE SMALL CUSTOMER PROVISION MUST BE INCLUDED

The small customer provision is essential if this program is not to drown in its own paperwork. We well remember the difficulty that Western had in the beginning stages of the Conservation and Renewable Energy Program when it was overwhelmed by paperwork from customers large and small. There is no need to repeat that problem. Congress has recognized that sound public policy can be built on simplifying the conservation requirements for small customers. Western should clearly recognize that fact also. Your small customers have the least capability for planning and investment and have the most need for a simplified program with which they comply. All of them are ready, willing and able to comply. They need to be given realistic tasks commensurate with their size.

THE POWER MARKETING INITIATIVE NEEDS TO BE RESTRUCTURED

One of the cornerstones of providing stable and reliable resources is providing them over a long period of time. The draft EIS recognizes that the quality of utility planning is enhanced when resources can be counted on over a longer period of time. Certainty of resource availability also affects the ability to make investments for conservation purposes. This is especially true of small customers with limited capital. Maintaining a stable, long-term hydropower resource allows these small customers the opportunity to utilize both supply-side and demand-side management opportunities with some knowledge that the economic rug will not be pulled out from under them.

Yet, the amortization periods for some of the investments that the utilities or their customers will be asked to make in some instances exceed any of the possible term of contract provisions in

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the draft EIS. A forty-year useful life for either a water or power facility expenditure is not uncommon. That is true whether the expenditure is for a conservation purpose or otherwise. The EIS does not recognize this at all. The new alternative we suggest you adopt should carry with it a term of no less than twenty-five years. For your small customers especially, the federal hydropower resource needs to be lower in cost and available longer to provide the economic basis from which they can plan and try to afford conservation expenditures.

There is no rational basis for establishing a resource pool and penalizing your existing customers for complying with your conservation program by taking a portion of their resource away from them. Had you had some problem getting your customers to comply with your Conservation and Renewable Energy Program, we might see why you would consider such an economic penalty. But you did not have any difficulty in that regard. If you had some indication of significant resistance to your new program, we could see why you would build in a stick and a possible carrot to overcome such resistance. But there isn't any resistance. In short, you have absolutely no evidence that your customers will do anything other than fully embrace this new program and comply with its requirements. Under those circumstances, any resource pool established with a view toward reallocating the resource as a reward for compliance will be an exercise in futility. All of your customers will be in compliance. All of them will deserve their aliquot shares of the resource retained. You will have spent a considerable amount of our money in salaries and other overhead and have gained nothing. You cannot argue that you are saving this for some new technology. If a new conservation technology becomes available and is economically viable, you will ensure that your customers learn of it and they will be obviously motivated to employ it to maintain their hydropower resources and to save money. Parenthetically, the concept of having an inverse relationship between the length of a contract term and the percentage of renewed resource makes no sense whatsoever. The two key elements that create a stable resource are played off against each other, forcing the customer to choose which destabilizing effect will cause them the least damage.

We would be remiss if we did not comment on a suggestion by the Land and Water Fund at your Denver hearing. That group suggested reducing the resource pool to 80% on the thesis that the risk of Western having to purchase alternative capacity and energy from coal-fired steam electricity sources would be reduced. The implication was that somehow an environmental benefit would be achieved. The suggestion points out how little some people really

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know about the utility business. First, the comment ignores the capability of Western to trade hydropower resources with the Bonneville Power Administration. Second, the comment ignores the fact that the demand for the electricity exists and must be filled whether Western does the purchasing or the individual utilities do. Who signs the contract has nothing to do with conservation.

Western has suggested in some of its alternatives that it needs the ability to reexamine allocations on a periodic basis for several reasons. We understand the primal urge to retain flexibility. However, we believe that that flexibility should be retained at the WAPA customer level where it translates more closely to retail electric use, which is the true focal point of energy conservation. If Western is to act as a stabilizing force to assist its customers in implementing conservation plans, then it must accept that responsibility even in the face of changing conditions. Western is much better able to adjust to those changing conditions than its small customers are. Since the majority of its customers are small entities, Western needs to shoulder the burden of providing stability to them and the system. We understand that river operations may change. We understand that hydrologic forecasts may change. Given these circumstances, your small customers will need the flexibility to respond to changing availability of resources and prices. However, any review of allocations should take place no more than once every ten years. To do so any more frequently would be to destabilize the resource yet again. It would also fly in the face of the basic standard of utility planning which Western is employing in conjunction with its customers, the Ten Year Plan. A ten-year review of hydrologic forecasts may be valuable. Otherwise, we see no value to the customers nor any contribution to their ability to do conservation in making the availability of hydropower resources less certain.

<u>THE PROPOSED RULES SHOULD OUTLINE A PROGRAM THAT IS SIMPLE TO ADMINISTER</u>

We are concerned about the possible complexity of the Energy Management Program. The draft EIS gives little guidance about the nuts and bolts of program administration and program compliance. We hope that the guiding principle for the proposed rules will be that the process for compliance is easy to understand and straightforward in its application. We also believe that, matching a growing national trend, the proposed rules should provide for a dispute resolution mechanism that will provide an administrative safety net for the uncertainties that are likely to create problems in administration.

Thank you for the opportunity to comment on this very important program and programmatic EIS. We look forward to working with you in development of the implementing rules. Please keep us advised of your progress in preparing the rules for consideration by the customers and the public.

Sincerely,

Robert S. Lynch
Asst. Secretary/Treasurer

RSL:psr
cc: William H. Clagett
Cliff Barrett, CREDA Executive Director
CREDA Environmental Studies Work Group
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415.329.2608 Fax
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415.329.2386
415.329.2608 Fax
Water-Gas-Wastewater
415.329.2387
415.329.2608 Fax
Resource Management
Resource Planning
415.329.2689
415.326.1507 Fax
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415.329.2241
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May 16, 1994

Mr. James Feider
Area Manager
Western Area Power Administration
1825 Bell Street
Sacramento, CA 95825

Dear Mr. Feider:

Thank you for the opportunity to provide the Western Area Power Administration (Western) with comments on the proposed Energy Planning and Management Program (EPAMP) draft Environmental Impact Statement (EIS).

Western is to be commended for continuing the development of the EPAMP program. We concur with the EIS findings that:

- Integrated Resource Planning (IRP) when coupled with maintaining longer contracts leads to environmental benefits. Together they foster the use of maximum customer efficiency.
- Maintaining longer contracts leads to more Western customer stability, and that stability leads to environmental benefits.
- Minimizing the amount of allocation withdrawal for a resource pool leads to environmental benefits.

THE CASE FOR LONG-TERM CONTRACTS

Significant reductions in environmental impacts (principally air pollution impacts from new powerplants that may be deferred) can be achieved if long-term (25-35 year) contract extensions in conjunction with integrated resources planning are put into place. On a Western-wide basis, the Draft EIS forecasts the reduction of more than 3,000 tons of SO_x in 2015. The key to these significant benefits is shown in the Draft EIS to be long-term contract extensions. In fact, the Draft EIS shows the environmental benefits to increase as the contract term increases from 25 to 35 years.

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Palo Alto, CA 94303

We believe the benefits may actually be far greater than predicted by the EIS as demonstrated below.

THE ENVIRONMENTAL IMPACTS OF THE LENGTH OF WESTERN POWER CONTRACT EXTENSIONS

Western resource allocations provide a crucial component in most preference utility resource portfolios. These allocations form a base to which the utility adds complementary resources (including DSM) to meet its particular needs. Utilities rely on the stability provided by long lived resources and contracts to optimize the balance of actions to best meet their customer end use needs.

The attached diagram illustrates the difference in prudent utility resource acquisition decisions (shown by square edged boxes) and resultant outcomes (shown by rounded edge boxes) under the cases of a Western decision to maintain or to shorten contract durations.

Looking at the upper branch of the diagram showing the effects of maintaining long term resource extensions to preference utilities shows clearly more beneficial impacts on the environment. These occur because the long extensions provide a stable resource base for customers and reduced planning uncertainty. This allows the planners to take a longer term view and focus more on helping customers rather than on short term institutional survival.

By contrast the lower branch of the diagram shows that short resource extensions, exposes Western customers to increased and more immediate uncertainty about levels and terms of upcoming renewals. This uncertainty undermines their ability to borrow money while it simultaneously pushes them towards making prudent decisions to hedge against Western contract renewal uncertainties by lining up additional resources to come on line at the time of Western contract expiration.

Since the utility would be unsure of whether it will actually need to operate the resource, it would hedge by acquiring supply resources that have lower capital costs and higher operating costs (typically fossil-fired generation). Simultaneously, the utility would tend to decrease its commitment to renewables, cleaner, more efficient technologies since these have the opposite attributes of higher capital costs and lower operating costs.

Three immediate advantages to long-term renewals are evident. First, there is a decreased need for large resource additions. Secondly, there is an increased ability to borrow. Thirdly, when a resource need is identified, there is more certainty that it will be operated and therefore a greater emphasis is placed on resources with higher fixed costs, i.e. renewables such as wind and solar.

The longer term utility planning focus associated with maintaining long term Western allocations, coupled with the decreased pressure on the utility revenues to fund hedging programs, allows the utility to focus on meeting customer end use needs with increased DSM activities and decreased supply side additions.

Short contract extensions will tend to force prudent planners using IRP techniques to develop more supply resources at the expense of customer efficiency programs and to degrade the quality of those supply resources compared to what is achievable by maintaining long term extensions.

These differences between long-term and short-term extensions were not explicitly modeled in the EIS. In fact, EIS modeling not only assumes nearly identical planner responses for both long and short extensions, it also assumes that planners would choose the same type of supply resources and implement the same levels of customer efficiency programs in both cases. Therefore, we believe that the benefits of long duration power contracts are significantly under-estimated in the EPAMP EIS.

It takes a long term focus to implement solutions with environmental benefits. It takes a long term contract to allow this long term focus.

MINIMIZE THE DILUTION OF THE WESTERN RESOURCE

Since the EIS concluded that larger allocation leads to improved environmental benefit we recommend that the "resource pool" (reduced allocations) be held to a minimum value (2 percent or less reduction of contract rates of delivery (CRD).

CHOICE OF ALTERNATIVES

In light of the EIS findings having identified that both increasing contract length and increasing the amount of contract allocations renewed lead to environment improvements, it appears to be worthwhile to examine an option that maximizes both of those beneficial terms and still leaves Western with limited gradual adjustment provisions for dealing with possible environmental mitigation and project reoperation issues. This thirteenth alternative of 98 or 100% reallocation and 35 or 40 years duration would be our preferred choice since it maximizes both customer stability and environmental benefits.

We appreciate the opportunity to provide these comments and look forward to implementing the EPAMP Program with Western.

Sincerely,

E. J. Mrizek

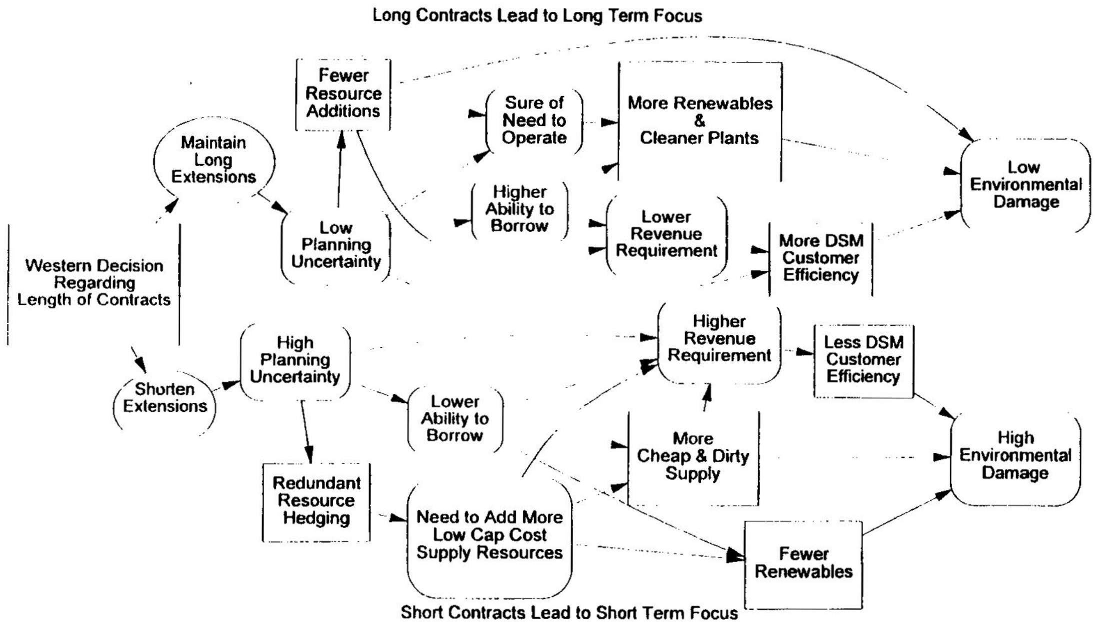
Edward J. Mrizek
Director of Utilities

EJM:tk:mv

Attachment

K2:epampeis.ltr

Prudent Responses to Length of Contract Extension



The CHAIRMAN. Mr. Graves.

STATEMENT OF THOMAS P. GRAVES

Mr. GRAVES. Thank you. My name is Thomas Graves; I am executive director of the Mid-West Electric Consumers Association. We appreciate the opportunity to come before the committee, and we especially appreciate Representative Johnson's arrival and remarks, and Mr. Allard coming here as well.

Mid-West is the regional association representing more than 300 member systems that serve some three million people in the upper Great Plains. The Pick-Sloan Missouri Basin program, as Tom Heller has noted, is an important if not critical resource for consumers in the upper Great Plains.

The advent of generation of power provided many rural electric cooperatives with their first power resource and enabled them to bring electricity to rural areas which investor-owned utilities were loathe to serve. For municipal electric systems and public power districts in the region, it provided a valuable alternative to construction of new plants.

Federal hydropower has provided a much-needed competitive "yardstick" for the consumer-owned utilities in the region to use in negotiations with other power suppliers for additional resources. Pick-Sloan Federal power customers, in fact, have already repaid some $893 million of principal, along with $852 million of interest and $1.86 billion in operations and maintenance costs.

The Pick-Sloan sales to Federal power customers are responsible for repaying 76 percent of the reimbursable costs to the Federal Government.

Mid-West supports the DEIS process that the Western Area Power Administration has embarked upon to implement the Energy Planning and Management Program. However, one must look at both sides of this program, both the power supply provisions of the power marketing initiative and the energy planning program.

The two program components are, in fact, interdependent, as they should be in an integrated planning approach. Effective and meaningful Integrated Resource Planning, or IRP, must include careful assessment of demand-side programs that might be used to meet future electric growth. That, in turn, dictates certain assumptions about the availability of existing resources.

Pick-Sloan customers have been particularly active in the demand-side area of resource planning. In 1984, East River put into place a demand-side program which allows them to control some 25 percent of their winter peak, some 80 megawatts are under demand control, and some 60 megawatts representing 20 percent of their system.

Throughout the Mid-West membership, a recent survey that we conducted shows that we have over 646 megawatts of load controlled in the summer season, representing 13.7 percent of total customer load in the region; and some 442 megawatts of control load in the winter season, representing some 9.5 percent of total load.

Those numbers will vary obviously from individual system to system. The Draft Environmental Impact Statement which Western has prepared for this program is not a perfect document, as Tom

Heller has noted, but it clearly demonstrates that the greatest environmental benefits will be garnered from the long-term contract extensions and preservation of a high percentage of existing customers' allocations.

Contracts for power in the Eastern Division will expire in the year 2000. In the Western Division of Pick-Sloan, which is generated at primarily hydroelectric projects on tributaries of the Missouri, those contracts expire in the year 2004.

Western's Pick-Sloan customers must know the status of their Federal allocations if they are to develop realistic and meaningful resource plans that look to the future. Without that information, the IRP process will be looking backwards, attempting to find replacements for existing Federal resources.

Given the very short time before the contract has expired, as well as the large percentage that Federal power represents in the customers' resource mix, the IRP process will inevitably lead customers to supply-side options to replace this existing power resource, if significant withdrawals are made or if there is a cloud of uncertainty over existing allocations.

To us, that would seem diametrically opposed to the intent of the legislation Congress passed two years ago. The IRP provisions of the Energy Policy Act of 1992 were enacted to encourage Federal power customers to engage in long-term planning for future resources that includes careful development of cost-effective demand-side measures that could be used as a part of a resource mix to meet future needs.

If, at the same time, Congress expects Western to withdraw a large percentage of customers' existing resource base, which the customer is using to serve existing load, the Congress is subverting its own legislative intent, since the customers will be focusing on the present situation, expending their energy and financial resources in a scramble to get back to square one.

To avoid that unintended result and to protect the beneficial environmental impacts, Mid-West supports the power marketing initiative that would provide customers with 98 percent of their existing allocations over a 25-year period. That would provide Western with 40 megawatts for the proposed resource pool.

Mid-West continues to support withdrawal provisions to accommodate changes in river hydrology or mandated operational changes such as those as we have already witnessed in the Missouri to accommodate threatened endangered bird species. We believe that the withdrawal provisions in Western's proposal, combined with the resource pool, will provide Western with the flexibility to market power to new representatives during this period and at the same time be sensitive to other demands, including environmental considerations.

Western's proposal will permit it to accommodate additional customers. In the Pick-Sloan marketing area, there are simply not that many new preference customers. There are no new rural electric cooperatives in the region. All rural electric cooperatives in the region do receive allocations of Federal power, either directly or through their generation and transmission member-based association.

There has been some municipalization of electric systems in some small towns in Iowa and Nebraska, but they are less than a dozen. The resource pool should be able to provide them with an allocation of Federal power and allow them to enjoy the benefits of the Federal power program.

Properly implemented, the resource pool can provide for new preference customers as well as mitigate changes in the hydro resource. Withdrawal of large percentages of existing customers' allocations could have negative impacts on Western's Pick-Sloan customers. Given the cost differential between Federal power and alternatives—be they demand or supply-side—greater withdrawals from existing customers would undoubtedly affect their rates and could even threaten their competitive position in the region.

Furthermore, since all Pick-Sloan customers would be affected by these withdrawals, withdrawals greater than 2 percent will undoubtedly affect the market for replacement power. Since this is a public program and a public process, the withdrawals will be a matter of public record, and that will certainly affect the system's ability to negotiate for new resources at a cost-effective price.

In summary, we support the Western program. We ask that it be allowed to go forward and extend contracts for existing customers while being sensitive to the resources that Western and the Federal Government needs for future conditions. We believe the Western program provides that kind of flexibility.

Thank you very much.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Graves follows:]

Statement of Thomas P. Graves, Executive Director

Mid-West Electric Consumers Association

before the

Oversight and Investigations Subcommittee

of the

House Natural Resources Committee

June 16, 1994

Mr. Chairman, My name is Thomas Graves. I am Executive Director of the Mid-West Electric Consumers Association. Mid-West is the regional coalition of consumer-owned electric utilities that purchase hydroelectric power generated at the federal multi-purpose projects in the Missouri River basin. Federal power is marketed under the Pick-Sloan Missouri Basin Program, eastern and western divisions. Founded in 1958, Mid-West's more than three hundred member systems serve over three million people in the upper Great Plains.

Mid-West appreciates the opportunity to come before the sub-committee to present its views on implementation of the Western Area Power

Administration's (Western) new program initiative, the Energy Planning and Management Program.

The Pick-Sloan Missouri Basin Program (Pick-Sloan) hydropower marketed by Western is an important, if not critical, part of the resource mix of consumer-owned utilities in the upper Great Plains. The advent of generation of federal power in the region, in fact, provided many rural electric cooperatives with their initial power resource and enabled them to bring electricity to rural areas, which investor-owned utilities were loath to serve. For municipal electric utilities and public power districts in the region it provided them a valuable alternative to construction of additional thermal plants. Federal hydropower also provided a much needed competitive "yardstick" for the consumer-owned utilities in the region to use in their negotiations with other power suppliers for additional resources.

For consumer-owned systems in the Missouri River Basin, federal hydropower represents anywhere from 30% to 50% of rural electric cooperatives' power resources, though there are some systems that receive less. For municipal electric systems, federal power accounts for about 65% of their resource, though there are a very few small towns where federal power accounts for 100% of their resource.

Western has chosen to separate the integrated resource planning program required in section 114 of the Energy Policy Act of 1992 into two components: the Energy Management Program (EMP), which provides for development of efficient demand-side programs by Western's customers, and the Power Marketing Initiative (PMI), which provides through the extension of power contracts continued availability of existing firm power allocations with those same customers. As we understand it, the purpose of this hearing is to discuss the power supply aspects of the PMI. Simply put, how much for how long.

However, one cannot properly analyze the PMI without understanding its impact on the other key program element, the EMP. The two program components are interdependent, as they should be in an integrated planning approach. Effective and meaningful integrated resource planning, or IRP, must include careful assessment of demand-side programs that might be used to meet future electricity growth. That, in turn, dictates certain assumptions about the availability of existing resources.

The Draft Environmental Impact Statement (DEIS) that Western has prepared for this program is not a perfect document, but it clearly demonstrates that the greatest environmental benefits will be garnered from long term contract extensions and preservation of a high percentage of existing customers' allocations.

Contracts for power from the Eastern Division of Pick-Sloan, which is generated at hydroelectric powerplants on the mainstem of the Missouri River, expire in the year 2000. Contracts for power from the Western Division of Pick-Sloan, which is generated primarily at hydroelectric projects on tributaries of the Missouri River, expire in 2004. Western's Pick-Sloan customers must know the status of their federal allocations if they're to develop realistic and meaningful integrated resource plans that look to the future. Without that information, the IRP process will be looking backwards, attempting to find replacements for existing federal resources. Given the very short time before the Pick-Sloan contracts expire, as well as the large percentage that federal power represents in their resource mix, the IRP process will inevitably lead customers to supply-side options to replace this existing power resource, if significant withdrawals are made, or there is a cloud of uncertainty over existing allocations.

That would seem to be diametrically opposed to the intent of the legislation Congress passed two years ago. The IRP provisions of the Energy Policy Act of 1992 were enacted to encourage federal power customers to engage in a long term planning process for future resources that included careful development of cost-effective demand-side measures that could be used as part of a resource mix to meet future needs. If, at the same time, Congress expects Western to withdraw a large percentage of a customer's *existing* resource base, which the customer is using to serve *existing* load, the Congress is subverting its own legislative intent, since customers will be focusing on the present situation, expending their energy and financial resources in a scramble to get back to square one.

To avoid that unintended result and to protect the beneficial environmental impacts identified in the DEIS, Mid-West supports a Power Marketing Initiative that would provide existing federal power customers with of 98% of their existing allocations. That would provide 40 megawatts for Western's proposed Resource Pool. Mid-West continues to support withdrawal provisions to accommodate changes in river hydrology or mandated operational changes, such as those we have already witnessed on the Missouri to accommodate threatened and endangered bird species, the piping plover and interior least tern. We believe that those withdrawal provisions, combined with the Resource Pool, will provide Western with the flexibility to market power to new preference entities during this period, and, at the same time, be sensitive to other demands.

A twenty-five year contract extension of 98% of the resource for Pick-Sloan federal power customers will not adversely affect Western's ability to adapt to new circumstances. As mentioned before, the withdrawal provisions Western has proposed will permit the agency to accommodate changes in river conditions or operations. Western's proposal will also permit it to accommodate additional customers. The Resource Pool which Western has proposed could be used to provide power to new preference customers. In the Pick-Sloan marketing area, there are not many "new" preference customers. There are no new rural electric cooperatives in the region. All rural electric cooperatives in the region receive allocations of federal power, either directly, or through their generation and transmission member-based associations. There have been some municipalizations of electric systems in some small towns; the Resource Pool should be able to provide them with an allocation. Properly implemented, the Resource Pool can provide for new preference customers as well as mitigate changes in the hydro resource.

Withdrawal of larger percentages of existing customers' allocations is not necessary, and could have significant impacts on Western's Pick-Sloan customers. Given the cost differential between federal power and alternatives -- be they demand or supply side -- greater withdrawals from existing customers would undoubtedly affect their rates and could even threaten their competitive position in the region. Furthermore, since all Pick-Sloan customers will be affected by withdrawals, withdrawals greater than 2% will undoubtedly affect the market for replacement power. Since this is a public program and the withdrawals will be a matter of public record, affected consumer-owned systems will be at a disadvantage when seeking resources to offset the loss of existing resources.

Western does not have utility responsibility for providing all the power needs of its customers. Western's responsibility is limited to the marketing and transmission of federal power generated at Bureau and Corps projects in the Missouri River Basin. Western currently markets some 10,500 GWh of firm power in Pick-Sloan, eastern and western divisions. Pick-Sloan has a capability of 12,000 GWh. From time to time Western does purchase power for the traditional firming of hydro resources or to offset adverse hydrological conditions such as those that have beset the Missouri River Basin recently.

We support that sort of activity; but we, as customers, are not interested in Western committing to marketing more power than the system generates. If Western were to make marketing commitments beyond the capabilities of the river, Western would continually have to purchase power from other sources to meet contractual demand. Since those purchased power costs would be rolled into the rates, they would soon drive up the rate for federal power to non-competitive levels. Frankly, we do not believe that Western is interested in over extending the resource it markets anymore than we are.

Mid-West supports twenty-five year contract extensions. For the electric utility industry, 25-30 year contracts are not unusual but customary practice, providing resource stability so that utilities are able to meet their utility responsibility, and assuring the financial arrangements to pay for resource acquisitions. Furthermore, customers need to be able to recover their investment in new resources. Shorter contract terms for existing resources will force customers to divert precious financial resources to finding power resources to meet existing load, diverting attention and dollars.

Electric generating entities using debt project financing typically contract to sell the output for the life of the plant. In essence, capital lenders require an electric utility to base its financing and financial calculations on the life of the plant. When the Rural Electrification Administration loans money to a generation and transmission borrower, REA requires the G&T to execute contracts with its distribution cooperatives to purchase the output of the power plant for the life of the facility, typically 35 years. The Federal Energy Regulatory Commission provides for 50 year licenses for non-federal hydroelectric development, assuring the licensee of fifty years of power generation. Congress recognized this need for a long term federal commitment in the Hoover Power Plant Act of 1984, which provides 30 year contracts for Hoover customers.

We recognize that all of these situations are not exactly analogous, but they do illustrate industry practice. Customers need that sort of certainty in order to rely the availability of their *existing* resources, which serve *existing* load, to be able to develop and implement integrated resource plans to address *new* load and *new resources* -- be they demand or supply side -- to meet that load. Otherwise, their plans for the future will be built on quicksand. Demand-side programs, in particular, take careful study, implementation, and monitoring if they are to be relied upon to increase the efficiency of existing resources.

The federal government also has an interest in long term contracts. Since federal power customers are the primary source of repayment of these projects, the federal government has an interest in insuring timely project repayment. Pick-Sloan federal power customers have already repaid some $893 million in principal, along with $852 million in interest, and $1.86 billion in operations and maintenance costs. In Pick-Sloan, sales to federal power customers are responsible for repaying 76% of the reimbursable costs. Shorter term contracts will require Western and its customers to spend inordinate amounts of time and money -- all of which will have to be recovered through rates -- in preparing and executing marketing plans. Preparing and implementation of a marketing plan can take as long as eleven years. Mid-West doesn't think those efforts and costs are necessary, given the flexibility Western's proposal already provides. In an era of reducing regulatory burdens and streamlining government, Western's time could be better spent reducing costs and designing rates that are sufficient to recover the federal investment while remaining competitive. That, in itself, is no small challenge.

In summary, Mid-West believes the program Western has proposed will best be served by long term contracts, twenty-five years, and an allocation of a high percentage of existing allocations, 98%. The Draft Environmental Impact Statement clearly demonstrates that that program approach provides the greatest environmental benefits. For Western's customers, it will provide some much needed stability as we enter into a dramatically changing and increasingly competitive electric utility industry. Western's customers will be able to focus their planning on the future, not the present. This is what we expect of a good Energy Planning and Management Program.

Thank you.

Mr. MILLER. Mr. Henderson.

STATEMENT OF JAMES HENDERSON

Mr. HENDERSON. Mr. Chairman, distinguished Members of the subcommittee, my name is James Henderson. I am the general manager of the Arkansas River Power Authority headquartered in Lamar, Colorado. I am currently serving as the president of the Loveland Area Customer Association, also known as LACA.

I am offering these comments today before the subcommittee on behalf of the Loveland Area Customer Association and Tri-State Generation and Transmission Cooperative, together referred to as the Loveland Area Projects Joint Customer Group. The LAP Customer Group purchases virtually all of the capacity and energy marketed by the Western Area Power Administration Loveland Area Office from the Loveland Area Projects, and we serve some 900,000 customers in the States of Colorado, Wyoming, Nebraska and Kansas. We purchase virtually all of the power marketed by Western's Loveland area office.

I would urge the committee to let WAPA proceed without delay in the development of the IRP program. This has been going on for several years now. We need to finalize this as soon as possible. Many of our members have already gone ahead and completed the IRPs.

My particular organization has not. For us, an IRP would represent about one-third of our total A&G expense. So when it is done, we have got to do it right the first time. We need, in order to do it right, to know what the rules will be. And for us to know the rules, you have got to allow WAPA to proceed.

LACA and Tri-State support a 25-year extension of the contracts, 98 percent allocation retention, and a small system provision. The customers desired stability in the resource; that is implied with a 25-year extension. The customers desired preservation of the resource; that is implied in a 98 percent allocation retention.

A long-term WAPA contract is critical to the goal of achieving the most effective IRP process possible. Why? Because if WAPA customers have the assurance of this resource, we can be much more aggressive with demand-side options. All demand-side options depend upon the utility's ability to influence the customer.

We do this through education. We do this through incentives. And we do this through rate signals. But the customer's response is somewhat unpredictable. They are human beings and individuals. It is also somewhat inconsistent over time.

We need the security of our Federal hydro resource so that if our demand-side efforts do not yield the results that we are seeking, we can keep the lights on, and this is the cornerstone of our power supply program.

Our long-term extension of our WAPA contracts will minimize the need for additional thermal resources. We believe this to be true simply because the less certain the Federal resource becomes, the more pressure there will be on people like myself to find some type of replacement resource. The likely result of that search will be more thermal resources with their associated environmental consequences.

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As I said before, many of Western's customers have already prepared IRPs on their own initiative. These studies have shown that most of the nonhydrorenewable resources are still not economically competitive with traditional thermal resources.

The important point that I am trying to make is simply this: As long as the Federal hydropower is delivered on a reliable basis, at cost-based rates, under long-term contracts, more effort and resources can be committed by Western's customers to the research and development of other renewables and to demand-side programs.

In conclusion, I would like to urge the subcommittee to allow the public process on the review of the EIS to proceed without delay. An effective integrated resource planning process coupled with long-term commitments to the Federal renewable resources is in the best interests, in my opinion, of the environment; in the best interests of the Federal Government; and certainly in the best interests of the customers that we serve.

A reliable, long-term Federal resource will promote effective renewable energy development and demand-side management. Additional fragmentation of the Federal resource will cause the need for construction, more thermal resources, and delay research and development of alternative power supplies.

We believe that effective IRP achieved with long-term Federal power contracts will enhance, not diminish, the value of the Federal hydro resource.

Thank you.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Henderson follows:]

Testimony of
James Henderson, President
Loveland Area Customer Association

for the Record of
the Hearing before the
U.S. House of Representatives
Natural Resources Subcommittee on Oversight and Investigations

Regarding the
Western Area Power Administration
Energy Planning and Management Program

June 16, 1994

Mr. Chairman and distinguished members of the Subcommittee, my name is James Henderson and I am the General Manager of the Arkansas River Power Authority in Lamar, Colorado. I am also currently serving as the President of the Loveland Area Customer Association ("LACA"). I present these comments today on behalf of LACA and Tri-State Generation and Transmission Association, together referred to as the Loveland Area Projects Joint Customer Group or the LAP Customer Group. The LAP Customer Group purchases virtually all of the capacity and energy marketed by the Western Area Power Administration (Western) Loveland Area Office from the Loveland Area Projects and we serve over 900,000 retail electric customers in Colorado, Wyoming, Nebraska, and Kansas. The LAP Customer Group has primarily been involved in the technical issues associated with the Loveland Area Projects but we find it necessary at this time to comment on the policy issues raised in the proposed Energy Planning and Management Program (EPMP). I have attached to my testimony a copy of our formal written comments which were submitted on May 13, 1994 in response to Western's Energy Planning and Management Program Draft Environmental Impact Statement ("EIS").

The development of Western's integrated resource planning (IRP) program has been going on for several years and we hope that it can be finalized soon so we can get on with the task of serving our customers. We understand that one of the primary issues of interest to the Subcommittee is the relationship between the extension of Western's long term firm power contracts and the promotion of an efficient and economical IRP process. We submit that the stability of the federal power resource and extension of the contract term have a direct relationship to effective IRPs because (i) it will improve the planning process, (ii) minimize the need for additional thermal resources and (iii) expedite the further development and implementation of renewable resources and demand side management (DSM) programs.

LAP CUSTOMER GROUP POSITION

The LAP Customer Group supports the 25 year contract extension and 98% allocation alternative with a small system provision. It is vitally important that the firm power contracts be extended as part of the IRP so that the resource plans can be properly coordinated and have a reasonable chance of being implemented. If the customers do not have a reasonable assurance of the availability of the federal hydro supply, then the long term plan may be in jeopardy. The more stable the supply-side resource, the more stable a utility's demand-side management program will be. This in turn will lead to increased efficiency in demand-side efforts and permit more planning resources to be committed to demand-side programs. This combination of long term contracts and IRP processes will provide a balance between the customers' desire for long-term resource stability and the Congressional goal of achieving quality in resource planning that meets the objectives of Section 114 of the Energy Policy Act of 1992 (EPAct). This also is consistent with the analysis in the EIS indicating that there are greater environmental and land use benefits which result from longer contract extensions and higher percentage of allocation. This alternative will provide greater accuracy and efficiency in long-term resource planning by non-federal entities and allow optimum integration of the present generation and transmission system with new facilities. Once the resources have been defined and a plan of implementation has been approved, the utilities can focus on issues such as expediting demand side management (DSM) programs. But if all the time is spent on studies and debates, implementation will be delayed.

A STABLE SUPPLY OF FEDERAL POWER IS ESSENTIAL FOR EFFECTIVE RESOURCE PLANNING

The federal hydropower marketed by Western is and has been the cornerstone of the preference customers resource development for the past forty years. Western's transmission system, in conjunction with the federally generated power, has been instrumental in the regionally developed, highly reliable electric power supply system serving the public in the western United States. The administration and operation of Western's electric system is vitally important to the future of the power supplying utilities and their customers. The economic viability of many rural areas depends on this system. Western's customers, not Western, have the ultimate obligation to provide reliable and economic service to retail electric customers. Western's customers prepare forecasts of the long term needs of their retail loads and operate their electric systems on a moment to moment basis to provide reliable electric service. When additional resources are needed, the preference customers make very careful decisions about the type, location, and timing of these facilities. They are very cautious when committing millions of dollars several years before the resource can actually be put into production. The scarce financial resources must be used wisely. A rigorous planning, siting, permitting, licensing, design, construction and testing process must be followed before power plants and transmission lines are put into useful service. It is not unususal for more than 10 years to elapse between initial concept and full utilization. On the other hand, customer loads can be developed and added to the system much more rapidly. Consequently, there exists a continual dilemma in the utility business about the timing of resource additions. When an existing resource is subject to major change (like some of the federal hydro projects), it is viewed as unreliable and additional resources may be needed to reliably meet the utility's delivery obligations. As the electric utility industry becomes more competitive, economic considerations become more acute. The stability and long term nature of the federal power resources is essential for effective long term planning.

WESTERN'S PRINCIPAL ROLE IN THE EPMP IS TO ENCOURAGE EFFECTIVE CUSTOMER IRP

Western is not a public utility charged with traditional utility responsibilities. Western is a marketing agency of federally generated hydropower constituting a partial resource for municipal, cooperative, and other preference entities. Traditional utility responsibilities include meeting customer load growth requirements. Western does not have this growth responsibility. Accordingly, to impose an IRP requirement on Western as some commenters suggest would only add a regulatory burden without corresponding benefits in light of Western's limited obligation. Under EPAct Western is charged with the responsibility for promoting and supporting its customers' efforts in IRP. We think this is the appropriate place for such planning to occur. Under this legislation, Western is not charged with the responsibility of preparing an IRP for its own operations. It should, however, continue to work jointly and cooperatively with the regional utilities to develop the most efficient, reliable, and economical system possible.

A LONG TERM FEDERAL POWER SUPPLY WILL ENCOURAGE DSM AND RENEWABLES

Western's customers have a long and active history of encouraging the wise use of electric energy and supporting the development of renewable resources. Many of Western's customers have prepared IRPs on their own initiative even before the passage of EPAct. These studies have shown that most of the non-hydro renewable resources are still not economically feasible when compared to more traditional power resources. For example, wind is not a reliable peaking resource because the wind does not always blow when the electric demand is highest. Wind may be a source of some energy, but without substantial advancement in electric storage technology, wind power may never be a viable peaking resource. Wind power also has its own set of environmental issues such as noise and land use. Much of the demand side management (DSM) and renewable resource options require extensive screening and analysis before substantial financial resources are committed. In many cases there are cheaper and more reliable alternatives available. Nevertheless, the preference customers have on their own initiative developed DSM programs, done screening studies, implemented DSM pilot programs and actively pursued and encouraged the wise and efficient use of this essential service prior to such programs being required by contract or law. However, the laws of physics, not the political laws or the level of effort or level of expenditures, will dictate the ultimate efficiency. Although some improvements can be made in more efficient use of electricity, most observers agree that DSM is not a "cure all" for increasing energy consumption. Most forecasters predict that energy use, particularly electric use, will continue to grow and even though new supply-side resources may be delayed, they will still eventually be needed. But the important point is simply this: As long as federal hydropower is delivered on a reliable basis at cost-based rates under long term contracts, more effort and resources can be committed by Western customers to research and development of renewable resources and DSM programs.

NEW CUSTOMER PREFERENCE STATUS SHOULD BE DETERMINED ON A PROJECT BASIS

Federal hydropower has been a material asset contributing to the economic growth and environmental quality of the West. The use of the natural energy available from water falling from 14,000 feet to sea level has been a critical factor in the development of the West. When these projects were conceived 30-40 years ago the preference customers "stepped up to the plate" and agreed to assist with the development of the hydro projects even though there were cheaper power sources available at that time. Nevertheless, we would not have a problem with considering allocations for Indian tribes who qualify as preference customers under the various marketing criteria. We would object, however, to taking substantial quantities of power away from the existing customers who have been participating all these years, just so other preference customers can now participate. Any adjustment to the current allocation should be done on a project-by-project basis according to the marketing criteria developed for that project. Inefficiency will result by dividing the available federal hydro resource into a large number of small allocations. Such fragmentation will diminish the benefits to existing customers while only marginally enhancing the power supply of the new customers. Most important, however, is the danger that resource fragmentation could lead to the construction of a larger amount of non-hydro fossil fueled resources, with their associated environmental consequences.

POWER IS PAYING MORE THAN ITS FAIR SHARE

The revenue from the federal hydro projects has been paying for a considerable portion of the infrastructure for the region. Not only are the power customers paying for the power features of the projects, they are paying for most of the irrigation costs. This provides, among other things, a base for the agriculture industry in the region and outstanding recreational opportunities both upstream and down stream which contribute to the regional economy. Power revenues therefore are paying for much more than the generation of electricity. They are supporting the economy and quality of life in the region. Additional subsidies by the power customers are not appropriate or necessary and must be discouraged. Users of the resources should pay their fair share of the benefits of the federal projects. Basic fairness dictates existing customers who have contributed to the repayment of the federal investment in direct power functions, shared the joint costs of multi-purpose projects, and subsidized other project users should have first call on extending contracts for firm power resources.

IRPs SHOULD NOT ENCUMBER THE SYSTEM RESOURCE PROCESS

Administrative and operational changes occurring within the federal electric system, such as the Glen Canyon EIS, the Salt Lake Area Marketing Criteria EIS, and the Upper Colorado Recovery Program, to name a few, have been very disruptive to the regional power system. The changes are making long-term planning more difficult and impeding the customers' planning process. Among the concerns are the level of detail for the IRP, compliance with IRP requirements of multiple jurisdictions, and the uncertainty in the amount and term of the contract rate of delivery. The IRP requirements should be made administratively simple to implement without sacrificing the goals of an IRP process.

TRANSMISSION IS VITAL TO EFFECTIVE IRPs

In order to investigate a full range of least cost options under the IRP process, Western's customers must have access to reasonably priced transmission service. Western's transmission system is a vital part of the regional transmission grid. It was designed to deliver hydropower to load centers to maximize the benefit of this renewable resource in the region. The generation and power transmission system in the West is planned and developed on a cooperative basis. The Federal Energy Regulatory Commission is also involved in addressing transmission access and pricing issues. Through such organizations as the Western Systems Coordinating

Council and the Inland Power Pool, data is exchanged, joint studies are done, and reports prepared and exchanged to develop the most efficient and reliable system possible. Individual entities have opportunity for input into the process and do have some discretion in their individual operations.

WESTERN'S POWER PURCHASES MAKE THE FEDERAL HYDRO RESOURCE MORE DEPENDABLE

Western is charged with the responsibility of maximizing the benefits of the federal hydropower system. It has been the responsibility of the Bureau of Reclamation and Western to determine the marketable resource from the hydro projects and then execute long term contracts for sale of the power. The "reasonable expectations" of the power customers is that the federal agencies will meet their long term contract obligations. Western is also authorized to purchase non-federal power that can be integrated with this hydro resource to optimize the system and maximize, to the greatest extent possible, the amount of federal power and energy that can be sold at the lowest cost firm power and energy rates. Western's thermal purchases are largely dictated by hydrology conditions below the "average" projected in the marketing plan. Therefore, some short term purchases are necessary. Customers are currently given the option of purchasing their own replacements but many customers need the assistance of Western in firming up their power supply. We would encourage Western to continue to allow the customers the option of supplying their own supplemental power or relying on Western. Short term purchases are negotiated on an individual basis and the terms of these arrangements can range from one hour to perpetual working arrangements. The uncertainty of the hydrology from year to year makes the purchase power decisions by Western particularly complex. Western needs to secure sufficient resources to meet their contractual obligations but also needs to be careful not to purchase more power than it can efficiently and economically use. These short-term purchase power decisions do not dictate the size, technology, timing, location or fuel input of power plants constructed or planned by non-Western power producers. Moreover, the approval of generating plant construction and operation by non-Western producers is subject to licensing, siting, environmental, and other regulatory approvals required under a variety of state and federal laws. Nobody is building power plants just to sell surplus power to Western. Moreover, in those years when the hydrological conditions permit, more federal power can be produced thus mitigating the need to burn fossil fuels. Future power plant construction in the Western U.S. will be subject to the application of IRP rules and regulations administered by the various state regulatory agencies, Western, and such agencies as the Rural Electrification Administration. Thus, the IRP and environmental factors will, in fact, be taken into account by the appropriate agencies having direct regulatory oversight over the non-Western power producers. These short term purchase decisions are not "ad hoc" but rather are consistent with standard utility practices.

CONCLUSION

I appreciate the opportunity to present these comments on behalf of the LAP Customer Group. We urge the Subcommittee to allow the public process on the review of the EIS and subsequent development of the IRP rules and regulations to proceed without further delay. An effective integrated resource planning process coupled with a long term commitment to federal renewable resources is in the best interest of the environment and the citizens who are also our customers. A reliable long term federal power resource will promote effective renewable energy development and DSM. Additional fragmentation of the federal resource will cause the need for the construction of more thermal resources and delay research and development of alternative power supplies. Effective IRP achieved with long term federal power contracts will enhance, not diminish, the value of the federal hydro projects.

We look forward to working with Western, the Department of Energy, and the Subcommittee in an effort to resolve in a timely manner the few remaining issues regarding the Energy Planning and Management Program.

LOVELAND AREA CUSTOMER ASSOCIATION

President - Jim Henderson - 719/336-3496
Vice Pres. - Mirek Horensovsky - 719/520-4020
Secretary - Larry LaMaack - 307/334-2170
Treasurer - John Allum - 303/229-5211

May 13, 1994

Mr. Bob Fullerton
Western Area Power Administration
P.O. Box 3402, A6100
Golden, CO 80401-0098

Re: Comments on the Western Area Power Administration Energy Planning and Management Program Environmental Impact Statement (EPMP-EIS)

Dear Mr. Fullerton:

The following comments are submitted by the Loveland Area Customer Association ("LACA") and Tri-State Generation and Transmission Association ("Tri-State") together referred to as the Loveland Area Projects Joint Customer Group ("LAP Customer Group") in response to the Western Area Power Administration's Energy Planning and Management Program Draft Environmental Impact Statement ("EPMP EIS") as published in the March 31, 1994 Federal Register. Together, the LAP Customer Group purchases virtually all of the capacity and energy marketed by the Loveland Area Office from the Loveland Area Projects. A list of the LAP Customer Group is provided in Attachment A.

Objectives

In the Purpose and Need Statement, Western cites the purposes of the EPMP EIS as:

- Promote the stable, efficient, and economical use of electrical generation and conservation resources by Western's customers.

- Promote consideration by Western's long-term firm power customers of cost-effective, demand-side management and supply-side alternatives including renewable resources, as part of their long-term planning process.

- Market Federal power on a long-term basis in accordance with Western's mission as a power marketing administration.

- Develop the Program in an equitable manner consistent with Western's legal obligations and constraints, including the obligation to carry out Section 114 of the Energy Policy Act of 1992.

We concur with the above stated purposes, but we would also add the following Objectives for Western:

- Assure a stable and reliable federal hydropower resource.

- Assure rate stability through commitments by Western and the operating agencies (U.S. Bureau of Reclamation and Corps of Engineers) to:
  (i). Hold normal operating and maintenance (O&M) expense increases below the rate of inflation.
  (ii). Institute a consultation process for meaningful customer input and review of O&M planning decisions.
  (iii). Continue to utilize cost based rate methodology.

- If the federal goal is to minimize adverse environmental impacts, then Western should hold down the rates of its renewable hydropower resources to reduce the need for customers to seek out alternative generation resources that may have more environmental impact.

- Provide flexibility to mutually agree and incorporate material changes in the federal hydropower marketing program through customer funding, joint participation, and other means intended to reduce program costs.

We feel strongly that these objectives are important to all Western activities and should especially be included in the EPMP effort to set the tone for the integrated resource planning (IRP) rules and regulations.

Background

The federal hydropower which is marketed by Western is and has been the cornerstone of the preference customers resource development for the past forty years. Western's transmission system, in conjunction with the federally generated power, has been the genesis of a regionally developed, reliable electric power supply system that serves the public in the western United States. The future administration and operation of that electric system is vitally significant to the future of the power supplying utilities and their customers. The economic viability of many rural areas depends on this system. Western, however, is not a public utility with traditional utility responsibilities. Western is a marketing agency of federally generated hydropower that constitutes a partial resource for municipal, cooperative, and other preference entities. Traditional utility responsibilities include meeting load growth requirements. Western does not have this growth responsibility. Accordingly, to impose an IRP requirement on Western in light of its limited obligation would add a regulatory burden without corresponding benefits. In the Energy Policy Act of 1992 (EPAct) Western was charged with the responsibility for promoting and supporting its customer's efforts in IRP which we think is the appropriate place for such planning to occur. Under this legislation, Western is not charged with the responsibility of preparing an IRP for its own operations. It should, however, continue to work jointly and cooperatively with the regional utilities to develop the most efficient, reliable, and economical system possible.

Most of Western's customers have a long and active history of encouraging the wise use of electric energy and supporting the development of renewable resources. Many of Western's customers have prepared IRPs on their own initiative even before they were required to do so by the effective date pursuant to EPAct. Much of the demand side management (DSM) and renewable resource effort is not easy to implement and in many cases there are cheaper and more reliable alternatives available. However, the preference customers have, on their own initiative, developed DSM programs, done screening studies, developed pilot programs and actively pursued and encouraged the wise and efficient use of this essential service prior to such programs being required by contract or law. The wholesale suppliers of electricity have limited opportunity for demand side efficiencies but, in close cooperation with their distribution members, they can accomplish the objective of the IRP process. However, the laws of physics, not the level of effort or level of expenditures, will dictate the ultimate efficiency. Thus the major effort for DSM will fall to the distribution entities, and with the encouragement of the wholesale supplier, will improve energy efficiency where appropriate.

Administrative and operational changes occurring within the federal electric system, such as the Glen Canyon EIS, the Salt Lake Area Marketing Criteria EIS, the Upper Colorado Recovery Program, to name a few, have been very disruptive to the regional power system. The changes are making long-term planning more difficult rather than easier, and impeding the customer's planning process. Among the concerns are the level of detail for the IRP, compliance with IRP requirements of multiple jurisdictions, and the uncertainty in the amount and term of the contract rate of delivery. The IRP requirements should be made administratively simple to implement and administer without sacrificing the goals of an IRP process.

The revenue from the federal hydro projects has been paying for some of the infrastructure for the region. Not only are the power customers paying for the power features of the projects, they are paying for most of the irrigation costs. This provides, among other things, a base for the agriculture industry in the region and outstanding recreational opportunities both upstream and down stream which contributes to the regional economy. Power revenues therefore are paying for much more than the generation of electricity, they are supporting the economy and quality of life in the region. Additional subsidies by the power customers is not appropriate or necessary and must be discouraged. The user of the resources should pay their fair share of the benefits of the federal projects. Basic fairness dictates that existing customers who have contributed to the repayment of the federal investment in direct power functions, shared the joint costs of multi-purpose projects, and subsidized other project users should have first call on extending contracts for firm power resources.

Western's transmission system is a vital part of the regional transmission grid. It was designed to deliver hydropower to load centers to maximize the benefit of this renewable resource in the region. The generation and power transmission system in the West is planned and developed on a cooperative basis. The Federal Energy Regulatory Commission is also involved in addressing transmission access and pricing issues. Through such organizations as the Western Systems Coordinating Council and the Inland Power Pool, data is exchanged, joint studies are done, and reports prepared and exchanged to try to develop the most efficient and reliable system possible. Individual entities have opportunity for input into the process and do have some discretion in their individual operations.

Western is charged with the responsibility of maximizing the benefits of the federal hydro power system. Western is also authorized to purchase non-federal power that can be integrated with this hydro resource to optimize the system and maximize, to the greatest extent possible, the amount of federal power and energy that can be sold at firm power and energy rates. Western's thermal purchases are largely dictated by hydrology conditions below the "average" projected in the marketing plan. Therefore, some short term purchases are necessary. Short term purchases are negotiated on an individual basis and the terms of these arrangements can range from one hour to standard working arrangements. The uncertainty of the hydrology from year to year makes the purchase power decisions by Western particularly complex. Western needs to secure sufficient resources to meet their contractual obligations but also needs to be careful not to purchase more power than it can efficiently and economically use. These short-term purchase power decisions do not dictate the size, technology, timing, location or fuel input of power plants constructed or planned by non-Western power producers. Moreover, the approval of generating plant construction and operation by non-Western producers is subject to licensing, sizing, environmental, and other regulatory approvals required under a variety of state and federal laws. Future power plant construction in the Western U.S. will also be subject to the application of IRP rules and regulations administered by the various state regulatory agencies, Western, and such agencies as the Rural Electrification Administration. Thus, the IRP and environmental factors will, in fact, be taken into account by the appropriate agencies having direct regulatory oversight over the non-Western power producers. These short term purchase decisions are not "ad hoc" but rather are consistent with standard utility practices.

Specific Comments on the Draft EIS

The LAP Customer Group concurs with Western's statement that:

> "Quality utility planning is enhanced when a customer's existing resources are stable and reliable. To be considered a stable and reliable part of a customer's existing resources, Western's power allocation must be secure over a time frame typical of long-term firm power sales and purchases in the utility industry."

The Draft EIS supports the conclusion that environmental benefits are maximized when existing contracts are extended for the greatest period of time at the highest percentage of existing allocation. The longer the contract extension period, the more continuity and "history" will be developed for existing customers to monitor, evaluate, and refine their IRP objectives and public participation processes. This will lead to better quality resource planning. The more stable the supply-side resource, the more stable a utility's demand-side management program will be. This in turn will lead to increased efficiency in demand-side efforts and permit more planning resources to be committed to demand-side programs. On the other hand, inefficiency will result by dividing the available federal hydro resource into a large number of small allocations. Such fragmentation will diminish the benefits to existing customers while only marginally enhancing the power supply for the new customers. Finally, any resource fragmentation could lead to the construction of a larger amount of non-hydro resources, with their associated environmental consequences, to meet the load growth requirements of Western's customers.

The LAP Customer Group acknowledges the broad basis of the EIS. This is a programmatic EIS rather than a project specific EIS and therefore it is hard to comment on specific issues. For example, the programmatic EIS assumes standard water quality and air quality conditions throughout the region when it develops comparisons of environmental impacts based solely on volume of water and air pollutants. Of course, conditions and impacts are not the same throughout the region, hence impacts may need to be refined on a project by project basis. Also, while there is a great deal of detailed data available on fossil fired generation, significant data is lacking for the alternative resources as shown in Table F1 in page 238. Also, Tables 4.1 (page 75) does not have complete data for such things as airborne water from cooling towers and ash from wood waste biomass. Therefore, it is difficult to make a definitive comparison of the alternatives. We generally agree however that the issues such as transmission access, rate design, river and dam operation, ecological and recreational resources, conservation purchases by Western, and project use efficiency are beyond the scope of the EIS at this time. We also agree that there is not adequate scientific data to justify the quantification of environmental externalities in resource decisions as described on pages 6 and 7 of the EIS and the public debate should continue on the issue.

Preferred Alternative

The LAP Customer Group generally supports Alternative 8 (25 year contract extension and 98% allocation) with some conditions. It is vitally important that IRP requirements be linked to the extension of the firm power allocation under reasonable conditions. This combination will provide a balance between the customers desire for long-term resource stability and the Congressional goal of achieving quality in resource planning that meets the objectives of Section 114 of the EPAct. This also is consistent with the analysis in the EIS that indicates that there is greater environmental and land use benefits which result from longer contract extensions and higher percentage of allocation. This alternative will provide greater accuracy in long-term resource planning by non-federal entities and allow optimum integration of the present generation and transmission system with new facilities.

All contracts,on a project by project basis, should terminate at the same date and the customers will still have the right to cancel the contract under Article 11 of the General Power Contract Provision (1/3/89 version) in the event that the rates become intolerable. We would suggest that Western also consider a provision which would allow additional rolling twenty five year extensions at the customers option when subsequent IRPs are submitted to Western.

The 2% resource pool created by the 98% of current allocation formula should be used for new customers only, and to the extent not used, it should be re-allocated back to the then existing customers. The resource pool should not include competitive incentives for IRP program compliance since the guidelines for such incentive are very difficult to establish and evaluate and they increase the uncertainty of the federal resource. If there is a reduction in the federal resource, the resource pool should be used for any adjustments prior to any reduction of allocations from existing customers.

At least five years notice should be given for any proposed adjustment to the firm power allocation during the contract period. These adjustments in the federal generation resource pool should only be implemented when there is a clear mandate, through statutes where possible, and only when the natural hydrology and the "Law of the River" dictates that the change is necessary. Changes in the federal resource allocations will mandate changes to the non-federal resources over a broad geographic area. This circumstance causes significant disruption in planning for and operation of the regional electric system, not only to Western customers, but also to other system participants. The mitigation of these changes takes time to develop and implement. Any change in allocation is predicated upon the explicit requirement of limiting adjustments due to river operation to those that make Western's resources as firm as possible, while reducing the need for firming purchases.

The LAP Customer Group would support the development of less stringent rules for the smaller electric systems who have annual loads of 25 GWH or less. These smaller systems usually rely on a larger system for their major planning requirements and do not have the staff or financial resources to conduct and implement extensive programs. The impact of this reduced program on the overall EPMP program will be minimal and reduce the administrative costs to both the customers and Western. The compliance for the smaller systems should also be based on an evaluation of their total energy picture not just their allocation from Western. Some of the small systems may need assistance in developing energy efficiency programs. Western should assist these smaller systems as appropriate, but the cost associated with providing the consulting service by Western should be reimbursed by the customer using the service not from the general rate base.

Western's acceptance (or rejection) of an IRP submitted by a customer must be based on the customers compliance with a well defined process and specific customer goals. Western should not assume any regulatory or judiciary authority over the plan but rather focus its role on administrative review of the submitted IRP plan to assure appropriate recognition of the planning criteria listed in Section 114 of the EPAct. We believe this is consistent with the Congressional intent. We understand that the Administrator of Western has the authority to rule on IRP compliance, however, we believe that the process should provide for a dispute resolution consultation process to allow for further clarification of issues and alternatives contained in the IRP. The rules of the Alternative Dispute Resolution Act should be considered. The EPAct provides that the Administrator shall accept the IRP which a customer has prepared in response to another state or federal IRP requirement which substantially complies with EPAct requirements. Therefore, Western's proposed IRP rules should recognize an IRP requirement by another jurisdiction. To avoid confusion, and minimize conflicting requirements with other jurisdictions, the proposed rules should not list specific requirements but should only deal in generalities with the seven elements enumerated in EPAct. If methodologies which require lengthy lead times are required (e.g. end-use load forecasting), they should be required in the second round of IRP filings. Also, if Western plans to adopt stringent requirements for each element of EPAct, Western should provide that any such requirements should not apply to any customer who is required to meet the requirements of a state or other federal agency which addresses the elements of EPAct. Governing body review and approval of a customer IRP should be sufficient to comply with the public process. The existing customers should have the first right (on a pro rata basis) to any unallocated power resulting from the reduction in allocation or a penalty.

In addition to a stable power supply resource, a stable cost of service rate is also imperative in order to avoid excessive cost swings and to minimize retail rate adjustments. The LAP Customer Group is encouraged by Western's recent activities towards these ends by its initiative to develop a process with its customers to adopt a cost review and containment program.

The rules and regulations should only apply to the contracting entities and should not automatically apply to all recipients of federal power. The rules should be flexible enough to accommodate regional and project specific differences and the rules should allow the existing joint action agencies and G&Ts to be eligible for the extension of time for filing the initial IRP as a cooperative agency (page 195).

The LAP Customer Group appreciates the opportunity to comment on the Draft EPMP EIS and Western's attempt to balance public policy direction with its customers needs. The federal system is the largest single power and transmission resource to millions of people in the West and therefore the actions that Western implements have far reaching consequences and should only be initiated with complete understanding and support of the public it serves. We encourage Western to work closely with its customers in implementing these initiatives. We understand that proposed rules and regulations are being developed for the EPMP program and these rules and regulations will be available in June 1994 for review and comment. We are very interested in seeing the proposed rules and regulations as soon as possible and we will be actively participating in the public process on these rules.

Loveland Area Customer Association

Jim Henderson, President

Tri-State Generation & Transmission Assoc

Frank Knutson, General Manager

cc: Steve Fausett

ATTACHMENT A

Loveland Area Projects Customer Group
(LAP Customer Group)

Tri-State Generation & Transmission Association, Inc.
Denver, CO

Loveland Area Customer Assoc. (LACA)

Arkansas River Power Authority
Lamar, CO

Center Municipal Light & Power
Center, CO

Municipal Subdistrict NCWCD
Loveland, CO

Kansas Electric Power Coop.
Topeka, KS

Willwood L&P Company
Powell, WY

Colorado Springs Utilities
Colorado Springs, CO

City of Gillette, WY

Town of Julesburg, CO

City of Wray, CO

Town of Haxtun, CO

City of Alliance, NE

City of Sidney, NE

Wyoming Municipal Power Authority
Lusk, WY

Platte River Power Authority
Ft. Collins, CO

Nebraska Public Power District
Columbus, NE

Intermountain REA
Sedalia, CO

Municipal Energy Agency of Nebraska
Lincoln, NE

Denver Water Board
Denver, CO

City of Ft. Morgan, CO

City of Yuma, CO

City of Gering, NE

City of Holyoke, CO

City of Burlington, CO

Mitchell Utilities
Mitchell, NE

Mr. MILLER. Ms. Schori.

STATEMENT OF JAN SCHORI

Ms. SCHORI. Thank you. I am the relatively new general manager of the Sacramento Municipal Utility District. Thank you and the members of the subcommittee for allowing us to testify this morning.

We serve about a million people. We have a 900-square-mile service area. We serve the State capital in California. We have a very big stake in the discussions that are under way here because we are Western's largest customer.

We may also be one of the municipals with the most extensive experience in integrated resource planning, as a result of the decision of our voters in 1989 to close the Rancho Seco nuclear power plant. We had a very big opportunity and we took advantage of it. We went into a full, integrated resource planning effort, and as a result of that, SMUD has doubled its commitment to DSM-type programs.

We also have a large renewable commitment and we are developing four cogeneration power plants right now.

We think integrated resource planning works, and we are a very big supporter of it. The Western power allocation we receive is a very large component and an essential building block of our integrated resource plan.

This morning I wanted to address what I think are the principal concerns that have been expressed by the committee: long-term contracting extensions and the timing of the process now under way at Western.

I would like to make four points in response to these concerns. First, I don't think it has been mentioned here, but really power contracts historically have not been like water contracts. They have been flexible; they have been adaptable. The committee, the environmental community, the power customers and Western have been successful in addressing concerns about the environment, concerns about the need to adapt the operation of the facilities, and we have been able to work through those kinds of issues in the past. I don't see any reason why there should be concern that we wouldn't be able to address those issues in the future as well.

We do think that by maintaining a fairly flexible definition of available resource in power contracts, we can adapt the contracts to future needs as all parties will feel necessary.

The second point, and I think this one is pretty essential, is that long-term power contracts really are essential to support the development of renewables and demand-side management techniques. I wanted to mention this morning SMUD's new marginal cost study, because I thought maybe this would just be useful to give you some actual numbers of how WAPA power is now stacking up against the cost of other resources. We just published it this week with our own board.

First off, I will tell you, these are all 1995 projections, in the 20-year marginal cost study, and we are using 1994 real dollars, which means they do not reflect inflation.

The WAPA power is coming in at 3.1 cents. Gas-fired resources, natural gas-fired resources in our study are coming in at 3.5 cents.

Wind and biomass are coming in around 5 cents. Assuming we can get the cost down as hard as we are trying to over the next 20 years, the low settlement on PBs is 6 cents and the high estimate is 14 cents. And all of the technologies we have been examining, there is the greatest uncertainty right now in the numbers that we see coming out for the projections on PB systems.

Finally, I thought I would throw out solar-thermal, since SMUD is looking hard at a solar-thermal plant to take advantage of the land and facilities we have at Rancho Seco. Our low estimate on 20 years is 8 cents and the high estimate is 10 cents.

I think the point I want to make this morning is that running a utility has to be like a business. We have to look at what our options are. We have to try to hold the cost down to keep the rates as low as we can for our customers.

So price is a very important factor when we are trying to pick the resources that will be available to us in the future, and we think that there are some really creative opportunities that could be available with WAPA power. In particular, we see it supporting renewables that are big on energy and low on capacity, because obviously the CP system in California has a very large capacity of resource. It makes an excellent match with wind, which is good on energy and not so good on capacity.

But for us to get the price of those renewables down—and I am just giving them to you—we are going to have to average in the cost of lower-cost resources in order to defend making a commitment to the renewable resources that we are showing in our resource plan.

We think that developing long-term contracts helps support the advancement of renewables. We are going to have to finance those projects over a 20- to 30-year commitment. It is very hard to defend the cost of them for 20 years if you can't back them up and show that you have got some lower cost resources to balance out the overall cost.

So we do think that going forward with long-term contracts supports the policy goal that this committee has of renewables and energy efficiency.

The third point I wanted to make is that the contracts in California expire in 2004. So from our perspective, it is critical to start moving now. We intend to do an RFP for renewables in 1996, and we need to have some idea what the policy direction will be on allocation of Western resources.

Finally, the fourth point, we support project-by-project resource evaluation. We don't think one-size-fits-all works. We do not support resource pool withdrawals. We think that there would be impacts as the customers try and examine replacement resources, and the need hasn't been demonstrated yet.

We support retention of allocations, intention upon meeting energy efficiency and renewable goals, and we recommend that new customer needs be handled on a case-by-case basis in each area.

Thank you very much.

Mr. MILLER. Thank you.

[Prepared statement of Ms. Schori follows:]

TESTIMONY OF JAN SCHORI,GENERAL MANAGER, SACRAMENTO MUNICIPAL UTILITY DISTRICT, AT THE HOUSE NATURAL RESOURCES SUB-COMMITTEE ON OVERSIGHT AND INVESTIGATIONS HEARING ON MARKETING OF FEDERAL POWER BY THE WESTERN AREA POWER ADMINISTRATION
June 16 1994

Introduction

Thank you very much for the opportunity to provide input to the Committee's hearing on the Western power marketing issues before you today, from the perspective of a large consumer-owned utility customer of Western. The Sacramento Municipal Utility District is Western's largest customer, and has purchased firm power from the Central Valley Project for over 40 years. This firm supply of power is purchased at cost based rates by SMUD and provided without profit to over one million people in central California.

The Western resource has been a source of stability and efficiency to SMUD, and as such has helped SMUD become an industry leader in demand side management and renewable resources. SMUD's resource planning goal is to meet load growth through the year 2000 with demand side measures, and achieve a resource portfolio with 60 percent renewable resources and energy efficiency by 2004. These renewable resources are capital intensive and are often amortized over the longest possible term to bring annual costs down, but they remain more expensive than conventional powerplants. Continued availability of a stable and cost effective Western resource, now costing about three cents per kilowatthour, allows the five to seven cent renewable and demand side resources to be more affordable, compared to natural gas generation, costing around four cents per kilowatthour.

SMUD plans to issue a request for proposals by 1996 for renewable resources to meet load through 2020. It is critical that SMUD knows if Western's power is available in long term contracts. Without the certainty that the operational and economic benefits of Western power will be available, SMUD will have difficulty constructing more wind, solar, and other renewable resources so we can meet our commitment to reduce greenhouse emissions and achieve the goals of the Administration's program on global climate change.

SMUD views Western power as a source of substantial benefit, not only to the consumer owned utility customer, but to the nation as a whole. It is the power revenues from the Central Valley Project that are the principal source of repayment of $2 billion of federal taxpayer investment in the CVP. And millions of dollars of power revenues from consumer owned utilities are supporting the environmental restoration authorized by the CVP Improvement Act.

Clearly taxpayers and the environment also have a stake in the continued viability of Western's power marketing program.

As I understand it, the question before the Committee is "Does the Energy Planning and Management Program as proposed, appropriately guide Western's power marketing program?". The Committee has specific concerns regarding timing of the process, the level of commitment, and the distribution of benefits from federal power.

SMUD Supports Energy Planning and Management Program Concepts

SMUD supports the concept behind Western's Energy Planning and Management Program, that integrated resource planning and long term contracts will help maintain stability in customer resource planning. As the Chairman knows, SMUD supported his legislation, which became part of the 1992 Energy Policy Act, requiring Western customers to adopt integrated resource plans. By initiating policy decisions on Western power marketing plans early, Western facilitates integrated resource plan preparation, and reduces uncertainties in the planning process, even if some resource uncertainty remains.

Timely Allocation Policy Decisions are Critical to Customer Planning

It is not too soon to initiate the decision making process for the Sacramento Area Office. Current contracts in northern California expire in 2004. By initiating policy decisions on marketing in 1994, through both the Energy Planning and Management Program and the 2004 Marketing Plan, criteria for allocation of the available resource should be set by 1997. Responsible acquisition of replacement resources can take six to ten years to plan, license, design, and build, so as much knowledge about Western allocations as possible is needed by 1996 or 1997. At least in the Sacramento Area, allocation decisions need to begin now, in order for SMUD to efficiently plan a resource portfolio for the next 25 years.

Avoid Compounding Resource Uncertainty with Policy Uncertainty

Questions have been asked regarding the real value of contract extensions when the availability of the hydro resource is uncertain. Federal hydroelectric resource uncertainty is a risk utility customers have been managing for some time. It can be managed with proper planning, with other contracts and support resources. Western's power marketing program addresses the issue of resource uncertainty by proposing to renew a "percentage of available resource", as opposed to a percentage of the current allocation. The available resource should be determined in cooperation with the Bureau of Reclamation on a project by project basis. Compounding this resource uncertainty with no timely decision on allocation policy issues would make integrated resource planning by power customers even more risky. Further uncertainty will undermine our ability to continue investing in energy efficiency and renewable resources. And it will jeopardize the contribution of Western's customer base to the environmental mitigation and project repayment now required by law.

Power Contracts Do Not Constrain Central Valley Project Operation

Concern has been expressed about locking in power allocations and constraining operations at federal dams. Western, Reclamation, and preference customers all understand that power generation at Reclamation projects has been and must continue to be adaptable to reservoir operations that must respond to changing demands for flood control, navigation, irrigation, fish and wildlife demands, and municipal and industrial demands. Changes in Central Valley Project operation mandated by the CVP Improvement Act were not constrained by power contracts, and no contract changes were required in response to that Act, which SMUD also supported.

Long Term Contracts of 25 Years Facilitate Customer Investment in Renewable and Demand Side Resources

Western contracts must have terms of 25 years to be commensurate with other competitive resources, and to support customer acquisition of resources which are environmentally responsible and economically sustainable. SMUD's experience has been that a diversified, renewable resource plan relies on resources that require longer financing terms and complex coordination with community needs. A long term Western contract, for cost based power with the capacity and operational attributes of hydroelectric resources, provides the economic and operational ability for Western customers to develop renewable and demand side resources.

For example, when SMUD shut down a 900 MW nuclear powerplant in 1989, we negotiated relatively short term purchase contracts (five to ten years in length) with adjacent utilities. These contracts rely on operation of existing and relatively inefficient thermal plants with associated environmental and economic costs. They provide a bridge to building a more sustainable resource portfolio with more benefits to the community and the environment.

During the 1996 to 2004 time frame, SMUD is replacing these purchases with 500 MW of cogeneration, 350 MW of renewable resources, and 350 MW of energy efficiency. But these types of projects require financing over 20 to 30 years so that the higher fixed costs can be spread over enough time to keep rates competitive. A stable and economic Western allocation has helped make it economically possible for SMUD to acquire the solar, wind, and demand side resources, as well as advanced gas fired cogeneration projects which attracted or retained substantial jobs and tax base in Sacramento.

If the Western resource is available over a similar time frame, the flexibility and responsiveness of the Western hydroelectric resource can support renewable resources like solar and wind projects, which are often energy rich, but lack firm capacity and operational responsiveness. Increased operational coordination between customer-owned renewable resources and Western hydro resources could provide substantial benefits. For example, energy from an additional 50 MW wind plant could be combined with capacity and spinning reserve from Western to create a mutually beneficial resource. If Western power is available only for shorter terms, and with less lead time, customers must rely more on conventional thermal powerplants and purchases which make economic sense in the short term.

Evaluate Resource Availability and the Need for New Customers on a Project by Project Basis

SMUD also believes that the proposal to withhold a percentage of the Western resource in a resource pool would not advance accomplishment of the planning and efficiency goals of the Energy Planning and Management Program. Some have suggested that a withdrawal of 30 percent of the available resource is appropriate. In the Sacramento Area, a 30 percent withdrawal would withhold over 400 MW. This would trigger customer resource replacements with attendant environmental and economic impacts, all for a need that is not established.

Rather than withdraw a percentage of available resource from all customers power into a generic resource pool, SMUD suggests that resource availability and new customer needs be evaluated on a project by project basis. Where a Western identifies a compelling public benefit would be met by a new customer allocation, the remaining "available resource" will reflect Western's decision.

Customers Should Retain Share of Available Resource Contingent on IRP Performance, Rather than Compete for Reallocation from a Resource Pool

All customers should be given the opportunity to retain their full percentage of the remaining available resource, subject to meeting minimum Western standards for energy efficiency, and selection of renewable resources (when needed) as specified in the IRP's. This approach is more positive, and would be more equitable than a withdrawal and reassignment approach.

Western Transmission Can Increase Customer Efficiency and Reduce Environmental Impacts of Customer Operations

The value of Western's transmission system to customer efficiency cannot be overlooked. The efficiency benefits of diversity between the loads and resources of various customers and regions can only captured if cost effective and reliable transmission access is preserved. Western's aggressive participation in the California-Oregon Transmission Project was instrumental in completing this important link between California and the Pacific Northwest. Looking to the future, diversity opportunities exist between the California and the southwest states as well. Peaking capacity on the Colorado River system is being reduced, while in the Sacramento River system, winter energy and energy shaping will be reduced in 2004 due to a contract expiration. Transmission linkage between the regions could allow a diversity exchange to meet both parties needs, without each having to separately acquire duplicative replacement resources. But transmission additions for efficient planning are capital intensive, and these costs must be spread over 25 to 30 years to be economical. Long term Western contracts at cost based rates facilitate prudent resource decisions providing long term benefits.

Conclusion

In conclusion, SMUD believes that the Western resource remains a valuable base for integrated resource planning by Western customers. But in order for preference power customers like SMUD to continue remain competitive while making investments in renewable technology, and continue funding environmental improvements like the CVP Restoration Fund, we need long term firm contracts for federal power at competitive, cost based rates. Western needs long term revenue certainty from these full cost rates to repay taxpayer investment in Reclamation projects as provided in Federal law. Proposals to move away from this cost based system ignore the documented benefits of this long standing policy to the taxpayer, the customer, and now the environment. Short term contracts, allocation uncertainty, and deviation from cost based rates would expose non-profit preference customers and the federal government to unnecessary and imprudent risk in the future. Thank you for your time. I am available to answer any questions you may have.

Mr. MILLER. Mr. Martin.

STATEMENT OF THOMAS S. MARTIN

Mr. MARTIN. Mr. Chairman, members of the subcommittee, thank you for the opportunity to appear before you today. My name is Thomas Martin; I am the general manager of Electrical District No. 2 in Pinal County, Arizona.

We kind of represent the other end of the spectrum from SMUD. We are a small, rural, publicly owned electric distribution utility with no generation, located midway between Phoenix and Tucson. We serve approximately 3,000 customers in an area encompassing about 100,000 acres.

Like many public power districts and cooperatives, the district was formed to bring electric power to rural areas largely because the investor-owned utilities of the day didn't find it profitable to do so. The availability of cost-based Federal hydropower has been the lifeblood of many small municipal and rural electric systems such as ourselves.

Our interest in being here today stems from concerns about the future availability and price of this power. Pinal County, the area in which we serve, is one of the poorest counties in the State. The electric bill for many of our customers represents a major portion of their monthly budget.

We recognize that the Federal power system has been used to further social goals and that these goals may change from time to time. However, our customers simply can't afford higher rates that will inevitably result from the reductions in the availability or artificial increases in the price of Federal hydropower resources.

To put this in perspective, hydropower supplied 50 percent of the district's needs in 1993. We are also dependent on Federal transmission to obtain the remainder of our power resources. Integrating the resource planning is vitally important for us from a purely business standpoint. It only makes sense to try and control the largest segment of our cost of service.

Reducing the term of future contract renewals or reductions in the amount of resources that are allocated to existing customers will make effective resource planning much more difficult and will translate into higher costs. The reason is that utilities must be prepared to meet loads as they appear. While cost-effective load management can help reduce peak loads, it can't be used to generate power.

Uncertainty about the availability of resource leads one to forsake the uncertain resource for one having a more assured availability, even if it is more expensive. A good example of the potential price uncertainty is the Salt River Project's exchange agreement with Western. Through this agreement—which, by the way, has a contract term of 40 years—Salt River's thermal plants in Colorado were used to supply power to some of Western's customers in Colorado and Utah.

In return, Western provides power from Grand Canyon and Salt River. Lack of certainty about the future availability of generation from Glen Canyon may require the investment of millions of dollars to build capacity that previously wasn't needed.

ED–2 has been a district for 70 years. I would like to think it will be around 707 years from now. I don't believe small public power systems are anachronisms today. We know our customers, in many cases, by name. Our small size makes it easier for us to try out new ideas and abandon those that don't work.

In conclusion, Mr. Chairman, I believe we are at a crossroads here. Tampering with the process that Western has used in the past to set allocations in contract durations will likely increase the costs for us. These cost increases may ultimately drive us out of business. I hope, Mr. Chairman, that the outcome of this hearing does not lead to a more uncertain future for Western and its customers.

Thank you very much.

[Prepared statement of Mr. Martin follows:]

Before the House Committee on Natural Resources

Subcommittee on Oversight and Investigations

Testimony of
Thomas S. Martin, General Manger
Electrical District No. 2, Pinal County, Arizona

June 16, 1994

Dear Mr. Chairman and Members of the Committee:

Thank you for the opportunity to present the views of Electrical District No. 2 on the subject of the draft EIS prepared by Western Area Power Administration (Western) pertaining to the future allocation of federal hydroelectric power.

I am the general manager of Electrical District No. 2 (ED2) of Pinal County, Arizona. ED2 is a small, rural, publicly-owned electric distribution utility serving approximately 3,000 residential and other customers, located in south-central Arizona, midway between Phoenix and Tucson. ED2's principal customer base is centered on agriculture, though we serve residential, commercial and a few industrial customers. In this respect, ED2 is representative of a large number of Western's rural electric and municipal customers who provide electric service to relatively sparsely populated areas throughout the West and Midwest.

ED2 was incorporated in 1923, and its first lines were energized in 1927. Like many public utility districts and electric cooperatives, ED2 was formed to bring electric service to rural areas which were considered by the investor-owned utilities of the time to be too expensive to serve. The availability of preference power from federal hydroelectric projects has been the lifeblood for many small utilities such as ourselves. The higher per capita investment to serve our sparsely populated service areas, compared to the more densely populated urban areas, already results in higher rates for rural consumers. Without reasonably priced preference power, this rate disparity will only grow larger.

Equally important is the per capita income differential between most urban and rural areas. Pinal County, Arizona is one of the poorest counties in the state. Many of ED2's customers receive various forms of public assistance and money from private charities to pay their electric bills. Many of our customers are transient and live in public housing projects or in mobile homes. These families do not have the incomes to invest in various home improvements and new higher efficiency appliances to reduce their utility bills. Consequently, the higher rates that would inevitably result from changes in the availability or pricing of power from federal hydroelectric projects would magnify the problems already faced by many of our customers.

Western, in developing the criteria embodied in its Energy Planning and Management Program (EPAM) has produced a detailed approach to long-term planning which considers end-use load forecasting, demand-side management programs, and evaluation of renewable resources, as well as the more traditional power supply generation and purchase options. We support the process developed by Western as a requisite to receiving future allocations of power from the projects it markets. However, we also expect that these future allocations will be largely consistent with current contract terms.

In reviewing comments on Western's draft EIS for its EPAM program, it is evident that some parties do not believe that it is necessary for Western to make a long-term contract commitment for the resources it allocates among its customers. It appears that there is controversy regarding how much of the existing hydroelectric resource should be reallocated in order to allow an allocation for new preference entities and accommodate changes in flow regimes resulting from various regulatory and environmental considerations.

I would like to address first the issue of length of contract extensions. The electric utility industry is characterized by high cost investments in generation and transmission facilities. In most cases, these facilities have service lives of 30 years or more. Hydroelectric facilities are frequently associated with 50 year service lives. It would be imprudent for utilities to invest the necessary capital to build such facilities if there is no certainty that the resource will be fully available for these periods of time. However, this is exactly what proponents of short contract extensions are expecting us to accept if the capacity associated with federal power contracts is not available for a sufficiently long period of time. Obviously, investor-owned utilities which have their own generating resources and extensive transmission networks have greater flexibility to absorb fluctuations in federal power contracts. They have other resources to back them up and the percentage of their power supply associated with federal hydroelectric power is relatively small by comparison with their total pool of resources.

In the case of small distribution entities, such as ED2, which rely completely on purchased power contracts for their power supply (and for whom federal hydropower represents a significant portion of their total available resources), such uncertainty would be devastating. To be more specific, in 1993 federal hydropower provided 60 percent of ED2's energy needs and 50 percent of our total capacity.

Like our larger brethren, we have a duty to provide reliable, reasonably priced electric service to our customers. If the contract period for federal hydropower is too short, contractors may find it necessary to overcommit to replacement resources, increasing the costs of a utility's power supply. Most small utilities that receive federal power also purchase supplemental power from other sources. The long-term nature of federal power contracts has provided smaller utilities with some leverage in contracting with these supplemental power suppliers. The reason for this is twofold. First, the federal power contract acts as the cornerstone for building our overall power supply plan. It is much easier to deal with other suppliers if you know in advance what the federal hydroelectric supply will look like and how long it will last. It is difficult to predict load growth with a reasonable degree of accuracy without compounding the difficulty by not knowing how long your largest resource will be available.

The second aspect of the leverage a known long-term contract with Western provides concerns the type of supplemental resource for which one is contracting. In most circumstances it is less expensive per kilowatthour to purchase base load (i.e., high load factor) blocks of power than to purchase power for peaking purposes. This is because of the low utilization of generating resources to supply such loads and the fact that most peaking resources are less efficient than base load resources. In the past, hydroelectric power has been available to meet fluctuating power requirements of our customers, allowing us to purchase our supplemental power resources at a higher load factor and at a correspondingly lower average cost. It should also be understood that when a small distribution utility does purchase peaking power wholesale from larger generating companies with surplus capacity to market, it invariably is power provided by those units the generating company considers most expensive in their own resource mix. The lower cost, more efficient units are first relegated to supplying its retail load and its total-requirements wholesale customers. It is seldom possible to purchase "average cost" peaking power from anyone.

Salt River Project (SRP), an agricultural improvement district which utilizes federal hydropower resources, has a contractual exchange agreement with Western. Pursuant to this agreement, SRP's customers receive electricity generated at Glen Canyon, and Western customers receive SRP's generation from its thermal plants in Colorado and New Mexico. SRP and its customers rely on the certainty of this arrangement in making long-term generation decisions, and in aggressively developing and promoting demand-side management programs. Long term resource stability can only be achieved if the life of the resource extends beyond the planning horizon. SRP's demand-side programs, both existing and planned, are dependent on the reliability and stability of its supply-side resources.

Concern over the amount of Western's resources to be allocated in new contracts is also critical to small electric utilities. Most utilities have a seasonal peak, either in summer (as in the case in the Southwest) or in the winter as is characterized by the Rocky Mountain states and the Northwest. Areas such as the Midwest may have distinct peak loads in both summer and winter, often leap-frogging each other. The significance of this is that most utilities need to have some source of generation to supply these peaks as inexpensively as possible. Hydroelectric power generated from water storage reservoirs has always been the best way to serve such loads. However, recent reductions in capacity availability at Glen Canyon dam, coupled with the possibility that generating capacity may be similarly curtailed at other federal hydroelectric projects, will certainly increase the overall cost of meeting these peak loads.

Some advocates of conservation and load management seem to believe that peak loads can largely be eliminated through application of various of these measures. In fact, utilities have been turning to such programs in increasing numbers as a way of reducing costs, even without a federal mandate to do so. It has always been an electric utility's first priority to make sure that when a customer turns on a switch there will be sufficient power available to supply the load. This means that there must be resources available at the time of the system's peak to meet unexpected load increases and unexpected loss of generating or transmission resources. Load management simply cannot shave away the entire peak load, nor can it take the place of real generating resources if they are lost.

The absence of hydroelectric capacity to supply peaking power will invariably cause utilities to construct more combustion turbines which will burn either oil or natural gas, neither of which are renewable resources. Experience has taught us that the price of these resources can be volatile. Most utility planners remember the increases in energy costs resulting from the tremendous increases in oil and gas prices that occurred in the wake of the 1973 oil embargo. Planners also understand that in the event of shortages, natural gas deliveries to fuel power plants will be curtailed in order to ensure adequate supplies to residential and commercial users. Hydroelectric power from Western's storage projects is not subject to such vagaries. While precipitation changes do result in reservoir storage levels that may change dramatically from year to year, the energy from hydroelectric storage projects is still able to be used to meet peak loads. It is usually energy that would otherwise by generated during off-peak periods that is lost due to low flows.

An important characteristic of hydroelectric power plants associated with large reservoirs is that they can respond quickly to fluctuating power needs and that the water releases can by optimized to match the shape of the utility's peaking requirements. This can be done while maintaining adequate stream flow for wildlife habitats. Western, in its EPAM program, has allowed for uncertainty in the future operations of reservoirs by reserving the right to make changes in its sales contracts to accommodate changes in water release requirements stemming from factors relating to wildlife habitat, precipitation changes, and environmental mitigation concerns. This can be done while allocating a high percentage of the original resource. The argument that contract commitments to supply large percentage allocations should not be made at this time does not make sense, because Western is only allocating a percentage of the resource that will be available in the future.

The question of why to do anything this far in advance that would commit the federal government to make long-term commitments and specify percentage allocations instead of waiting until the current contracts get close to expiration needs to be addressed. From the perspective of the contractors of federal power, it has been our assumption that our contracts would be renewed on much the same basis as they were entered into originally. For planning purposes, utilities normally show their hydroelectric resources continuing into the future, barring some project specific problem that would preclude such an assumption. It is only recently that the subject of contract extensions and resource allocations has been an issue and made it necessary for utilities to address the subject now.

The planning horizon for power plants has lengthened over the years. It now takes about ten years from initial planning to project completion to build a 500 MW coal plant. While smaller scale plants can be built more quickly, the permitting and environmental evaluation phases take almost the same length of time as do larger projects. Consequently, utilities like ED2 which contract with Western for the bulk of their power supply must know well ahead of the termination date of their existing contracts whether or not that supply will be there in the future. Given the attacks on hydroelectric power coming from environmentalist groups like those represented in the "LAWF" consortium, it would be foolish for the utility industry to wait until each power contract is due to expire before starting negotiations on the parameters that will be considered in future contracts.

In summary, hydroelectric power is a renewable resource. It is also one of the few that allows for the possibility of storage of the energy by holding water in a reservoir and generating only when it is best to do so. With the exception of wind and solar power, which are both expensive resources at this time and carry their own environmental burdens, hydroelectric power produces no harmful emissions or greenhouse gases. To put this in perspective, consider that Western's hydroelectric generation in 1993 totaled some 21 billion kilowatthours. According to the emissions figures contained in Western's draft EIS, had this power been generated by state-of-the-art coal-fired plants using fluidized-bed combustion, 23 million tons of carbon dioxide would have been released into the atmosphere as well as 15,700 tons of sulfur dioxide (assuming 95% sulfur removal), and 19,240 tons of nitrous oxides.

It is critical to small utilities like ED2 that preference power from Western continue to be made available at a reasonable price and on a consistent long-term basis. Our customers simply cannot afford the potential rate increases that are a very real possibility if the nature of the contract terms is changed through some mandated requirements.

Mr. Chairman, I appreciate both the opportunity to present this testimony and the subcommittee's interest in this important issue.

Mr. MILLER. Thank you very much for your testimony and for your willingness to help us out here this morning.

What is your current status in terms of your existing contract and time of expiration?

Mr. HELLER. The Missouri Basin Members have direct contracts with Western Area Power, Eastern Division, Pick-Sloan, and they expire in the year 2000.

Mr. MILLER. And the current contract is for how long?

Mr. HELLER. The current contract with Western area is through the year 2000. It expires then.

Mr. MILLER. What was the contract duration?

Mr. HELLER. When it was renewed the last time, 15 years, I believe it was.

Mr. BARRETT. Salt Lake City area office contracts were 15-year contracts. They began in 1989, expired in 2004; they have a provision that in 1999 there can be reallocation due to changes, due to environmental considerations in operation of the dams.

Mr. GRAVES. Mr. Heller spoke of the Eastern Division. Western Division, Pick-Sloan contracts expire in the year 2004.

Mr. MILLER. The current contract is 15 years?

Mr. GRAVES. Yes, sir.

Mr. HENDERSON. Our current contracts are 15 years and expire in 2004.

Ms. SCHORI. SMUD's contract is up in 2004. I think it is a 40-year contract that we have had, because we are one of the original guys. We also have a settlement agreement with Western that entitles us to 31 percent of whatever they decide to sell in the future.

Mr. MARTIN. Electrical District No. 2 contracts with Hoover Power through the State of Arizona, and we have a 20-year contract that I believe runs out in 2017. We also have an allocation of CRSP power which expires in 2004; that is a 15-year contract.

Mr. MILLER. How soon do those contracts need to be renegotiated prior to expiration? Five years prior to expiration, three years? They don't do that currently, do they?

As I understand your testimony, you are sitting here saying you don't know what is going to happen to you, you have a got-to-get-on-with-it, because some of you have contracts that expire relatively soon.

Mr. Martin has time to think about it. But there is no set time of renegotiation.

We are not telling you in advance the expiration, what is going to happen. You could end up negotiating this in the fifteenth year under your current situation. Yes or no?

Mr. HELLER. No.

Mr. GRAVES. Western has in the past begun looking at extensions or new contracts significantly in advance of the contract——

Mr. MILLER. Is that custom or contract?

Mr. GRAVES. That is by custom.

Mr. MILLER. You don't have a contractual right to say in the tenth year we want to start talking about our new contract?

Mr. GRAVES. No, sir.

Mr. MILLER. Does anyone have a contractual right about renegotiation in the contract? We are going to try to get you a little bit more animated here, because the reporter can't deal with it. We need some audible sounds.

I don't think you risk a lot.

Mr. HENDERSON. We don't have a contractual right in that sense. As Tom pointed out, it has been the custom of Western to start early on. As was pointed out earlier, there is a provision in our contract—I believe in 1999—that Western has an opportunity to work with us and reallocate to a certain extent the amount of power we would receive.

Mr. MARTIN. Likewise, our CRSP contract has that same provision.

Mr. MILLER. Is that a problem, the fact that the renewal is not a matter of contractual right, as you start to look out into the future. Under the new policy, you will be given 40 years, 25 years, 15 years? Is it a matter of issue when the renegotiation would start?

Mr. BARRETT. Congressman, from the CRSP viewpoint, I believe there is no commitment in the contract that says you will get anything past the year 2004.

Mr. MILLER. I understand that.

Mr. BARRETT. I think a realistic view will be, everybody knows they will get something.

Mr. MILLER. To listen to you guys' testimony, you sound like you expect to get nothing.

Mr. BARRETT. I don't think "nothing" is a realistic expectation. On the other hand, the more certainty you can get to what you are going to have, the better job you can do on an IRP. I think that is the pitch most of us are making here today.

It is not a matter of thinking you are not going to get anything after the year 2004. It is a matter of knowing how much you are going to have.

Mr. MILLER. I understand that. Maybe I am wrong in thinking this, but it would also seem to me that when you look at what the term of the new contract would be, the sooner that the term of that contract could be settled within the boundaries of the old contract really lets you know further in advance. If you knew five years in advance of the expiration of the current contract what the terms of the new contract were going to be, you, in effect, have 30 years on a 25-year contract. You have added five years of certainty to that process, have you not?

Right now you have done this sort of by custom, and maybe that will work. I am just asking you the question.

Mr. BARRETT. I think it would be an added degree of certainty, certainly. Anything is better than where we are today. You are talking to a guy with 20 years. This hearing looks like long-term planning.

Mr. MILLER. Let me ask you, one, on a point that I just raised about what the expectations are, Mr. Graves, you said somewhere in your testimony here that if at the same time Congress "if at the same time Congress expects Western to withdraw a large percentage of customers' existing resource base, which the customers use for existing load, Congress is subverting its own policy."

There is no indication that that is the case, is there?

Mr. GRAVES. Not currently, no.

Mr. MILLER. Right now you are talking about a withdrawal of what? WAPA is talking possibly 2 percent, you keep mentioning 98 percent.

Mr. GRAVES. That is what we would like to see, certainly.

Mr. MILLER. That is in the mix, but there is no indication from Congress that there is any interest in withdrawing large amounts from existing loads.

Mr. GRAVES. That is not clear.

Mr. MILLER. Have you had an indication from Congress that they want to withdraw large existing amounts?

Mr. GRAVES. Not officially, no.

Mr. MILLER. Have you had unofficial?

Mr. GRAVES. Yes. We have heard numbers discussed as high as 30 percent.

Mr. MILLER. Maybe we are in the wrong hearing room. Those are congressional sources?

Mr. GRAVES. I am sorry?

Mr. MILLER. Those are congressional sources?

Mr. GRAVES. Staff contacts, yes, what we have heard.

Mr. MILLER. How did you arrive, if I might ask, as a panel, apparently in all your testimonies, the figure of 2 percent. How do you arrive at that?

Mr. GRAVES. Well, for Pick-Sloan, sir, that is a substantial resource. That is some 40 megawatts. And looking at the universe of potential new customers out there, there simply isn't that kind of load out there even for that. There are only 10 new municipals, no new co-ops. All the co-ops receive allocations of Federal power either directly or through their G&T, as to the municipals, with the exception of those 10.

Additionally, Western is serving State loads and Federal defense loads.

Mr. MILLER. What about the rest of you? How do you arrive at 2 percent?

Mr. BARRETT. For CRSP, sir, if you will read our testimony, we don't support any resource pool. Our comments to Western on the EIS, we support the 25-year contracts and the 98 percent, which will give you a 2 percent resource pool. We arrived at that because that seemed to be the best of the 12 options they had laid out there.

But our testimony does not indicate support for any resource pool because we think the logical thing to do is to put an end-year contract, some provision for adjustment as those needs actually arise and they can be addressed—wait until the need is real.

Mr. MILLER. Anyone else on that?

Ms. SCHORI. If I could go ahead and comment, because I think we sort of proposed to flip it. We are not suggesting there be a resource pool from SMUD's perspective where everyone is automatically forced to give up some share of their allocation. Our preference is to beef up the IRP side and have some commitments that are made that are commitments that are making your resource allocation contingent on the fact that you will deliver energy efficiency in your system, you will deliver renewables in your system, so that we can further those goals.

But as I testified, I guess from our perspective, we need the certainty of the Federal resource being there, because we can average it in then with the cost of some of these other things that we want to pursue and bring down the overall cost for our customers.

So we are not supporting it on the front end. It is really more the reverse of that.

Mr. MILLER. Let's just stick with that for a minute, if I might. Walk me through that, and then I will yield to my colleagues. I have some other questions, but I will take them on a second round.

Walk me through that process on how that commitment—of resources pushes you in the direction of renewable energy resources.

Ms. SCHORI. The time to seize the opportunity when you are dealing with Western's customers, from our perspective, is when they are looking to add new resources or when they have contracts that may be coming up, expiring, or other purchases they are making.

It is very difficult for a customer sitting in a surplus situation to have to commit to—you heard my prices on things like solar-thermal and that sort of thing. What you want to do is leverage those folks, including SMUD, to come in with proposals on how they intend to meet new load, how they intend to address contract terminations that may be coming up, let the customer come up with a proposal.

I am not sure it is going to work for Western to attempt to sit up there with a grand plan, one-size-fits-all for every utility. I think we are all in kind of a different boat.

But let us develop proposals to make us part of our commitment which would then be folded in as part of our overall contracts.

We would like to see Western, on the flip side, unbundle its costs so that potentially we could buy maybe different services than are on the table right now. And I think Western has been very open to talking about some of those ideas.

So I don't have any concrete numbers to throw out today or anything, but that is the direction we would like to see.

Mr. MILLER. The success of that process is really in the details of the contract; is it not?

Ms. SCHORI. Yes, although there is one other issue, and that is, there may be some new customers that are not currently being served who have demonstrated public need; and from our perspective, we would like to work with the CVP Sacramento office to see what needs to be done to deal with those folks.

But it is going to work better, the more you can decentralize—get it down to the area office and then let the area office customers see if they can come up with some solutions that work for those customers.

Mr. MILLER. I don't think we have a disagreement there. My concern is that, you know, sitting on the water side of this issue, which is related in many instances, as some of you know, directly to your fortunes in power, we have watched a couple of systems just get stood right on their heads in terms of potential changes in river management, resource management, from that point of view.

And obviously one of the concerns we have is that once the ink is dry on the contract—now, Cliff has suggested a different arrangement, that the contract have a flexibility so that you can reach in there and adapt to these uses as they come on line—should that be a change in public policy?

But my concern is that when you sit on this side of the dais, is that people sitting where you are start treating this as a birthright, and then the burden on me or this committee or the Congress, which we just went through on the CVP fight, is to wrestle that away from you when, in fact, all it really was was a privilege given by the Federal Government for the use of Federal dollars to develop that resource, whether it was power, water, what have you.

And what concerns me is recognizing what each of you has said in your statement, what you say your goals are and what you want to achieve, is that somehow in the terms of that contract that kind of flexibility is there, because if the presumption is against a change in public policy determined by the Congress, by majority vote and all the things that we have within our system, and then that just leads to a prolonged 20-year litigation fight, we are nowhere, from my point of view.

When I look at my State or you look at the Southwest, you look at what is going on in Nevada, you look at some of the issues around Pick-Sloan that still haven't been dealt with in terms of environmental issues, there are potentially some substantial calls.

It may not exceed the 2 percent, system-wide. It may not exceed that. But if you can't get at it or you have got to fight fox hole to fox hole to fox hole to get at it, then we have got a problem.

Ms. SCHORI. It seems to me, though, that you have got to balance what is going on here. That is what is tough about it.

Mr. MILLER. I am saying from this side, given what you say you want to do and what you believe the needs are and how you have to meld that price of power, given your alternatives in California, that is your side of the argument. Coming at it from the public policy side, with respect to some other concerns that may not sit on your board of directors, but are out there in terms of public policy, that is in the details of those contracts.

So the extent to which utilities are prepared or the customers are prepared to be flexible starts to make you reflect on the term of the contract. The extent to which rigidity is built in, then you have to go to a shorter term because you have to get back at a time when there is sort of an open season for changed public policy concerns. I mean, that is the rub in this mix.

Let me yield to my colleague, Mr. DeFazio.

Mr. DEFAZIO. I thank you, Mr. Chairman. I would like to get a little better idea of the situation of each of the groups or utilities you represent in terms of what—if we are looking for contracts of a long duration, signed in the near future, you must have a pretty good handle on your growth or need projections—you know, your other resources, what is going to expire, what isn't, what kind of uncertainty.

For instance, in my region, the Northwest region, we are looking for proposals of 10,000 or more megawatts of new construction in the next 10 years. And I am just a little curious what is going on in each of your areas. I need that as a little background for some IRP questions I have, so I am just wondering what assumptions you have.

Let's assume you got your existing WAPA allocation. What are the assumptions of additional needs for each of you, if you can go through that real quickly?

Mr. HELLER. Well, I can start, Congressman, if you like.

The growth in our area, the Missouri Basin area, is approximately 2 percent. If we were to receive our full allocations, we are looking at having sufficient baseload capacity, being involved as participants in the river station, our requirements are met through the year 2000. We are looking at gas turbine peaking capacity right now, and the issue becomes how much do we look at, how much increased capacity do we need to fulfill our members' peaking requirements.

That is why this deliberation and the outcome of the WAPA contract is very, very important to us.

Mr. DEFAZIO. And on demand side, what are you using as an avoided cost? Have you done your IRP plans?

Mr. HELLER. We are in the process right now of completing our IRP. Our avoided cost is not very great on a short-term basis. On a short-term basis, it is very, very low, because the LACA river station is the least-cost operating steam thermal power plant in the United States. The cost is very low on a short-term basis.

Mr. DEFAZIO. What is it, then? I am just curious. You said very low.

Mr. HELLER. Well, the cost to produce energy at LACA river station only is less than one cent per kilowatt hour. That is short term.

Our demand-side program that we are looking at, we are looking at integrating all 52 of our long-term contract holders into a coordinated demand-side program. And that process, because of the geographical dispersion we have with the city, is 650 miles by 450 million over a four-State area. It is a process we believe will take four to five years; and we are in the process of coordinating and putting that together right now.

Mr. BARRETT. I am not very well prepared to answer your kind of question, sir. CREDA is an association of 141 utilities. I don't do planning for any of them. But I think, in general terms, at one extreme we would have people like Salt River Project in Phoenix; they are looking at a low growth of 3 percent per year over the next 20 or so years. That is based on a base of 3,500 megawatts. That is a pretty substantial load growth each year.

I know within our membership we have some very, very small Utah communities, very rural, who are actually planning on going downhill as far as load goes. And we have Colorado Springs, which has about the same as the Salt River Project. We have some cities in northern Utah, Provo, who have low growth—substantially like Salt River's, I guess.

But I can't answer your question in detail, I am sorry.

Mr. DEFAZIO. How about the IRP part of the question in terms after voided cost? Have there been a substantial number of IRPs completed? Do you have any handle on avoided costs?

Mr. BARRETT. There are a few IRPs completed. The big outfits that have done IRPs, the Salt River Project is a very comprehensive one. Tri-State, G&T has done it. I don't know what the avoided costs. I can arrange that for the record, if you like.

Mr. GRAVES. Mid-West sits in a similar situation to CREDA, representing over 300 systems in nine States. The growth varies from high-load growth along the front range of Colorado to declining loads in parts of North or South Dakota or Montana. So it is all over the map. As a region, we sit in surplus.

Mr. DEFAZIO. And do you expect if you were to get the WAPA allocation for a contract term such as is being discussed here, that that would continue?

Mr. GRAVES. The surplus has been marketed at the moment, it is my understanding, through the year 2000. If we got our WAPA extension with this resource pool, it would undoubtedly stimulate through the IRP process some aditional demand-side management program. Two percent would be a modest withdrawal and would permit, with sufficient lead time, the opportunity to do the kind of planning necessary to put in good DSM programs.

Mr. DEFAZIO. If you are in a surplus, what kind of assumptions are used? Not too many people are familiar with surplus situations.

Mr. GRAVES. I would defer to Mr. Heller, because he is in the business, but it comes down to probably avoided costs on the LACA river station, which is around $10 million.

Mr. DEFAZIO. Thanks.

Mr. Henderson.

Mr. HENDERSON. My utility is growing or has grown somewhere around 1.5 percent per year. It is depending to a great extent on what happens in the agriculture community, because that is the base. And last year we experienced our best year in terms of low growth; it was a little bit over 3 percent.

Our next kilowatt hour, at present, is costing us about 3 cents per kilowatt hour. In terms of what happens to the WAPA resource, it is critical in terms of what will happen to my utility, because our supplemental power supplier is Tri-State G&T. They have been through the IRP process. In the first draft of it they decided that they had sufficient resources for the next 20 years.

As the situation developed at Glen Canyon, I believe—and I am not completely familiar with another utility—but I believe that their reaction was to go out and purchase additional resources, thermal resources from the San Juan plant in New Mexico. So they were forced to change the direction they were going.

Mr. DEFAZIO. Is that a hard purchase or contingent purchase?

Mr. HENDERSON. It is my understanding it was a hard purchase. But again, I am not that familiar with what is happening in Tri-State. But they are our supplemental power supplier. If they continue to receive their WAPA allocation, we continue to receive ours.

And as Tom pointed out, if we can get at least 98 percent of that resource extended, I don't think we will be seeing new construction for us as a utility. That is our consolidated power authority.

In the State, if I can speak to the State, most of the utilities have gone through the IRP process—Public Service Company is the largest utility. Their plan is to repower a nuclear plant; it will be refired using natural gas. That will provide them with the capacity that they need.

Ms. SCHORI. We have about a 2,100 megawatt loan. We are buying about 360 megawatts from Western right now. Sacramento has been kind of flat as a pancake; we are at about 1 percent growth rate, 1.5 percent, something like that.

Up until this latest marginal cost study, which just finished this week, we were at 4 cents as our avoidable cost, right in that ball park; now we are down to about 3.5 cents, primarily due to the decline in natural gas prices.

We are planning. We have got a commitment to a 600-megawatt demand-side management energy efficiency power plant, as we call it. We are about halfway there, so we have still got about another 300 megawatts to go on the DSM side. And we are planning to do an RFP for renewable projects in 1996, and we are estimating right now about 350 megawatts of renewable commitment.

Mr. MARTIN. Electrical District No. 2 is kind of a unique situation here. Our load is probably about the same as it was in 1980. However, in 1988 and 1989, we had 56 megawatts, which is 20 megawatts higher than our 30-megawatt load this last year.

What happens with us is, we are very dependent on the price and availability of surface water for agricultural pumping. When there is not surface water, they pump. If it is too expensive, they pump; if it is cheaper, they don't pump. If it is available, they don't pump.

My crystal ball has been thrown out long ago in terms of trying to predict what is going to happen with that major segment of our load. So it is kind of difficult.

Right now, if we hit our peak that we had in 1989, again, we would be resource deficient. Presently, though, we are in the surplus mode. How long that will last is kind of a guess on what the weather is going to do.

Mr. DEFAZIO. How do you put together an IRP, then?

Mr. MARTIN. Well, we look at an IRP in terms of basically assuming a flat to very little load growth and that the water management is going to basically dictate taking of surface water deliveries, where possible. Currently, our avoided cost on energy—because we do have sufficient capacity right now to accommodate additional load growth from that perspective—is about 20 mils just on the energy; I daresay more if we had to go out for capacity because it would be higher than that.

Mr. DEFAZIO. Okay. That was helpful. There are a couple of points I want to try and get at. I know I have used a lot of time. Since I took so long for that, I could let you go to Mr. Allard.

Mr. ALLARD. That is okay, he can go ahead.

Mr. DEFAZIO. As I recall the way we set up the IRPs—probably the deadline for having IRPs, since it was three years after enactment—was a year from this October, is that correct, as far as when WAPA notifies people? Does anybody know?

The Act was three years after?

Mr. HENDERSON. That is correct.

Mr. DEFAZIO. And then we said that the IRPs basically should cover a period of five years—well, it doesn't limit them to five years. But every five years after the initial submission, they are supposed to be revised.

I guess what disturbs me a bit here is to say that it is—the IRPs, which I was very involved in negotiating with a number of the

Members here, is the trigger that requires the longer term contracts.

I don't know that we have got that kind of chicken/egg situation here. I mean, we have an IRP requirement that is five years. All the contracts expire within that five-year window. None of them expire within that five-year window, I mean. So, you know, I don't know that we can blame the IRPs for wanting a longer extension.

I can't blame you for wanting a very long extension. If I was in the business, I would look for the longest possible extension for the price that I could get. You have expressed your side and the chairman expressed the other. But I guess I don't want to try to put the burden on the IRP provision of this legislation, because when I look at what is being used for avoided cost, the demand-side management programs are going to be pretty anemic at 10 mils.

The most robust one I heard of sounded like it was around 30 mils. So we are requiring conservation presumably in these IRPs, some as little as nine-tenths of a cent or one cent per kilowatt hour.

I mean, that is not going to get you a whole lot of demand-side management. I guess what I am worried about here is that we may undermine the whole direction of the IRP program if we crank in these very long-term contracts at these very low prices, which are basically required under law.

So, I mean, it is becoming this kind of circular, if you can see it. You are saying you need a long-term contract because of the IRP provision. I am saying the IRP provision is essentially somewhat undermined by the long-term contract; not to say they are exclusive of one another, but I guess you wouldn't have drawn the IRPs into this debate and had just said, we want long-term contracts because we like predictability, stability, and we want to keep the cheapest, largest possible resource base in our list. I can't argue with that.

But I can argue that it is the IRPs that are the problem. If anyone wants to respond to that, if you understood what I said.

Mr. GRAVES. I think the requirement is for an IRP to be filed every five years. The IRP must look beyond the five-year timeframe.

Mr. DEFAZIO. Right. The assumption is, there is enough uncertainty that they don't have a shelf life more than five years in their totality.

Mr. HELLER. I think that is true. In fact, IRPs should be probably reviewed every year. In fact, revisions every two to three years.

Mr. DEFAZIO. The way power markets are going, you would have to do it every minute.

Mr. HELLER. I was remiss in answering an earlier question of yours. Gas turbine, combined cycle unit in our area, currently with gas prices cannot—some of the other questions were around three cents per kilowatt per hour. That is the number we are looking at. I apologize for that. The short-term cost is the 10 mils.

It is very true in our situation, though, as we look at our members' needs, as we plan for future resources, our members have done a substantial number of things in the conservation area. And we are looking at doing several more.

In fact, the four States we represent, one of them has externalities that are involved. So we are trying to incorporate those into this process as well.

There are several that look like they will be very, very cost effective, demand-side programs, if we implement them, compared to the long-term avoided costs. If we are unsure of those resources, though, I cannot afford to have my staff spend time on the demand-side issues when we are not assured or we do not know if our existing resources will be there.

We need to spend time locking in those existing resources or making sure that those existing resources are there. That is the number one concern that I have. I have a contractual obligation to meet.

Mr. DEFAZIO. I understand. You have got an obligation on your side. This is absolutely the converse of what is going on in the Northwest.

In the Northwest, we have—and I grant you there is a different charge PBA has to provide, you know, for the customers—whereas in this case, WAPA has what it has and it has it divided up among the customers. You know, that is a major difference.

But beyond that, PBA wants to sign people up because it is afraid it is going to lose them to IPAs and others who are going to be more cost-effective. Here this seems to be a tremendous concern that if you don't get the long-term WAPA contracts, you are going to have to put all this resource into finding other stable contracts, because it will be so hard to find the capacity out there at a reasonable price.

That is the opposite of what we are hearing up in the Northwest. Granted we are dealing with a much lower base at this point.

I don't know what WAPA is talking about renewing at. I mean, are there still going to be these very, very low prices, or are they looking at any substantial increases? I don't know the state of their transmission system, what kind of capital investments they have to make and what they are assuming in these long-term contracts.

Ms. SCHORI. Can I respond to that? WAPA Power right now, under the CPP project, is at 3.1 cents. Gas is at 3.5. I was going to say, at least in Sacramento and for our area, DSM is very competitive with those numbers; and WAPA Power is beginning to push the costs of other alternatives. So from our perspective, it is very cost-effective; it is a good resource, we want to hold on to it. But there is still a price issue, particularly with DSM. Some of the basic stuff—commercial lighting and those kinds of programs—come in at 1 cent, at least in our system, 1.5 cents, something like that. So there are some very cost-effective programs.

There are other DSM programs we are looking at right now, primarily on the residential side, where we have got to get a handle on how you get that program out and eliminate some of the overhead costs on it to make it more cost-effective.

It is obvious because you have to deal with a lot more small locations to go find the savings. But we have made a lot of progress in reducing the costs of our program. So I wouldn't give up and assume that DSM is automatically going to be higher than the avoided costs of the utilities.

Mr. DEFAZIO. Right. I think you are at the highest end of WAPA's customers. It is harder to deal with than my region because the perspectives are so different.

Mr. GRAVES. The rates have gone up 100 percent in the last 10 years, which is significantly ahead of the rate of inflation. In fact, in the Eastern Division, the peaking rate for Federal power exceeds the rate for non-Federal power.

Mr. DEFAZIO. What is that price?

Mr. GRAVES. Western is about $3 and MAP is $2.75.

Mr. DEFAZIO. I have been showing a figure of $13.31 million.

Mr. GRAVES. That is not the peak. That is the rate composite, which is not the rate that anybody pays in the region.

Mr. DEFAZIO. What is your next kilowatt hour cost then? What is your highest cost per kilowatt hour that goes into the composite?

Mr. GRAVES. For Western?

Mr. DEFAZIO. Yes.

Mr. GRAVES. Purchase power.

Mr. DEFAZIO. At—?

Mr. GRAVES. That has been all over the map. Last summer it became extremely expensive because of the flooding in the basin. Western has spent several millions of dollars, and as they put pressure on the surplus market, the rate goes up.

Mr. DEFAZIO. So then are we doing the IRPs based on the highest-cost, next-kilowatt-hour acquisitions? We are using the composite.

Mr. HELLER. In our case the WAPA purchases that our members make very much indeed keep the cost of their power down to the consumers; there is no debate about that. When we look at integrated resource planning, we look at the marginal savings of the demand side and the marginal, long-run resource costs.

We have to make up the power if it is lost by our members. The costs that we have are the ones that we look at in the Integrated Resource Plan, not the costs that the Western Area Power Administration has. It is the costs that we have.

Mr. GRAVES. Because there is no more WAPA power to purchase. It has been marketed, and the supplemental.

Mr. DEFAZIO. Right, but I am just wondering how we are establishing things. Are we using some of the assumptions we are looking at here; maybe I made a mistake by starting out on the assumption that you have the entire WAPA as you get it today, because I don't know how that compares to this 98 percent proposal you're putting forward. Maybe I triggered several logical inconsistencies in my line of questioning here, trying to get at whether or not we are driving or holding down demand-side acquisition because of this contract proposal.

Mr. MARTIN. Congressman DeFazio, we have an interesting situation, because we have gone ahead, and although we have a capacity to surplus, we have installed low-capacity pumps; we have found a cheap policy to do that.

Another factor we have to consider is 50 or 60 power is nonfirm. And we have seen it go down to one megawatt at times. So although the power may be cheap, there is no guarantee it is going to be there, at least for us. So we have to move on some of these demand-side management.

Mr. DEFAZIO. What I want to get at here is how well we are implementing the IRPs and how we are dealing with demand-side management, and how that relates to the longer term contract extensions.

Mr. HENDERSON. Could I make a couple of comments to that, Congressman?

When we do an IRP, we are really looking at a minimum of a 20-year period. If we want to bring on a new resource, by the time we go through the planning and go through the licensing, the studies that are necessary, so forth, someone said that would take a minimum of five years, sometimes up to fifteen years.

So you see, when we do planning as electric utilities, it is long-term planning. It has been our experience that from the time that we conceive that we need some new resource to the time it is brought into production—it actually is commercial production—would take approximately 10 years.

Mr. DEFAZIO. Right.

Mr. HENDERSON. And try to understand what——

Mr. DEFAZIO. That is a generating resource, not a demand-side management resource. I assume that you have a much shorter time line for your demand-side management resources in terms of assumptions of how quickly they can be implemented. At least in my region, we are able to implement them much more quickly than that.

Mr. GRAVES. The experience we have had in demand-side management, the installation, the measurement to make sure you are getting the savings, it took them over five years. Admittedly, it was a very aggressive program. They have got something like 30 percent of the population of the State in various types of load control. They are controlling 25 percent of their load. But those things take time, and the calibration of that after it is in place, to make sure that it is reliable and can be counted on year after year to generate those kinds of savings, takes time.

Mr. DEFAZIO. Mr. Chairman, I have got someone waiting, so I have to step out. I will be back.

Mr. ALLARD. Thank you, Mr. Chairman. Congressman Hansen had to step out for another very important committee hearing, and I would like to submit his statement for the record.

[Prepared statement of Mr. Hansen follows:]

Testimony of
Congressman James V. Hansen
Subcommittee on Oversight and Investigations
June 16, 1994

Mr. Chairman, I would first like to welcome all of the witnesses including Mr. William White, Dan Beard and from my state Cliff Barrett.

Power generated at federal hydropower dams is very important to the West. Western Area Power Administration (WAPA) provides power to many of my constituents and is important to the continued vitality of the West. The question of who will get the WAPA power and for how long is an age old question that I hope will finally be solved.

WAPA is to be commended for continuing the development of the Energy Planning and Management Program (EPAMP) draft Environmental Impact Statement (EIS). I agree with the findings of the EIS in that Integrated Resource Planning (IRP) when coupled with maintaining longer contracts leads to environmental benefits.

Maintaining longer contracts leads to more WAPA customer stability, and that stability leads to environmental benefits. Significant reductions in environmental impacts can be achieved if long-term (25-35 year) contract extensions are granted. If WAPA customers are not allowed the flexibility granted to them by long-term contract extensions then WAPA will continue to have to replace clean hydro power with air polluting coal power. The Draft EIS shows the environmental benefits increase as the contract term increases from 25 to 35 years.

The longer term utility planning focus associated with maintaining long term WAPA allocations, coupled with the decreased pressure on the utility revenues to fund hedging programs, allows the utility to focus on meeting customer end use needs with increased demand side management and decreased supply side additions.

The Secretary of Interior has shown that he presently has the flexibility to alter the operation of federal dams under the current WAPA contracts. It is my desire that we do not hand cuff WAPA customers for the sake of providing the Secretary greater flexibility that he has already shown he has.

Mr. ALLARD. Mr. Hansen asked me to ask some questions on his behalf and to direct these to Cliff Barrett. There are about three questions here. And so I will ask the first question.

The Ute Mountain Indian tribe has indicated interest in receiving an allocation of power from the Colorado River Storage Project. Does CREDA have a position on the Ute request?

Mr. BARRETT. Yes, sir. I think this question gets to the issue of, do long-term contracts prevent the government from meeting new demands and satisfying new needs?

Mr. ALLARD. That is my next question.

Mr. BARRETT. I think you will hear later today that the Mountain Utes are looking for in the order of a five-megawatt allocation from Western or CRSP Power. And CREDA would support that on the basis that Ute Mountain Ute Tribe is a preference customer. We think there is an easy fix to that problem. The Bureau of Reclamation has reserved about 175 megawatts of project power for project purposes.

Now, that power is not available to Western, is not marketed by Western on long-term firm contracts. So it is not available to us as customers. It would be a very easy matter for the Bureau to take part of that 175; so far they have only identified real uses for 60 of the 175. This leaves quite a bit laying on the table.

The Ute Mountain Ute Tribe is a participant in the project. It seems to me you could allocate five megawatts to the Ute Mountain Utes, satisfy their need, and do all that within the context of the existing contracts. And we would support doing that.

And that could be done very, very quickly. All it takes is the Bureau of Reclamation to decide to do that.

Mr. ALLARD. Thank you.

The second question is, have the existing CRSP Power contracts prevented the Bureau of Reclamation from making changes in the operation of multipurpose facilities in CRSP?

Mr. BARRETT. Well, I indicated in my testimony, it certainly hasn't slowed them down a bit on Glen Canyon Dam. We lost a third of the general rating capacity of Glen Canyon Dam, all of the existing contract, the power customers. We have worked on trying to get good science so the changes made were scientifically based, and we have supported those changes through the EIS process.

Another outstanding example is Flaming Gorge Dam where, as a result of some requests by Fish and Wildlife Service to have release patterns changed for the endangered fish, we lost about a third of the capacity in the winter, all of this done within existing contracts and without any fight on our part except to make sure that they were scientifically based.

Mr. MILLER. If the gentleman will yield, maybe distance makes the memory less painful. Let's not say that there was no fight or that this was all agreed to up front, because that wasn't the case. Politics became clear; the agreement became available.

When the Utes first went to WAPA, they were told they needed a change in statute. It wasn't all lovey-dovey, no problem. They were told, first, they couldn't have it, they didn't qualify—not by you, but I am saying by WAPA. So the notion that they were easily assimilated into this pool of power, I appreciate the generosity of all of you, but you are not that generous, okay? It was a little more difficult.

I just walked through California, trying to get a little opening up of this process, and it doesn't quite work that way either. So let's not pretend like there aren't real issues, and if we just continue on with the status quo, it can all be accommodated, because the issues are getting tougher and tougher in a confined pool of available resources.

Mr. BARRETT. I would agree with that, sir, but I would point out, the question was, does CREDA support that, and we do.

Mr. MILLER. I appreciate all your support.

Mr. BARRETT. We think there is an easy solution to that problem. The Federal agencies wouldn't do it.

Mr. ALLARD. Reclaiming my time.

Mr. MILLER. You have got it.

Mr. ALLARD. Okay. So now, I am trying to remember, is your distribution system, is that an energy surplus or an energy shortage testimony?

Mr. BARRETT. Generally, our part of the United States is in energy surplus right now.

Mr. ALLARD. So you have plenty of surplus. So it wasn't a problem for you in giving up on some of these issues?

Mr. BARRETT. Well, the only problem we had was not a—it is much more expensive than the generation. We are paying the price. That is the problem.

Mr. ALLARD. The third question that Congressman Hansen had for you is, you have given us some information about demand-side management programs implemented by the Salt River Project in Arizona. Can you tell us anything about what CREDA members in Utah and the other upper basin States are doing on conservation and demand-side management?

Mr. BARRETT. Well, certainly the Salt River project is a sterling example, and they are in a unique position to do that because of their size and the size of the resources.

There are other good examples. For example, in Colorado, the Platte River Power Authority, which is made up of Loveland, Longmont, and Estes Park, they have done a pretty good job. They have done rate incentives, they have saved off their winter peak 17 megawatts.

In Utah, the real small communities have a very difficult time with this because they don't have the resources. They have all tried to do something, but the results are not really outstanding. One of the best ones is the Utah Municipal Power Agency, which is six cities; they have done quite a bit of work in renewable resources. They have put in a number of small hydro plants. They have invested significant money in geothermal resources.

The point is that everybody is trying to do something out there. It is not like nobody's doing anything.

Mr. ALLARD. I appreciate your response.

Mr. Henderson, I had a couple of questions here that I wanted to direct to you. When you are analyzing the power needs of customers, is it always possible to predict with certainty how they will react to your conservation programs that you put in place?

Mr. HENDERSON. No, sir. I will go back to some of my previous experience in the job I had when I worked with Georgia Power. We wanted to control the air conditioning load. And we gave a very strong signal to the customer in terms of the demand charge; and when we would have a hot day like we had yesterday, if it was one day, they responded well to our situation; the load did not set a new peak.

But if this goes on for three or four days, the customer's attitude changes, and all of a sudden he puts on as much air conditioning as it takes to make him comfortable, and he tends to leave that on, and we set new system peaks, even though we sent a very strong economic signal to the customers.

And so what I have tried to explain is that we can do education, we can do incentives, we can send signals to our customers, but the way they respond may vary over time, and depending on the circumstances—that is less predictable than having a resource out there—a generator that I can depend upon to put out its name plate rating.

So when we have an Integrated Resource Plan, we are trying to balance supply-side options, of which the purchase of WAPA power is one of those supply-side options, with demand-side options. And at least in my mind, the supply-side options bear a great deal more certainty as to what they will provide for me than the demand-side, as I gave you an example of how that sometimes varies the results.

I think, as I tried to point out earlier, this is over a period of years. Not five years, not ten years, but typically twenty years or more. And it deals with both the supply-side issues and the demand-side issues.

Now, if I am dealing with load growth, I am very comfortable—over a 10-year period—if my loads are growing 1.5 percent; we are looking at something like 15 percent of my load at the end of the 10-year period. But if you are talking about something happening to my WAPA contract that meets 38 percent of my load requirements on the supply side, if there is uncertainty associated with that, I have a much greater problem than I had dealing with the load growth, which is the main issue we have when we prepare an IRP.

I hope that is clear.

Mr. ALLARD. There are certain market factors that go in on demand. If your demand goes up, the price of electricity goes up; then the people respond by consuming less electricity.

Mr. HENDERSON. That is generally true, but I gave you an example where that didn't work so well.

Mr. ALLARD. Yes, I appreciate that.

If you could no longer count on WAPA for safe, clean hydroelectric power to meet your customer needs, is it likely you would be compelled to replace that power with some sort of thermal resource that might have a greater adverse impact on the environment?

Mr. HENDERSON. That is correct.

Mr. MILLER. That is a surprise. Film at 11.

Mr. HENDERSON. A number of the members of our association have completed the IRPs, and they have not found renewable resources, for example, that can compete with the traditional thermal resources. If we lose that big part of our power supply, then we are going to have to go out and do something; and the response is, we will do what is most cost effective.

And what we are trying to say to you here today is simply this. If you want us to be aggressive with demand-side management, we need to be sure that the supply-side resources will be there, including the WAPA resource. Then we are dealing with a much smaller section—our load growth, things like that that we can handle with demand-side management.

But regardless of what we do with demand-side management, we still must have something that produces a product. Because what we are doing is managing the use of the product with demand-side management, and we still have to have that base; that base is going to be thermal resources and the WAPA resource.

Mr. ALLARD. In talking with a lot of the energy providers, the district that I represent in Colorado, they continually raise concerns about peaking power, and how you have to reach these peaking demands. Sometimes you can talk about an adequate supply of energy during demand periods, but when you get into peaking periods, it is a different situation and very difficult sometimes to make the adjustments to meet those peaking demands.

Are you having problems meeting the peaking demand?

Mr. HENDERSON. As a utility, the Arkansas River Power Authority is not. This is the reason why. We have a great deal of capacity, much more than our load at the moment.

Mr. ALLARD. So you are able to——

Mr. HENDERSON. We are able——

Mr. ALLARD. To these or areas——

Mr. HENDERSON. We are able to bring on that generation in emergency, in peaking periods, if necessary. The problem is that it is very expensive to do so. And the problem is that we are a relatively small utility; a utility—as large as Tri-State or Public Service Company—facing the same problem has a much greater problem to deal with than we do.

Our situation is unique. If we did not have that surplus capacity, we would face the same problems that the larger utilities do. It is a unique situation.

Mr. ALLARD. Do you have an opportunity to sell some of that energy to the larger utilities to meet their peaking demands?

Mr. HENDERSON. In the past we have. But we really can't make a dent in their needs. What happens at that level, they are so much larger. We can help ourselves, but to help someone else, we are not large enough.

Mr. ALLARD. You help yourselves because it is a higher-cost energy and you can. It helps you pay your bills because you can sell at a little higher rate?

Mr. HENDERSON. Whatever the cost of our energy, we pass that on. If there is an increase, it is passed on immediately to our customers. If there is a decrease that is passed on. So whatever our expenses would be during that period of time, it would be passed on immediately to our customers.

Mr. ALLARD. But in peaking power, you don't market that again?

Mr. HENDERSON. No. We just recover our costs.

Mr. ALLARD. Because you are just too small, you say, to even have an interest in any of the larger utilities wanting to buy your peaking power?

Mr. HENDERSON. We have discussed with some of the utilities about arrangements. We have come to no firm conclusions where we would take our surplus capacity, package it with some of their energy, and then make a product. But we have come nowhere close to concluding any of those discussions.

Mr. ALLARD. I have one more question here for Ms. Schori?

Ms. SCHORI. Yes.

Mr. ALLARD. In your comments to the DEIS, the Bureau of Reclamation, in their comments, the Bureau of Reclamation said that long-term contracts take away their flexibility to deal with environmental considerations, most notably fish. Your testimony states that power contracts do not constrain the Central Valley Project operation, that power entities realize that they have to be flexible with respect to the reservoir operations.

It looks like you have taken away one of their main arguments for those who want very short contracts.

Ms. SCHORI. The point I made in my testimony earlier is, I recognize that there may have been some experience with water contracts that was difficult, and maybe some power contracts, but in our area, the Sacramento area, I think that the contracts basically don't have provisions that prevent the government from addressing the needs as we go along. Obviously, we end up having meetings and trying to work through the issues and come up with a reasonable way to foot the bill or to operate the projects as need be. So the recommendation we are making is that historically we have been able to come up with new definitions of "available resource" and work that through.

I am sensitive to the comments the chairman made earlier, and sometimes this can be a difficult process, but the contracts themselves have not been a bar to trying to address those kinds of issues.

And we would foresee similar flexibility in the future on the power side.

Mr. ALLARD. Thank you. Mr. Chairman, I am finished. Thank you.

Mr. MILLER. Thank you.

Quickly, because we have a vote here, Mr. Heller, Mr. Graves, what is your position on the allocation of power to the Indian tribes? What is your ability to do that?

Mr. GRAVES. We have no ability to make allocations to the Indian tribes. That is Western's responsibility, as I am sure you know. If the Indian tribes qualify as preference customers, under WAPA's marketing criteria, they are entitled to an allocation.

Mr. MILLER. Do you believe they qualify?

Mr. GRAVES. Currently?

Mr. MILLER. Yes.

Mr. GRAVES. I am not familiar with the situation on all the reservations, but I would doubt it, because they do not have utility responsibility. Most of the reservations are, in fact, served by rural electric cooperatives and do enjoy the benefits of preference power to the same extent that everyone else in the region does.

Mr. MILLER. So they would have to be a utility?

Mr. GRAVES. They would have to be in the business of distributing electricity, yes, sir. That is one of the primary criteria for preference.

Mr. MILLER. Mr. Heller.

Mr. HELLER. We have supported the position that Tom has indicated also; with the qualifying criteria met, we would not oppose those allocations being given.

Mr. MILLER. Do they have to be utilities? Is that your understanding?

Mr. HELLER. That is my understanding, yes. And I think there are several utilities that have met, in the past, those requirements.

Mr. MILLER. Doesn't Western sell to others? Don't they sell to Bay Area Rapid Transit, that is an end user? Or the Folsom Prison? They sell directly to an end user. What disqualifies the tribe?

Mr. GRAVES. I am not entirely familiar with CVP in terms of what marketing criteria there are. Folsom Prison is a State facility.

Mr. MILLER. It is not a utility.

Mr. GRAVES. No. It is a State facility such as a public agency. And Western did inherit a number of arrangements from the Bureau of Reclamation that were made many, many years ago, serving State loads in the upper Great Plains as well.

But as I said, the members of the tribes currently do receive the benefits of Pick-Sloan Power.

Mr. MILLER. We are going to receive testimony later that they want an allocation; are we not?

Mr. GRAVES. I do not know. I assume.

Mr. MILLER. In your region, have there not been requests for——

Mr. GRAVES. They have testified in the past, yes, sir.

Mr. MILLER. Thank you. The committee is going to adjourn, I think we actually have two votes, back to back, so it is going to be about 15 or 20 minutes. If that complicates people's lives, you are excused, so thank you very much for your time and your testimony. This is obviously running longer than anticipated, so if there are others who that causes a scheduling problem with and they want to simply leave their testimony in writing, they are certainly welcome to do so. It will not prejudice your position at all before the committee.

I just understand that this has gone longer than some people had anticipated.

[Recess.]

PANEL CONSISTING OF WILLIAM H. WHITE, DEPUTY SECRETARY, U.S. DEPARTMENT OF ENERGY; AND, DANIEL P. BEARD, COMMISSIONER, BUREAU OF RECLAMATION, DEPARTMENT OF THE INTERIOR

Mr. MILLER. The next panel will be made up of the Honorable William White, Deputy Secretary, U.S. Department of Energy, and the Honorable Daniel P. Beard, the Commissioner of the Bureau of Reclamation.

Welcome to the committee, and before we begin with you, I would like to recognize Congressman Williams.

STATEMENT OF HON. PAT WILLIAMS

Mr. WILLIAMS. Thank you, Mr. Chairman. I appreciate the courtesy of making a brief statement while this panel is assembling at the hearing table. I appreciate your courtesy in allowing me to do this.

As you know, I chair a subcommittee that has jurisdiction over national health care reform and the Chair is a member of that subcommittee and we are involved in meetings now.

Mr. MILLER. That may never end.

Mr. WILLIAMS. I have to take this opportunity to be here and at least speak for one minute about an issue of extraordinary importance to us.

The Chair has been up to Montana several times. I don't know, George, if you have had the opportunity on those trips, some of which I have been with you during, but I don't know if you have had the opportunity to fly over Montana at night, but on a clear night, we have a lot of them out there, if you are flying over Montana, you can see very quickly from the lights the extraordinary problem that we have in linking our towns and ranches to the power grid.

In the WAPA territory, we have one electric co-op person per mile of power line. Federal support through WAPA makes that power affordable. Only Federal support through WAPA can make that power affordable. And if there should be a significant change in our share of the allocation through WAPA, and our co-ops had to look elsewhere, for example, to Basin Electric, the power rates for that one customer per power line mile, their power rates would triple.

We could do it another way. We could build another fossil fuel generating plant out there, and while we were doing that, we would watch virtually all of our hydroelectric power which we helped provide to this Nation and to WAPA continue to go out of State while our rates were tripling and we were building fossil fuel plants.

So my point, Mr. Chairman, is it is extremely important to us as we join you in this cooperative effort to look at the possibility of changes, that the power allocations be done in such a way so that people who are on the fragile end of appropriate, reasonably priced power grids do not fall off of that fragile end.

Mr. Chairman, again, thank you for your courtesy in letting me have a minute here to express that. I wish I could stay and listen to Mr. White and my good friend Dan Beard testify, but health care reform calls and I have got to get back to these meetings.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Williams follows:]

PAT WILLIAMS
MONTANA

MAJORITY DEPUTY WHIP

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Congress of the United States
House of Representatives
Washington, DC 20515-2601

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GENERAL COMMODITIES
NATIONAL PARKS AND PUBLIC LANDS
NATIVE AMERICAN AFFAIRS

STATEMENT
U.S. REP. PAT WILLIAMS
June 16, 1994

Thank you Mr. Chairman for calling this hearing and providing the committee with a very timely opportunity to review the power allocation and contracting process of the Western Area Power Administration (WAPA).

Western was formed in 1977 to market the power generated at federally owned dams, a function previously handled by the Bureau of Reclamation.

The investment we made in a federal power system is a success story in my state, making power available to rural areas at a time when private utilities would not provid the service. Today we have economic activity in these areas which is, through taxes, repaying the investment in these federal projects many times over.

Montana is a net energy exporter, using just a small part of the energy generated in our state. Importantly, though, this energy is the economic mainstay for Indian Tribes, irrigation districts, and the members of rural electric cooperatives.

Mr. Chairman I invite you, the next time you are flying over Montana at night to take notice of the extraordinary problem we have in linking our towns and ranches to the power grid. In the WAPA territory we have just 1.1 electric cooperative members per mile of power line; federal support through Western makes this power affordable.

If Montana's share of the allocations through Western were to drop our cooperatives would have to look to Basin Electric for replacement power at <u>triple</u> the rate. Obviously if demand couldn't be met there we would face building another fossil fuel generator, all the while watching the balance of our hydropower going out of the state.

The federal system has played the vital, leading role in supporting rural infrastructure and economic development. The system is working well for Montana, and so I appreciate the Chairman's working with me and the other members of the Committee to help continue, in an appropriate way, this critical federal service.

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Mr. MILLER. Mr. White, welcome to the committee, and your statement will be included in the record in its entirety and you may proceed in the manner in which you are most comfortable.

STATEMENT OF WILLIAM H. WHITE

Mr. WHITE. Thank you, Mr. Chairman. It is a real pleasure to be here. I know for this statement I personally put in as much time as any other statement that I have prepared since I have held this job. So when I put it into the record, I know there are some good things in it, including some highlights that I won't get to hit, and some answers to your specific questions.

I thought what I might be able to do, though, is visit with you about what I consider some highlights in the statement, and the issues that we struggled with. What I tried to do is take this and your invitation to testify as an opportunity to send some pretty clear signals about some new directions that the Department of Energy and WAPA might take, and also to reaffirm some principles that we think are wise, and that are fundamental to WAPA. So what I would like to do is just spend a few minutes on the issues that we wrestled with the most, to highlight what some of those are within the statement.

I will say this as a preliminary comment. I think we all within the department, and I personally, have a sense that, Western is in a position of reevaluating some of its premises, not the premise that it should provide an important public service out West; not to reevaluate anything in a way that causes immediate anxiety after a hearing, but to recognize that parts of the West are changing pretty fast and that Western needs to be in a position to change so it is really responsive to the region.

So with that sort of general thought, let me share with you, some of the issues that we grappled with and that I think are highlights of the testimony.

First, the role of renewables, besides hydro and efficiency. I visited with Western and many of its customers personally, and I have corresponded with customers and other stakeholders who are interested in WAPA, such as environmental groups. I have come to the conclusion that maybe in the past, WAPA has not looked as favorably on purchases of efficiency and renewable resources, other than hydro, and where other power supply was needed.

We make a commitment today—I talked to the administrator—that, when it comes to the next point at which we solicit power, renewables and efficiency are going to be included in that solicitation and compared on some realistic basis over a period of time, using principles of integrated resource planning.

As you pointed out in your questions, WAPA is not just a hydro energy provider. Because of the nature of hydro energy, there will be times when WAPA provides power from other forms of energy and can provide leadership in demand side planning. WAPA should look at itself more as a total resource provider and emphasize those areas more than it has in the past.

The second major area of discussion that is of interest, originally through leadership in WAPA with some nudging by this committee and the Chairman, and then in statutory language, is that customers are required to go through an integrated resource planning process. This is something that many utilities have done and done very successfully. We now have a track record in your home State for one, and we are preaching to the rest of the world that they ought to be doing I.R.P. So, we ought to do it at home wherever we can.

As your questions pointed out, Western has had to supplement its hydropower resources with other resources, principally to meet contactual commitments so WAPA is in the business from time to time of looking at other resources. Therefore, it should subject itself and those purchases to the same type of integrated resource planning as Western expects of its customers. Western has made the commitment to do that. I think that will also be pretty good for Western, because how can you understand what your customers are going through unless you have gone through a similar process yourself?

The third thing that we want to be clear on, and I will bring a little legal thought into play, is that we understand these customers are under an obligation to do integrated resource planning. Customers may come up with integrated resource plans at the same time contract extensions are needed, but we understand, and the customers should understand, that I.R.P. is a legal requirement and not simply a quid pro quo.

There are two other points that I would like to cover. All of those areas I just covered are major areas of change in this organization. There are two things that the organization has done a pretty good job of, though, that I want to make clear that we don't want to jeopardize.

Western is located near its customers. When we, those of us in Washington and in government, begin in Washington to deal with relationships and processes which have been enduring for a long time, we need to do so in a careful and respectful way. Because we are talking about relationships which have been built over a period of time, it is important that I and others include the customers and others within the decision-making process. This is so that we don't get into a situation in which people are not arguing over objectives; they may not even be arguing over means, but they are arguing over distrust because some bureaucrat from Washington they never heard of starts preaching to them.

So we want to respect some processes that WAPA has as we take it to its new future that we have outlined. We want to keep in close touch with its customers so that they know where we are heading, and it is not just some person who read a book one night, thought he came up with a bright idea, and now is going to impose it on people that he or she never met. I undertake to bring a sense of humility to this job.

Second, there are some issues over which WAPA and other stakeholders have a disagreement, which are really more matters of fact rather than theory. I will give you a very plain one. It is what percent of the power available needs to be reserved in order to allow additional customers to come on line.

I would like to resolve those types of issues based on a straightforward analysis of the facts, as opposed to inertia on one hand or reassertions on the other.

The same thing applies to the issue of just how far in advance do we prudently need to extend contracts in order to avoid having something backfire and the customers start looking for other power sources which might not be as environmentally compatible as well-managed hydropower.

So it is a pleasure to appear before you, and I will be happy to answer any of your questions.

Mr. MILLER. Thank you.

[Prepared statement of Mr. White follows:]

STATEMENT OF

MR. WILLIAM H. WHITE

DEPUTY SECRETARY

U. S. DEPARTMENT OF ENERGY

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

COMMITTEE ON NATURAL RESOURCES

U.S. HOUSE OF REPRESENTATIVES

JUNE 16, 1994

Mr. Chairman, thank you for inviting me to testify before your committee today on the issues surrounding the development of new power marketing policies by the Western Area Power Administration (Western). Although the testimony I offer shall focus on some specific issues, I want to offer to you a new vision for Western by this Administration.

The final form these policies take will help shape the electric utility industry in the western United States. The Department of Energy and Western are working with the Congress, our customers, and the public to develop sound, workable power marketing policies -- policies that promote environmental protection as well as economic growth; that are responsive to changing regional and utility industry needs; that balance energy efficiency with supply needs; and that promote stability of the federal hydroelectric supply within the region.

Western's potential as a force for positive change is found in the breadth of the service it provides. Western markets and transmits federally-produced power throughout a 1.3-million square-mile geographic area in 15 central and western states to 609 customers and customer members. Western operates and maintains 16,658 miles of transmission lines, 271 substations, and other associated power facilities. Electric power marketed by Western is generated at 55 plants operated primarily by the Bureau of Reclamation (Reclamation) and the U.S. Army Corps of

Engineers.

Western proposed the Energy Planning and Management Program (Program) in April 1991. The Program sought to promote long-term energy planning and efficient energy use, and to support those policies through power resource allocations designed to enhance resource certainly and stability. Integrated resource planning (IRP) was the tool of choice for long-range planning; resource stability for Western's customers was considered critical to its success.

In May, 1991, after publishing a notice of intent to prepare an environmental impact statement on the proposed Program, Western held 15 scoping meetings and alternatives workshops throughout its service territory. This effort to solicit the input of the public resulted in preliminary recommendations including a resource extension proposal, integrated resource planning for all of Western's long-term firm customers, and a penalty provision featuring a total loss of a customer's hydropower allocation for noncompliance with the IRP rule.

Prior to completion of the draft EIS, the Energy Policy Act of 1992 (EPAct) was signed into law. Section 114 of EPAct requires integrated resource planning, makes allowances for small customers, and includes a moderate, rate-based penalty for non-compliance with the IRP provisions of the statute.

The Secretary, reflecting the new Administration's desire to promote positive change, to work closely with the Congress on the issues, and to comply with the new EPAct provisions, directed Western to amend the draft EIS in September, 1993. Specifically, Western was directed to refrain from designating a preferred alternative, to expand the options under review, and to solicit further public input and comments on the proposed Program.

The notice of availability of the Program's draft EIS was published in March, 1994. During the following 45 day comment period, Western held eight public hearings in seven states. Over 190 comment letters were received, 170 of which were from power customer groups or individual customers. There was one joint letter on behalf of seven environmental groups, five letters from Native American tribes, and individual letters from state and federal agencies and utility associations.

I say this in way of background. First, it demonstrates how important public input is to Western and the Department -- we take this process and these comments very seriously. Citizens have become intolerant of decisions by governmental entities which do not reflect the preferences of people actually dealing with those entities on a daily basis.

Second, this background underscores how time-consuming it is to develop new power marketing policies.

Third, the input from Western's customers and the public leads us to certain preliminary and valuable conclusions:

1) Experience has shown Western the difficulties associated with long-term forecasting and with entering into long-term contracts with limited flexibility to adjust to changing circumstances. On the other hand, our experience with the current process also shows us that some short-term contracts have been inadequate. A forty-year contract precludes the flexibility needed to adapt to changing conditions; a ten-year contract may force the region to consider new, unnecessary supply alternatives which impose higher economic and environmental costs than would a well-run hydro system.

2) We agree that power should be available for new customers; the issue is simply the size of the needs of those new potential customers. We intend to set aside sufficient power in a resource pool to meet a fair share of the needs of new customers. The appropriate percentages should be based on the most reasonable projections available.

3) Customers rely on Western to purchase firming energy on a least-cost basis. To meet this responsibility in the future, Western will consider all energy alternatives in its purchase mix, including renewables and energy efficiency. Here, today, I

make the commitment for Western to assume leadership in helping to create a bigger renewables and efficiency resource in the west.

Western's customers will benefit by receiving the lowest possible rates; the environment will benefit from Western's purchases of environmentally sensitive sources of energy; and the larger public interest will be served by Western's efforts to foster the use of clean energy.

The Program issues faced by this Administration, the Department of Energy, and Western are significant and timely. Many beneficial public purposes can be served by Western's power marketing programs. Numerous exciting electrical technologies are emerging today or are on the horizon; technologies that will have improved economics and environmental benefits over existing practices.

We are very interested in hearing the views of this Subcommittee as the Department develops its EIS preferred alternative and proposed rule on the Program. We intend to make our proposal after careful consideration of the pros and cons of each alternative.

I would now like to address those questions raised by the Chairman in his letter of invitation to appear at this hearing.

<u>Question 1</u>. "Can the Department of Energy predict with confidence the amount of hydroelectric power that will be available to market from the Loveland and Salt Lake City Projects in 2004, Parker-Davis in 2008, or Boulder Canyon in 2017? According to the Bureau of Reclamation's comments on the DEIS, '. . . insufficient information is available to Western to enable it to make a sound decision relating to contracts that will expire 10 years from now.'

In light of the uncertainty surrounding the future availability of these resources, wouldn't it be prudent to defer these power allocation decisions to a later date?"

<u>Answer 1</u>. I agree with the Chairman's statement that the amount of hydroelectric power available for Western to market in the future is not predictable. Western's past experience in marketing power has shown the pitfalls of committing to a defined amount of capacity and energy in a long-term contract, with limited opportunity to adjust to changing circumstances. Due to the uncertainty surrounding the future availability of power resources, no definitive decisions about the amount of marketable resource are proposed in the EIS.

For those alternatives in the draft EIS that feature an extension of power resources, Western has proposed to extend a percentage of the resource made available in cooperation with the generating agencies at the end of the existing contracts. In this way, Western would be able to take into account changes in operations and hydrology at existing generation facilities before the term of the new resource commitment to customers actually starts. Western also proposes to reserve the right to adjust its marketable resources on a fixed-window basis or on a 5-year notice, to allow for changes due to longer-term operational issues. Only those features that support the resource certainty needed for meaningful IRPs would be dealt with at the time of the contract extension. Exact resource definition and allocations to customers would take place in the future on a project-specific basis, and additional project-specific environmental documentation would likely be required at that time. We want to avoid a situation in which citizens begin to plan supply alternatives at higher environmental and economic costs because they perceive that Western has been trapped by indecision or inertia.

Extensions would be phased in on a project-by-project basis as existing contract terms near their end. I agree that it is too soon to extend resources for the Salt Lake City Area/Integrated Projects, the Parker-Davis Project and the Boulder Canyon Project. Application of any extension of resources should not take place for the Salt Lake City Area/Integrated Projects until the ongoing electric power marketing EIS for that project is

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completed. No proposal to extend resources should be implemented for the Parker-Davis and Boulder Canyon Projects until a later date, no sooner than ten years before the termination of these contracts.

Question 2. "The power allocation options in the WAPA DEIS all reserve between 90 and 100 percent of the available power resources for current WAPA customers. Is the reservation of such a large proportion of these resources for current customers prudent when it is impossible to determine what preference entities will be applying for power resources when contracts expire 10 to 20 years from now?"

Answer 2. I agree that it would be imprudent to reserve in 1994 a fixed percentage of a resource for contracts that will not expire for twenty years. No proposal to extend contracts and reserve resources should be implemented for the Parker-Davis Project or the Boulder Canyon Project until a later date. For contracts expiring in 2004, the new marketing policies will be implemented subject to changes required by project-specific requirements. If during the project-specific public process a larger, or smaller, resource pool is appropriate, adjustments can be made at that time.

Western has a history of making power available for new customers when a new marketing plan has been developed. One hundred and twenty-two new customers have received over 235 MW of power from Western as a result of the currently effective marketing criteria for the Piçk-Sloan Missouri Basin Program-Eastern Division, the Loveland Area Projects, the Salt Lake City Area/Integrated Projects, the Central Valley Project, the Parker-Davis Project, and the Boulder Canyon Project. Western should market its resources in a manner that encourages the widespread distribution of Federal hydropower.

Western does not have enough marketable resource to meet the total electrical requirements of its customers. As with current customers, Western will meet only a portion of the needs of new customers to assure equity between customers in its marketing programs. The rest of each customer's load must be met by its own generation or by a supplemental power supplier.

Western has evaluated the number of potential new customers within its marketing area to assure that the resource pool is appropriately sized. A resource pool of up to 10% will accommodate a fair share of the power needs of new customers. Due to Western's practice of periodically making power available to new customers, there are relatively few preference utilities left within Western's marketing area that do not receive Western hydropower, either directly or through a member-based association. Those existing preference utilities that do not receive Western hydropower have either been recently formed, have not been successful in obtaining transmission access, or are locked into long-term power supply contracts with other parties.

Power from any resource pool would be allocated to new customers under future project-specific public processes that would not be completed until 3 or 4 years before existing contracts expire. The close proximity between the new customer allocation process and the end of existing contracts will help assure that all potential new customers can apply for hydropower; Western should not exclude new customers from participating in the allocation of power 10 to 20 years before existing contracts expire.

Question 3. "The general conclusion of the DEIS's environmental analysis appears to be that the more power WAPA reserves for current customers, and the longer the contract extension, the better the result for the environment because customers will utilize WAPA hydroelectricity instead of building their own fossil fuel-fired generation. However, this conclusion is based upon the inaccurate assumption that WAPA markets only hydroelectricity from federal dams and purchases no power.

Please provide, on WAPA-wide and project-by-project basis, estimates of the percentage of the electricity that WAPA has provided to its firm power customers in each of the last 5 years that is from fossil fuel-fired generation. Shouldn't the DEIS analyze the environmental effects of WAPA's purchase and sale of

WAPA electricity that is produced from fossil fuels?"

Answer 3. First, in response to the general concern raised, I agree that the policy issue of purchased power is important from both a fiscal and environmental perspective. I am pleased to inform the Committee that resources needed to firm up Western's hydroelectric commitments will be considered in accordance with existing laws and IRP principles in the future. Requests for Proposals will be issued to meet long-term resource needs, and the solicitation will not be limited to conventional supply-side resources. Cost-effective renewable, energy efficiency, and demand-side resources would all compete on an equal basis, with adverse environmental effects of new resource acquisitions being considered minimized to the extent practicable.

Western's past experience in the marketing of power has shown the pitfalls of entering into inflexible long-term contracts with fixed capacity and energy commitments. In response to this experience, Western needs to develop contracting policies that respond to changing circumstances. While Western has carried out the role of acquiring firming resources on behalf of its customers in the past, I have directed Western to design contracts which allow customers to take on this responsibility in the future. Whether Western or its customers carry out this role in the future, there should not be a dual standard in planning for and acquiring resources. The acquisition of resources in support of Western's hydroelectric commitments should be based on integrated resource planning principles, with cost-effective renewable resources, demand-side management, and energy efficiency being treated as viable alternatives to the purchase of firming energy.

The draft EIS does analyze the environmental impacts in Western's region of purchases in support of hydroelectric sales. Purchases by the Central Valley Project are assumed to continue throughout the analysis period. For other projects, the draft EIS reflects the fact that energy is marketed on a long-term average water availability basis. That is, in bad water years, Western needs to purchase firming energy in order to meet its contractual obligations. In good water years, Western generates surplus energy which is sold to customers and other regional utilities. Energy purchased by Western from regional utilities in bad water years is often generated by thermal plants. Sales of surplus hydroelectric energy are typically made to regional utilities with fossil fuel-fired generation; these sales reduce the need for operation of thermal plants, resulting in lower emissions. The reason for Western's purchases is to convert the variable hydroelectric resource into a stable and reliable firm resource.

Most of Western's purchases support the marketing of power from the Central Valley Project. Western is currently in a public process to determine how Central Valley Project power will be marketed after current contracts expire in the year 2004. If adopted, certain alternatives being evaluated under the Central Valley Project EIS could reduce the need to purchase power for that project.

The information asked for in the second paragraph of the Chairman's question is displayed in the following table:

PERCENT OF FIRM ENERGY FROM FOSSIL-FIRED GENERATION

	PSMBP	CVP	SLIP	LAP	PDP	WESTERN TOTAL
1993	34.9%	52.1%	18.7%	8.8%	1.4%	27.7%
1992	19.4%	65.5%	25.6%	9.7%	0.8%	28.6%
1991	11.7%	49.0%	24.5%	15.3%	0.0%	21.1%
1990	14.0%	56.7%	22.0%	11.8%	0.0%	22.0%
1989	3.7%	58.4%	25.6%	*	0.0%	18.7%

Note: PSMBP - Pick-Sloan Missouri Basin Program, CVP - Central Valley Project, SLIP - Salt Lake City Area/Integrated Projects, LAP - Loveland Area Projects, and PDP - Parker-Davis Project.

* LAP WAS NOT CONSOLIDATED UNTIL 1990

The following table provides a broader historic perspective on Western's actual purchased power. Unlike the first table, the percentages displayed below represent purchases from all sources, and not just fossil-fired generation. Percentages for 1984 and earlier reflect Western's total (firm and nonfirm) energy sales, while those for 1985-88 reflect firm sales only.

TOTAL WESTERN PERCENT PURCHASED ENERGY
PRIOR TO 1989

	PERCENT PURCHASE POWER
1988	21.1%
1987	15.8%
1986	13.6%
1985	15.0%
1984	7.1%
1983	8.8%
1982	15.0%
1981	16.7%
1980	12.2%

Question 4. "In the past, WAPA officials have stated that there needs to be linkage between IRP and contract extension in order to provide WAPA customers with the certainty they need to conduct IRP and acquire new resources. Amongst the alternatives analyzed in the DEIS is extending Loveland and Salt Lake City power contracts that expire in 2004 from 10 to 35 years. Therefore, under the various alternatives these particular contracts would be extended until at least 2014 and as long as until 2039.

Is it current utility practice to invest in supply or demand side resources for electricity needs that may exist 20 years from now (2014) or 45 years from now (2039)? If not, is it necessary to act now to extend contracts for the purpose of facilitating IRP?"

Answer 4. No utility would invest in resources in 1994 to meet load growth predicted to exist in 2014 or 2039. Long-term planning horizons for formal state regulatory IRP filings generally range from 10 to 20 years. The lead time for development of resources varies depending upon the resource selected. The Program draft EIS estimates that new supply-side and demand-side resources could take from 3 to 10 years to implement once the acquisition decision is made.

However, due to the time required, a utility may invest today in a long lead-time resource necessary to meet a resource deficit in the next 6 to 10 years. Certainly, a utility would be actively planning today for such a resource. If Western's resources are not extended to current customers, replacement of Western's hydropower with another resource would be a high priority for the customer. The replacement of the base-load Western resource is predicted to result in environmental impacts and may influence the ability of that utility to invest in cost-effective demand-side management and renewables to meet future load growth. The longer the term of Western's commitments, the less need there is for resource planning to replace Western's renewable, nonpolluting resource, and the more time and resources are available to consider and implement demand-side management, energy efficiency, and renewable resources to meet future needs. One Western customer, recognized as a leader in IRP and demand-side activities, commented that "[r]enewable resources, in particular, can require a longer period to amortize, and thus [would] be easier to select when a dependable cost-effective long-term resource complements them in a customer resource mix."

The key policy issue raised in the Chairman's question is the timing of decisions on resource commitments. Quality integrated resource planning is enhanced when a customer knows what resources are dependable in the future. To enhance customer IRPs, the Department supports the position that decisions on resource commitments should be timed to facilitate certainty.

Question 5. "In its comments on the DEIS, the Bureau of Reclamation states:

> 'Reclamation is concerned that the power contract extension alternatives proposed by Western may create unrealistic expectations regarding future power allocations amongst Western customers, which may be difficult to satisfy in the event of future changes in the operations of Reclamation Dams. The recent controversy regarding changes in Glen Canyon Dam operations demonstrated that although Reclamation retains control over dam operations, the expectations of Western and its customers, that a certain amount of power will be produced by a dam make it much more difficult for Reclamation to exercise its discretion to modify dam operations.'

In light of the Bureau's concerns about the environmental consequences of creating unrealistic expectations of future power allocations, is it prudent for WAPA to make power allocations decisions in 1994 for contracts that will expire 10 (Loveland, Salt Lake City) to 23 years (Hoover) from now?"

Answer 5. I agree that it is too soon to make power allocation decisions for the Parker-Davis Project and the Boulder Canyon Project. No proposal to extend resources should be implemented for these two projects until a later date. For the projects with contracts expiring in 2004, the new marketing policies will be implemented subject to changes required by specific project requirements.

The Chairman has made an important point concerning how expectations can be unfulfilled if resource changes are required. Western's power marketing policies must be very explicit so as to not create unreasonable expectations regarding the availability of hydropower in the future. Under the alternatives featuring an extension of resource commitments, Western would extend to existing customers a percentage of the resource available when existing contracts expire, not a percentage of the resource that is being marketed today. Changes in the operation of Reclamation's facilities can be accommodated through this approach. For those extension alternatives set forth in the Program's draft EIS, Western has reserved the right to adjust its marketable resources on a fixed-window basis or on 5-years notice. This allows Western to react to longer-term changes in operations or hydrology, and provides considerably more flexibility than under current contracts.

Proposed changes in operations at any Reclamation facility from which power is marketed will give rise to public debate about the issues involved. This is the essence of any public process regarding the management of Federal facilities. Unlike most existing marketing plans, once the decision on operational changes has been made, Western would have the contractual right to adjust the marketable resource. Western's customers have been told repeatedly in the Program public process that this flexibility is needed.

Question 6. "The DEIS only considers power allocation options that involve reserving between 90 and 100 percent of the available power resource for WAPA customers. The DEIS does not analyze the environmental effects of any alternative power allocation regimes, including the following:

* providing power to preference entities that do not currently receive WAPA power such as Indian tribes and others;

* increasing the power provided for the pumping of water for fish and wildlife purposes; and,

* increasing the power allocations of WAPA customers who maximize the environmental benefit of their current allocations through energy efficiency and other measures.

Shouldn't the DEIS be modified to analyze these alternatives?"

Answer 6. Western fully supports the allocation of its marketable hydropower resources to new customers, including Native American utilities and other eligible preference entities. Western also endorses the use of hydropower to pump water for fish and wildlife purposes, as well as other public purposes.

The draft EIS addresses the issue of new customer allocations by analyzing the environmental impact of creating project-specific resource pools. In this manner the environmental impacts of allocating the resource to new customers can be quantified since it is uncertain how many, and at what locations new customers will apply. The resource pools could also be used as an incentive to reward existing customers who maximize the environmental benefit of their current allocation.

Project-specific resource pools would be created from power currently committed to existing customers, but not extended. If adopted, resource pools would be allocated on a project-specific basis pursuant to a future public process. Specific criteria for allocation, such as those suggested in the Chairman's question, would be developed at a later date, in a full and open public process, and any necessary environmental documentation relating to new customers would take place at that time. The resource pools identified in this process are up to 10 percent. However, if during the project specific public process a larger, or smaller pool, size is appropriate, adjustments can be made at that time.

Question 7. "What is the contract length for current Pick-Sloan, Loveland, Salt Lake City, Central Valley Project and Parker-Davis contracts? How far in advance of the expiration of previous contracts were these current contracts signed?"

Answer 7. Contracts for the Pick-Sloan Missouri Basin Program-Eastern Division were for 15 years under the currently effective marketing plan. The marketing plan took about 2 years to develop. Currently effective Eastern Division contracts were signed between November 1980 and January 1981, about 4 years before the previous contracts expiration date of January 1, 1985.

Contracts for the Loveland Area Projects are 15 years in length.

The marketing plan took about four years to complete. Currently effective contracts were signed between April and September 1987, over 2 years before the previous contracts expiration date of October 1, 1989.

Contracts for the Salt Lake City Area/Integrated Projects are 15 years in length. Development of the marketing plan started with a public meeting in May 1980, and a draft EIS on that power marketing plan is currently under public review. Currently effective contracts were signed in March, 1989, about 6 months before the previous contracts' expiration date of October 1, 1989.

Current power contracts for the Central Valley Project range in length from 10 to 40 years, with an average term of about 23 years. All currently effective CVP contracts expire in the year 2004. Contracts for one-third of the CVP power would have expired on July 1, 1994, but were extended 10 years, pursuant to the post-1994 CVP marketing plan, effective upon execution in October 1992. Ten-year contracts for new CVP customers receiving power under the post-1994 marketing plan were executed over the last 9 months and will be effective on July 1, 1994.

Current power contracts for the Parker-Davis Project are 20 years in length. The marketing plan development started in November, 1979, and ended when final allocation criteria were published in

1979, and ended when final allocation criteria were published in July, 1987. Contract signature dates vary, depending upon the expiration dates of previously existing contracts.

Mr. Chairman, this concludes my remarks. If you or members of the Subcommittee have any questions, I would be pleased to answer them.

Mr. MILLER. Mr. Beard.

STATEMENT OF DANIEL P. BEARD

Mr. BEARD. Mr. Chairman, I don't really have a statement. I sat here—stood, actually—here this morning and listened to the testimony, and I guess there are just a couple of comments that I would like to make, the first of which is Secretary White has, I think, underplayed the significance and importance of his testimony this morning.

This testimony was arrived at after considerable discussion, and I think I would like to pay a compliment to him and to his staff for the hard work that they have put in on this statement. It really reflects a very thorough attempt to look at the problem and to come forward with, I think, a very unique and innovative set of solutions. So I would really commend that to you and the other Members.

As I was listening this morning, I think there were two things that were overlooked by the witnesses and by the discussions, and I would like to really throw those on the table, because I do think they are important.

The first is that a fundamental concept of the policy that we have been operating under in this area is that power is secondary to the water resource needs of the individual project, and I don't think anybody wants to question that. But I think it is important to point that out, because as we sit and talk about power, it is important to understand the relationship that goes back and forth between power production and water production, and as water resource policies change, it is going to inevitably have an impact on power production and the availability of power.

And I think the second concept that was overlooked is really we are playing an end game here in one sense. And that is because the amount of supply that we have available in the system is really limited. We haven't really significantly increased that, and I don't know of anything that is underway that is going to significantly increase it.

I do know of some things that could decrease the supply. I mean, we are starting out with Western at least with about 10,000 megawatts, and there isn't anybody's expectation that is going to jump to 20,000. In fact, it is probably going to move from 10,000 and move progressively down as, you know, equipment wears out. We will rehabilitate that equipment and try to keep it going, but some of it is aging, and we are not building new hydroelectric power generating facilities in any great way.

The challenge that Western and Reclamation are really faced with, and I think the reason the testimony is so important, is that what we are really trying to do is handle predictability and certainty for power customers, and we are trying to balance that against the sort of imprecise nature of future water supplies and resource conditions and resource decisionmaking, and it is that constant tug and pull between giving somebody some certainty and grappling with the problems of uncertainty and in a changing world. And I guess that is what my letter to Western pointed out and my comments on the draft EIS, and I would like to put a copy of that in the record.

Mr. MILLER. Without objection.

Mr. BEARD. My concern is that we not create a sense of unrealistic expectations on the part of Western customers as to how much power will be available. And I think it is very important for me in my role as a water resource manager and power generator to highlight that, because it is this problem of creating expectations that comes right back here.

You had a discussion earlier today about Glen Canyon Dam, and I think that it is important to point out that that issue didn't get resolved; there were significant expectations and significant debates that took place and it didn't get resolved until there was an act of Congress.

Well, if we have to have an act of Congress every time we want to change the water supply operations of a hydroelectric facility, this committee is going to be rather busy. I think that the changes that Secretary White is recommending and that Western is going to be pursuing will help us resolve that, and be able to deal with future problems in, I think, a way that will allow us to deal with them quicker and faster.

Again, I don't have a statement; I would like to put the letter in the record, and I appreciate this opportunity to be able to comment, and I would be happy to answer any questions.

[The document follows:]

United States Department of the Interior

BUREAU OF RECLAMATION
Washington, D.C. 20240

IN REPLY REFER TO:
W-1000

MAY 17 1994

Mr. William Clagett
Administrator
Western Area Power Administration
P.O. Box 3402
Golden, Colorado 80401-0098

Dear Mr. Clagett:

The Bureau of Reclamation (Reclamation) offers the following comments on the draft environmental impact statement (EIS) for the proposed Energy Planning and Management Program.

Reclamation supports program alternatives 11 and 12 which do not address power contract extension and power allocation issues. Reclamation supports these alternatives because it is far more practical and environmentally sound to make power contract extension and allocation decisions on a project-by-project basis, as Western has done in the past. In addition, a project-by-project approach will make it much easier for Western to coordinate its efforts with those of Reclamation.

Reclamation is concerned that the power contract extension alternatives proposed by Western may create unrealistic expectations regarding future power allocations amongst Western customers, which may be difficult to satisfy in the event of future changes in the operations of Reclamation dams. The recent controversy regarding changes in Glen Canyon Dam operations demonstrated that although Reclamation retains control over dam operations, the expectations of Western, and its customers, that a certain amount of power will be produced by a dam make it much more difficult for Reclamation to exercise its discretion to modify dam operations.

Furthermore, it would be imprudent to establish generic power allocation policies when Western does not know how much power will be available to market from a particular project and what entities will desire to purchase the power. For example, Western proposes in the draft EIS that its Loveland Area Projects power customers, whose contracts expire in the year 2004, receive between 90 and 100 percent of their current allocations when their contracts are renewed. In Reclamation's judgement, insufficient information is available to Western to enable it to make a sound decision relating to contracts that will expire 10 years from now. The draft EIS even proposes "possible further application" of the above-mentioned contract extension/power allocation regime to the Boulder Canyon Project, whose power contracts expire in the year 2017. It seems unlikely that

Western has the ability to predict, with any degree of reliability, how much power will be available from this project 23 years from now, or to determine how the power should be allocated.

Western's contract extension/power allocation alternatives may also unduly limit the ability of both the Interior and Energy Departments to resolve future resource problems in the West because they essentially lock in the current allocation of power from Reclamation and the Corps of Engineers projects. For example, it is quite possible that, in the future, Indian tribes involved in water rights litigation could seek a power allocation from Western as part of their settlement. Program alternatives 2 through 10, which guarantee current Western customers between 90 and 100 percent of their current power allocations, may make such an arrangement impossible. Western's proposals to lock in current power allocations could also limit the future ability of the Government to provide additional power for fish and wildlife purposes, such as pumping water to wildlife refuges.

The basic conclusion of the analysis in the draft EIS appears to be that the more electric power current Western customers receive, and the longer the contract extension, the better the result for the environment. The basis for this conclusion is that increasing the certainty that Western customers will continue to receive resources from Western will lessen their desire to construct new energy generation facilities that utilize fossil fuels.

The analysis in the draft EIS does not support this conclusion because the document contains no analysis of the environmental affects of alternative power allocation regimes. The following are just a few alternative allocation regimes that were not analyzed in the draft EIS, which Western should consider in the final EIS:

- The environmental effects of rewarding Western customers that conserve energy resources with a larger power allocation.
- The environmental effects of providing Western power to preference and nonpreference entities that do not receive power from Western currently that intend to meet future power needs with fossil fuel-fired generation.
- The environmental effects of providing more Western power for fish and wildlife purposes.

The draft EIS also does not analyze the environmental effects of increasing the price of the power provided by Western. Some observers believe that low-priced Federal power provides a disincentive for Western customers to aggressively pursue opportunities to increase energy efficiency.

Reclamation believes that it would be far more practical, and environmentally sound, for Western to make power contract extension and allocation decisions on a project-by-project basis, as it has done in the past. In the long run, handling these matters on a project-by-project basis will provide greater certainty for Western customers because the allocation decisions will be based upon the actual conditions and problems that exist at each project. This is preferred over a generic approach that may not ultimately work for a particular project and may not be consistent with Reclamation's operation of the project. Consequently, a project-by-project contract extension/power allocation approach will make it much easier for Western to coordinate its efforts with those of Reclamation.

We appreciate the opportunity to provide comments on Western's draft EIS for the proposed Energy Planning and Management Program.

Sincerely,

(sgd.) J. Austin Burke

For Daniel P. Beard
Commissioner

bc : W-5000, D-5000

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Mr. MILLER. Well, thank you very much for your testimony to both of you, and I think it helps us hopefully resolve some of these differences at a lower temperature over the coming months.

One of my concerns, and I don't know, Secretary White, if you were here or not, is that I talked about it with the earlier panel, was that these systems are impacted by, as I think Mr. Beard knows all too well, and certainly you do too, by a series of laws of which were not contemplated and/or considered during the last round of contracts for the most part, and/or the creation of the system, endangered species and other environmental concerns, and new claimants for access to these systems that were not considered. It is not that they were considered and rejected in many instances; they simply were not considered; they didn't have the political wherewithal to sit at the table, whether it is the Native American interest and/or the environmental interest or others. They were not part of the construct that came to the Federal Government and said, build this system and we will thrive. It didn't work that way.

But now as their claims mature and become ever more legitimate in the public's eyes, the extent to which they have to run up against a hard and fast contractual obligation and the obligation of the Federal Government and the expectations that are created, as Mr. Beard said in that contract, they are disadvantaged in sitting at the table, that they may very well have had a seat in the first go-round.

Again, in some instances we are talking about potential claimants that I am not aware of and that we are not aware of as we sit here together today in terms of future environmental considerations. And the question is, how do we use these contracts to provide both the certainty and the stability that the first panel testified about and these other competing claims on those very same contracts?

And obviously, each and every one of these regions is a little bit different in terms of its expected growth and the types of customers that they now serve. But that issue, I think, is the same throughout the entire system.

In some ways, if you were to add a new customer and you had to go out and purchase power for that customer, you might consider that a very positive event. You are getting economic activity and you would meld that through the costs.

If you say you need that for environmental protection, it is viewed as a negative event because you have to go out and purchase the replacement power, and you can see immediately how the dynamics of that argument within the public policy arena changes.

And yet, had we thought about or known about—in many instances we simply didn't know about those potential environmental claimants—we would have allocated power differently then?

Mr. WHITE. Yes.

Mr. MILLER. And you know, that is a fair burden to scale in this day and age and yet those commitments must be met. But as Mr. Beard says, if in fact that means that you have to come to the Congress each and every time, and/or you have to look down the barrel of 15 or 20 years of litigation, then I suspect we don't have a policy to accommodate those. And I would like to have your reaction. I think it is within the realm of the statement that you have already submitted to us and your comments.

Mr. WHITE. Yes. I think, just to build on what you are saying, if history has taught us something since the time, say, that the Central Valley contracts were let, it is that the economics and demographics of the West can change; the sources of other power available to many of these utilities can change. What we need to do is strike the right balance. That is what you are trying to do; that is what we are trying to do. It is not being doctrinaire. I mean, if we abrogated all contracts tomorrow we would have more flexibility, but we certainly would not help the ecology of the West.

Here is how I see that balance. Very clearly we ought to be having discussions based on the percentage of the resources that will be available and be very clear, as clear as one can be, concerning the different demands that will be placed on the system.

Now, let me just put a footnote here. Intelligently run hydro power, in my experience, in the energy business, can be a very environmentally benign source of power, so we don't need to always operate on the most pessimistic assumption concerning its availability or supply.

When people come in with a bargaining position, as a matter of law, and say, "we expected more would be available when you said a percentage would be available", we need to make a clear record and to communicate effectively concerning what those risks are, so that the individual utility and user will know what it is getting into.

I might add, if those risks are exaggerated, that we don't want it to backfire and have that utility do something that itself does not make some sense, if they had a hydro power resource available that had fewer emissions.

The second thing we need to do is the very best planning that we can. This is why the integrated resource plan on supply done by Western for its own supplemental supply, is important. It is important for us to plan the best we can and figure out just what the competing claims on that power are likely to be, not for some short period of time, but through a reasonable utility planning horizon. And that includes tribes.

I have said in the statement, and I will say right here plainly, that we are open to working with tribal entities to come up with contractual arrangements that could allow them to use some of the power that is available.

In many of the areas in which we operate, although we can't say for sure what the exact level of demand will be, I think somebody can do some planning well into the next century and we ought to be doing that, because we have to do it for our own purposes anyway.

So that is a general reaction to what you say. What I would like to do is work with people to come up with demand estimates on the basis of what the best forecaster numbers that we have available, and not simply have either Western or anybody else pick numbers out of the air.

Mr. MILLER. Thank you.

Am I correct in understanding that currently you are doing separate EISs for the allocation from the Colorado River and CVP? Is that correct?

Mr. WHITE. I think there are separate marketing plans EISs in most project areas as well as an overall Energy Planning and Management Program (EPAMP) EIS.

Mr. MILLER. Can you explain for me that relationship then?

Mr. WHITE. Well, the world of EISs is one that I learned quite a bit about the last year and what supersedes what and the like. Somebody may have to kick me from behind, but this is the way that I understand it, is the Western-wide-EIS will address the issues which occur on a system-wide basis, and the individual marketing plan EISs will build on that and complement and address issues in more detail in the particular project areas. If there is a better way to do it, I am sure people are open to suggestions as long as it is legal.

Mr. MILLER. Do you expect to be doing individual EISs in each, as contract renewals come about?

Mr. WHITE. For each contract? I would say we expect to do EIS's on each project there is an ongoing EIS process, and I think that should be continued. There are unique issues in each of these areas.

Mr. MILLER. But on the overall system on the EIS, you are in the final stages of that, correct?

Mr. WHITE. Yes.

Mr. MILLER. Okay. I guess my concern is that we fully—and again I am not characterizing it, I am just raising the concern—look at a system like the CVP or Colorado that the process fully allows those competing interests at that stage which it is much better to characterize those issues at that level than to try to believe that they can be characterized properly or in the proper perspective in the overall EIS.

Mr. WHITE. Well, I think, the principle that——

Mr. MILLER. Competition on a West-wide basis may not be the same competition that you see within the Colorado system and/or within the CVP system.

Mr. WHITE. I agree, and that is why people better use some common sense about how these things fit together. We ought to try to figure out the issues which are on a project-by-project basis—unique issues or variables that have to be considered for that project—and allow full participation in that process on a project-by-project basis where that is appropriate.

Mr. MILLER. You have some contracts in the Hoover that, what, are 2017? The EIS you do today, the overall EIS may not have much relationship to that system at that time.

Mr. WHITE. You bet. I agree with that. We have contracts which expire by 2000, 2004, and then well out in the two-thousand-teens. On the latter I couldn't agree more. I don't think we should be making premature decisions about that when we will have a much better view of what that world will be at a time that is well into the future.

Mr. MILLER. Mr. Beard.

Mr. BEARD. No. I was just going to comment that I support the project-by-project EIS approach, but I also think that the system-wide EIS has been extremely valuable. I mean, these hearings are just a good example. They have focused all of us on the policy and the policy approaches that we want to take in this area. And it does affect all of us, and I think it served a very valuable function in that regard.

Mr. MILLER. Mr. DeFazio.

Mr. DEFAZIO. Thank you, Mr. Chairman.

I am sorry I came in late; I had some constituents I had to see, so I missed the summary of your testimony. But in reading quickly through Mr. White's testimony, when you get into page 9 of the discussion there are a couple of points, a resource pool of up to 10 percent. Now, this is where we heard the testimony earlier about the 98–2 percent split. Are we talking about the same thing here where the customers are opting or saying that they would like to see a 2 percent pool or reserve, and you are talking about a 10 percent reserve here?

Mr. WHITE. Yes, the resource pool will depend on different areas. I believe there is one area where, given the demand growth or lack of demand growth and other sources of supply, it is more like 2 percent reserve. But this is where, Congressman, I think we need to look and do the best forecast that we can concerning what the percentage is we need to reserve to take into account the plausible alternative claimants.

Mr. DEFAZIO. Okay. But I was looking later in the testimony at the amount of purchase power, and in the eight-year period you give us, it only goes up to 1988. You are only below 10 percent in two years?

Mr. WHITE. Yes.

Mr. DEFAZIO. I mean, I understand the customers' demand or needs for the largest fossil assurance. I mean, the question is how much permanent, ongoing burden should you assume in terms of melding in expensive power into your lower cost base as opposed to how much of that responsibility should the customers demand, you know, assume in terms of their demand on the system? If we go to this 98 percent, there is no pool now or reserve as such.

Mr. WHITE. Yes.

Mr. DEFAZIO. They are 100 percent allocated essentially.

Mr. WHITE. I think that is right in most areas, but I don't think that is what accounts for some of these numbers.

I think you have put your finger on this very important issue, and that is, "what is WAPA's role, as opposed to the role of the customers in coming up with supplemental power?"

Future contracts to balance the fluctuating amount of electricity you get from a hydro project which could vary seasonally and within a much shorter period of time. This is the way I see it, and this is what I have told the administrator. Customers ought to have a clear option, and know they have an option, of trying to offset the fluctuations in the hydro power from other sources.

I mean, I want to say, number one, we are not an empire building here. If, on an integrated resource plan a utility wants to provide for balancing out the peaks that you get from the hydropower system, it ought to do it.

Then the question becomes, what do you do with many of the customers we have, such as Congressman Williams talked about, where they are small and they are really not equipped to be going out and purchasing a lot of power. They obviously will band together somehow to take care of that need. Should we prevent them from dealing with WAPA and their contracts in taking care of that need, or would we be better off economically or environmentally if they chose to deal with WAPA on that?

I think it is critical too that WAPA will engage in some integrated resource planning, looking at efficiency, renewables and other alternatives, as a way to supplement that swing in hydro supply, because that is why a lot of this power will be needed. Even if you had 98 or 100 percent allocation, that does not dictate the level of your alternative power purchases. That is, to some considerable extent, a function of the flow of the river. What we would like to do is move—make it clear that customers can go out and supplement that.

We don't want to get ourselves in the same position that we did in the Central Valley Project, where people were counting on other sources of power. In the 1960s, those contracts were way too long, and they were firm commitments for a firm amount of power. But we do want to allow people to continue to go to Western, it seems to me, and put together a package which will allow them to supplement the hydro power that they purchase so as to level out that source of electricity. I don't know whether that is a clear enough answer or not.

Mr. DEFAZIO. Well, if I were, then, it seems to me the contracts might be more variable rather than uniform, and, say, you have a goal of reducing some of the demands on the system; you want to determine to have a vigorous demand side management program, it obviously has to be implemented somewhere. I mean, perhaps a customer came to you with that sort of a proposal? I mean, this is beginning to sound to me sort of like some things BPA is proposing in the unbundling of rates and services sorts of things. I mean, how would you fund or encourage that utility in your rate structure, or in your rate? Your demand allocation to that utility? I mean, how are you going to favor them or encourage that sort of activity which would have an end result that is desirable to you, which is lowering the total demand on your system and being able to meet your other customers' needs.

Mr. WHITE. Let me say this is not like the tiered rates that BPA is talking about.

Mr. DEFAZIO. We don't know what the tier grades are that BPA is talking about.

Mr. WHITE. This is not a movement or a desire to move away from conservation.

My point is this: How do you encourage your customer? If a customer is faced with a variable hydro source of power, they will have a need to balance that with some other source: demand side management, storage technologies, other sources of supply. Both at the customer level and at the Western level, we want to make sure that integrated resource planning and least-cost alternatives are pursued to accomplish that balancing function. I don't think the balancing function or the need for balance, is going to end.

Mr. DEFAZIO. Just one other thing. If I were the end-user, I would want to shift the burden on to you as much as possible, because when you purchase across your system, you know, I am getting essentially a melded rate as opposed to when I have the individual responsibility of going to my avoided cost acquisition.

What I am saying, I mean the question is, how are you going to get away from just purchasing more power which you have had a history of, you know, significant purchases over at least the 10-year period reflected here and get more toward the demand side management in this new contract? I mean if I am an individual utility, I am going to want to say, hey, you know, give me all of this power and you go out and fill in the gap here, and I prefer you fill it in by purchasing, and I get my melded rate because that is not going to have very much impact on me.

Mr. WHITE. I understand your question. You raise a good question. I am not sure I can tell you about how the rate structure may create a bias against conservation and we don't want that to occur. Let me follow up with you on that.

In general, I would say that we want to have least-cost principles applied to both the customer's decisions and Western's decision of how to balance that fluctuating source of electrical power from the hydro system. Part of that ought to make sure there aren't perverse pricing incentives.

Mr. DEFAZIO. Mr. Beard, if I could just ask you something that just tweaked me a little bit. We have had some problems with the Corps of Engineers with the northern climes where they have facilities which beg maintenance overhaul, generators that are running 20 years past their overhaul date, but running very reliably; where we got authority for the Bonneville Fire Administration to make those investments in terms of upgrading those facilities to increase their reliability and their actual capacity?

I am curious, what, since you mentioned some of the uncertainty about what is available in the future comes from some things wearing out, degradation and that, I mean who and how are we funding those replacement and maintenance now? Are you subject to the constraints and the whims of the Federal budget process?

Mr. BEARD. Yes and no. It depends on the area. We are working with Bonneville to do a similar kind of approach where they are going to finance some of the upgrading and some other work. In other projects, we run it through our operation maintenance budget, so it depends.

Mr. DEFAZIO. So I am wondering, in the WAPA case you say you are working with BPA. Are you working with WAPA in a similar manner?

Mr. BEARD. No, we are not. There are some exceptions. Hoover is one exception. But I think, you know, again it goes back to the individual authorizations and the way that we handle it. For the most part it has been done through our operation and maintenance budget and then also Western has a similar kind of budget for their facilities too.

Mr. DEFAZIO. I am aware that the Vice President in some of his reinventing government musings has proposed some fairly radical ideas, such as, you have a facility, it could be upgraded to produce more power; let a private interest bid on that and come in and do the work. Is that something that the Bureau of Reclamation has been looking at?

Mr. BEARD. No. Interesting idea, but no, we haven't looked at it.

Mr. MILLER. Would the gentleman yield?

Mr. DEFAZIO. I will be happy to yield.

Mr. MILLER. If in fact you wanted to do that or you wanted to install more efficient equipment for your own part of this planning process system-wide, are you capable of, under current authority, to put that into the contract price? I don't know if it is just figured as O&M or whether if you wanted to buy a more efficient generator those kinds of efficiencies be put into these contracts when they are renewed?

Mr. BEARD. I don't know. I think I would rather defer to Mr. Claggett or somebody from Western with respect to the individual contracts. We have operated our facilities essentially as Federal facilities. I mean, we generate the power essentially with Federal employees and we market it essentially with Federal employees, and we may be approaching the day where we have to sit down and think about whether or not that is the right thing to do in the future.

Mr. MILLER. I am not raising so much that question. My question is that some of these facilities have generators in that were put in a number of years and generation technology has changed dramatically. But the issue is, you are asking your customers and they are asking their customers to engage in energy efficiencies and so forth. And avoidances. We avoid that because you don't want to come and ask for an appropriation to do that, whereas if it could be figured into the contract price, perhaps that could be done.

I am not asking the question of who is operating, but just whether or not there is room for that or maybe that is not an issue, because it is all state of the art.

Mr. DEFAZIO. If the chairman would yield back. In the BPA case, the idea is we are not removing these from the Corps' jurisdiction, but BPA is going to continue to have Corps' employees operate them, who do an excellent job, by the way. I don't know how you get better than 98 percent reliability, you know, out of these projects, particularly some aging projects.

But I think the chairman is getting to the heart of this, which is are we deferring some decisions that would be prudent to upgrade some of these facilities which would address some of the issues we are going through here without any detrimental environmental impact because of budgetary constraints and do you have the authority to deal with that, or do we need to look at that?

Is there some way that you can be entering into agreements, say, with the customers, like here is a pretty big investment we would like to make; it will provide for this much more reliability or this much more capacity, whatever it is going to do?

But, frankly, we can't get an O&M budget, and we would like to see the customers carry this burden in the contracts and everyone is going to benefit from it.

Mr. BEARD. Well, I think the answer to your question from our perspective is we could do that. I would like to supplement my answer for the record. But in a general manner we could, through the Contributed Funds Act, and we could provide you with those for the record, there may be instances where we have done that.

As a matter of policy for the organization itself, that hasn't been the sort of overriding direction. But it could well be. And I think your first question was, is our operation and maintenance budget constrained, or are operations and maintenance of facilities constrained by our budget, and the answer is yes. I think that it is very clear that it is.

The operation and maintenance budget that we have been going up as opposed to our construction budget which is declining, but still it hasn't gone up to the extent that it probably should if we wanted to operate and maintain these in a pristine condition. But, you know, budgets—we do suffer from that problem.

Now, I don't think that any of the facilities are in a position where they are dangerous, but on the other hand, have we done the best that we possibly could, if we had unlimited amounts of money, the answer is no.

Mr. DEFAZIO. Well, I guess my concern is that—this is certainly interesting, the Vice President's proposal—if they say it was contracted out and the winning entity is a private entity as opposed to dealing with public preference and public projects who generate the power.

So I mean I think that it would be desirable to have some capability to enter into agreements with the public customers to enhance the system in order to better meet their needs and help for you for some of your budgetary constraints. I would be interested in any further explication that you can provide.

Mr. WHITE. Congressman, in the Global Climate Change Action Plan they address this idea of providing some private project financing for the upgrades. Public power people came to me and said, if there are any high return on investment or good return on investment upgrades, that the public systems ought to be able to do it. I had a meeting three weeks ago with Bonneville, WAPA, our policy people who put that in the Global Climate Change Action Plan, and asked the specific questions: "What are the upgrades for which there is a market? Identify them, and then tell me whether or not there is public money to do it." Just the same question you are asking. The public power folks say that there is enough money to do it. We imply in the Global Climate Change Action Plan that if there is not, the private sector ought to come in. This has the risk and the problem that you raise. I would ask Mr. Clagett to make sure that we wrap that up quick and get some answers to this Subcommittee and the staff on this.

Mr. DEFAZIO. Thank you. Thank you, Mr. Chairman.

Mr. MILLER. Let me raise an issue with the previous panel, Mr. Secretary, and that was on the issue of Native American utilities. Is that a condition precedent to them having access to power in the future that they have got to form a utility or look like a utility?

Mr. WHITE. Well now, here I am not a lawyer specializing in this area, but I will tell you that we do want to develop the contract provisions that would allow tribal uses of this power. Perhaps Mr. Clagett can tell me whether that is a term of art and what the qualification should be on that.

The objective is to be able to meet some tribal needs, and we will try to work through how we will go about that. I don't know whether it means dropping the utility requirement or making an Indian utility, but we will get back to you concerning exactly what the process is.

[The information follows:]

Western will not require utility responsibility for all new preference power customers receiving allocations of Federal Power. Many Federal agencies, including DOE installations, have enjoyed preference status, as end users, even though they have no utility responsibility. DOE plans no change in the status of such Federal agencies. However, it is Western's policy to give preference in allocating power to municipalities that have utility responsibility. A recent court opinion found Western's interpretation of Congressional intent supporting this policy for municipalities to be "fully reasonable." *Salt Lake City, et al.* v. *Western Area Power Administration, et al.*, No. C86–1000G (C.D. Utah Apr. 14, 1989), slip op. at 40, aff'd, 926 F.2d 974, 978 (10th Cir. 1991).

As for Native American Tribes, the Bureau of Reclamation concluded in 1961 that the Navajo Tribe qualified as a preference customer under § 9(c) of the Reclamation Project Act of 1939. Western has always considered Native American Tribes as preference entities. Proposals for providing allocations directly to Native American Tribes will be developed on a project-by-project basis, during the allocation of project-specific resource pools. This flexibility is critical since an allocation of power is of no value unless an organization has the means to receive power; the potential customer must be ready, willing and able to take delivery of power. If resource pools are part of the proposed EPAMP rule, they will be sized to include proposed allocations to Native American Tribes.

Many Native Americans receive hydroelectric power benefits from Western today. Western has directly allocated power to tribal utilities or tribal irrigation districts. Western also has allocated power to cooperatives that, in turn, serve many tribal loads. Lower electrical rates are paid by tribes served by utilities receiving power from Western. Either directly or indirectly, Western's allocations benefit 45–50 tribes throughout the west. In the Eastern Division of the Pick-Sloan Missouri Basin Program, Western estimates that approximately 30 percent of the total Native American load on tribal reservations is met through Western allocations of power to cooperatives serving these reservations.

The page in the draft EIS referenced by the Chairman's question will be expanded to clarify Western's policy.

Mr. MILLER. I made the point with the previous panel that the rapid transit district in my district is an end-user in the San Francisco Bay area and up in Sacramento, and somebody said those are things that we inherited. Well, we inherited the Native Americans, too, and we just sort of want to even up what the hurdles are going to—I know you think you inherited us, but in terms of responsibility. In terms of responsibility, we inherited this, and I just don't want to set up some hurdles that are insurmountable when the intention is to figure out how you can meet those demands within reason. I just don't want some artificial arrangement created so that we don't quite get to the point of deciding yes or no, is there going to be access or an allocation or what have you.

Mr. WHITE. This is such an important issue, and I met with tribes when I went out to visit with people in the Western area and I had people bring some average utility rates. There are tribes in the West that are paying 9, 10 cents per kilowatt hour in the western United States, prime targets for energy efficiency. After I found this out, I approached the leaders of the President's National Service Corps and said "we need to earmark some people to go out there and start doing energy efficiency audits." And they have. I think this issue of tribal power is a very serious issue.

Mr. MILLER. Well, I think it is important. As a matter of fact, I will tell you that I think it is very important, because a number of these projects exist, and as Mr. Beard knows, when we go back through some of these projects, when you go back through the history, the Native American community was used as a major rationale for developing a number of these projects, as we found out when they went back to Garrison. It is just that they weren't going to get the benefit until everybody else was satisfied, and this committee is not going to allow that kind of activity to continue, because they were used when people came to the Congress and when some previous Member of Congress said, who is for this, they said, oh, everybody is for this because these are the benefits. But those benefits haven't flowed exactly as they were represented, either to the Congress and/or to those communities and/or to the Native Americans, and we just cannot have some artificial technical barriers stand in the way of providing allocations to tribes. They have to have access to some of these same services and resources.

Thank you very much for your testimony. Obviously, this is ongoing, but I think, Mr. Secretary, your statement, as I said earlier, takes us a long way down the road to narrowing the issues. I think we will be moving forward on this issue of what I think we felt was an unacceptable length of contract. And as you have raised some of the other additional issues, I think there is some area for some agreement here and I appreciate that very much. Mr. Beard, thank you for your testimony.

Mr. WHITE. Thank you.

Mr. MILLER. Thank you.

PANEL CONSISTING OF BRUCE C. DRIVER, DIRECTOR AND SENIOR COUNSEL, ENERGY PROJECT, LAND AND WATER FUND OF THE ROCKIES, ON BEHALF OF THE LAND AND WATER FUND AND FOR THE ENVIRONMENTAL DEFENSE FUND (ROCKY MOUNTAIN OFFICE), GRAND CANYON TRUST, NATIONAL PARKS AND CONSERVATION ASSOCIATION, NATIONAL WILDLIFE FEDERATION, NATURAL RESOURCES DEFENSE COUNCIL AND THE SIERRA CLUB (GRAND CANYON/ARIZONA CHAPTER); PAUL LITTLE, DIRECTOR, OGLALA SIOUX RURAL WATER SUPPLY PROJECT ON BEHALF OF MNI SOSE INTER-TRIBAL WATER RIGHTS COALITION OF THE MISSOURI RIVER BASIN; JUDY KNIGHT-FRANK, CHAIRMAN, UTE MOUNTAIN UTE TRIBE; AND MICHAEL EPPERSON, FINANCIAL ANALYST, SAN FRANCISCO BAY AREA RAPID TRANSIT DISTRICT

Mr. MILLER. The next panel will be made up of Mr. Bruce Driver, who is the senior counsel, Land and Water Fund of the Rockies, Boulder, Colorado; and Mr. Paul Little, who is the director of the Oglala Sioux Rural Water Supply Project; and Ms. Judy Knight-Frank, who is the chairman of the Ute Mountain Tribe; and Mr. Michael Epperson, who is the financial analyst from the San Francisco Bay Area Rapid Transit District.

Welcome to the committee. I am sorry we have gone on a little bit longer than anticipated, but thank you for sticking with us.

An AUDIENCE MEMBER. Mr. Miller, could I make a point of clarification? We inherited you people, you didn't inherit us.

Mr. MILLER. I made that clarification. We inherited the responsibility back, was my point.

Mr. Driver, we will begin with you.

STATEMENT OF BRUCE C. DRIVER

Mr. DRIVER. Thank you very much, Mr. Chairman. My name is Bruce Driver. I am appearing today as the director and senior counsel to the Energy Project of the Land and Water Fund of the Rockies. The fund is a regional environmental legal center serving the Rocky Mountain intermontane and desert southwest region of the United States.

For about three and a half years, the LAW fund has been a very active participant in the public procedures that surround Western's attempts to deal with customer contract extensions and integrated resource planning, or IRP. On May 16 of this year, we filed comments on Western's draft environmental impact statement on the energy planning and management program. These comments were filed for ourselves, as well as for the Environmental Defense Fund, Grand Canyon trust, National Parks and Conservation Association, National Wildlife Federation, Natural Resources Defense Council, as well as the Sierra Club. I speak for those groups today as well as for the Land and Water Fund.

There are four principal contextual factors which we believe need to be considered in determining proper contract extension policies for Western. They are, one, impact on the environment from Western's operations; two, the large and relatively untapped energy efficiency as well as renewable electric generation resources that exist in the West; three, the very rapidly changing face of the utility industry that is a result of increasing competition therein; and, four, the presence of entities like the tribes other than Western's existing customers who seek access to the Federal hydro resource.

As to the environmental impacts of Western's operations, they fall into two basic categories: First, impacts on fish, wildlife, as well as recreational resources from operation of Federal dams to generate electricity; secondly, impacts on air, land, and water resources from the generation of the enormous amount of electricity Western purchases from regional utilities to firm its Federal hydro resource.

Impacts on fish, wildlife and recreational resources of the operation of the dams are quite well-known, and I won't spend too much time on them today, except to say that these impacts and the EIS and other procedures which these impacts have begun to trigger will definitely lead to some as-yet undetermined loss of the capacity value of the resource-rich Western markets.

The implication for Western is that its contract extension policies must remain sufficiently flexible to accommodate this loss.

A second type of environmental impact occasioned by Western's operation derives from the fact that Western purchases large quantities of power from neighboring utilities for redistribution to its customers. This power is used to firm the existing hydro resource. In fact, over the past five years, Western has spent between $200 and $300 million to purchase power, roughly 40 percent of its yearly expenses. A very large proportion of this power is from coal-fired generators. None at all is from renewable resources or from demand-side management.

The second factor that I want to talk about very briefly here today is that I want to make the point that in the West there remains an enormous and untapped reservoir of renewable resources as well as energy efficiency. In our view, Western can have a make-or-break impact on the development of those resources in certain parts of the West.

As part of DOE, Western should be proactively encouraging its customers and itself relying on these resources. However, to date, by and large, it has not done so at all.

The third factor to account for in trying to come up with a wise contract extension policy is the fact that there is rapidly increasing competition in the electric utility industry. In this environment of increasing competition, Western needs to maintain some flexibility and to avoid locking up with today's customers all or a very large fraction of its resource for a long time.

A final factor is, of course, the existence of the have-nots in the West. They may well be able to qualify, whether they are an electric utility or not, for some of the power that is available.

Western, simply from basic fairness perspectives, must not lock up Oregon, a very large proportion of its available resources, only with these existing customers. That just will be unfair.

Finally, to wind up, on the basis of these factors and contributions, we have certain basic recommendations to make.

First, before it extends any power sales contracts, Western should commit on a large-scale basis, in our view, the encouragement of the development of demand-side management and renewable resources in the region.

Secondly, it should integrate IRP principles into its own purchasing power and transmission programs. I am very pleased to have heard Secretary White tell us today that, indeed, he was going to be directing an effort to do that. I think he should be very highly commended for that decision.

Thirdly, it is high time for Western to issue and take public comments on its customers—on the customer IRP proposal. As you well know, Mr. Chairman, some statutory deadlines for that proposal to be out under section 114 of EPACT have passed. It is time for Western to make that proposal available for us to even comment on.

Next, for the environmental equity and other public policy reasons discussed, we do recommend that Western refrain from extending contracts for more than 10 to 15 years from the date on which the contracts are due to expire, and then, at this point, only for those contracts that expire in 2004 or before.

For similar reasons, we strongly recommend that Western refrain from committing anywhere near 100 percent of its resources now, especially only to existing customers. Instead, we recommend that Western consider committing now no more than 80 percent of resources that are available after environmental analysis will be complete, or 70 percent of today's existing resources.

Finally, if Western will make the commitment to vigorously promote and encourage DSM as well as renewable resource, we think that DOE should consider making a share of the revenues it now has available to it, to encourage DSM and renewables to Western for that purpose.

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Thank you very much. I would ask that my full statement be admitted into the record, and I would be glad to answer any questions that you may have.

The CHAIRMAN. Thank you.

[Prepared statement of Mr. Driver follows:]

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TESTIMONY OF BRUCE C. DRIVER

DIRECTOR AND SENIOR COUNSEL

OF THE ENERGY PROJECT OF THE

LAND AND WATER FUND OF THE ROCKIES

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

COMMITTEE ON NATURAL RESOURCES

U.S. HOUSE OF REPRESENTATIVES

ON

PROPOSALS TO ALLOCATE FEDERAL HYDROELECTRIC RESOURCES

JUNE 16, 1994

2260 Baseline Road • Suite 200 • Boulder, Colorado 80302 • (303) 444-1188 • FAX (303) 786-8054

I. INTRODUCTION AND SUMMARY

My name is Bruce Driver. I am appearing today as the Director of and Senior Counsel to the Energy Project of the Land and Water Fund of the Rockies. My business address is 2260 Baseline Road, Boulder, Colorado. I appreciate the opportunity to present to the Subcommittee our positions on Western Area Power Administration ("Western") proposals to allocate federal hydroelectric resources.

The Land and Water Fund of the Rockies ("LAW Fund") is a non-profit, regional environmental law center serving the Rocky Mountain and Desert Southwest states. The LAW Fund's Energy Project advocates the adoption of measures that would minimize the adverse environmental impacts associated with the provision of utility energy services. Primarily, we intervene in state public service commission proceedings in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming, for the purpose of encouraging utilities to invest in the energy-efficiency of their customers (through Demand-Side Management programs or "DSM") and renewable resources.

We have also been active participants in the public procedures surrounding Western's attempts to deal with customer contract extensions and integrated resource planning ("IRP") since 1991. It is mostly on the basis of this experience that I am testifying today, although the positions I express are informed by our activities at the state level.

On May 16 of this year we filed comments on Western's Draft Environmental Impact Statement ("DEIS") on the Energy Planning and Management Program ("EP&MP"). These comments, filed for ourselves as well as for the Environmental Defense Fund (Rocky Mountain Office), Grand Canyon Trust, National Parks and Conservation Association, National Wildlife Federation, Natural Resources Defense Council and the Sierra Club (Grand Canyon/Arizona Chapter), present our positions in detail. I have attached a copy of these comments to this testimony.

My testimony today is essentially a summary of our filed comments. Because a summary cannot do full justice to the complexity of the issues surrounding questions of contract extension, IRP and agency reform, I urge members of the Subcommittee to review the full comments.

Our positions on the principal issues before the Subcommittee today are:

1. Until Western issues a sound IRP rule for its customers, applies IRP principles to its own purchase power and transmission activities, and commits on a large scale to encourage the development of energy-efficiency and renewable resources in the region, it is premature for Western to extend contracts to its customers.

2. Considerations of equity, impact on the environment and sound public policy suggest that when Western is ready to extend contracts, as a result of having adopted the reforms referred to in paragraph 1, Western should refrain from extending contracts for more than 10-15 years and for more than 70%-80% of the resource.

II. CONTEXT AND IMPLICATIONS FOR CONTRACT EXTENSIONS

There are four principal contextual factors which should be considered in determining proper contract extension policies for Western. They are:

1. The impact on the environment from Western's operations;

2. The large and untapped energy-efficiency and renewable electric generation resources that exist in the West;

3. The rapidly changing face of the utility industry resulting from increasing competition; and

4. The presence of entities other than Western's existing customers who seek access to the federal hydroelectric resource.

In this section we discuss these factors and the implications they have for the establishment of sound contract extension policy.

A. ENVIRONMENTAL IMPACTS OF WESTERN OPERATIONS

The environmental impacts of Western's operations fall into two principal categories: (1) impacts on fish, wildlife and recreational resources from operation of federal dams to generate electricity and (2) impacts on air, land and water resources from the generation of the enormous amount of electricity Western purchases from regional utilities to firm[1] its hydro resource.

It is well known that operation of dams on the Colorado River have a significant and adverse impact on fish, wildlife and recreational resources, even while they have generated large amounts of inexpensive power over the years. Several processes are underway to analyze and mitigate these impacts:

1. The Bureau of Reclamation's EIS on the operation of the Glen Canyon Dam. The Bureau's 1993 Draft EIS identified a number of environmental problems associated with current

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[1] In this testimony I use "firm" and "firming" to refer to all actions Western takes to purchase and market non-Western resources for the purpose of meeting contract obligations to its customers.

operation of the dam. Reoperation of Glen Canyon Dam to address these problems under the terms of the Grand Canyon Protection Act may occasion the loss of 700 megawatts of peaking power.

2. The Colorado River endangered fish Recovery Implementation Program. Data already collected by the U.S. Fish and Wildlife Service indicate that recovery of endangered fish species in the river will not be accomplished without modification of flows controlled by federal dams on the Colorado and Green Rivers.

3. Western's EIS on its plans to market power from the Salt Lake Integrated Projects.

The operation of dams associated with the Central Valley Project also has significant, adverse impacts on fish and Western's current EIS on its CVP marketing plans is looking into these impacts. On the Missouri River the U.S. Army Corps of Engineers is reviewing its Master Manual for operating the dams on the river. While it is early in the process, the U.S. Fish and Wildlife Service, U.S. EPA and a number of environmental groups believe that current operation of the dams is having adverse impacts on fish and wildlife species.

The impacts on fish, wildlife and related resources occasioned by operation of dams providing power to the Western system and the EIS and other processes which these impacts have triggered will lead to some as-yet-undetermined loss of the capacity value of the resource which Western markets. The implication for Western is that its contract extension policies remain sufficiently flexible to accommodate this loss. In particular, Western must not allow the expectation to be created among its customers that they are assured of all or a very large share of the available resource on a long-term basis. Otherwise, it may become difficult to reoperate the dams to provide for reasonable environmental mitigation when that likely becomes appropriate.

A second type of environmental impact occasioned by Western's operations derives from the fact that Western purchases large quantities of power from neighboring utilities for redistribution to its customers. Over the past five years Western has spent between $200 and $300 million dollars annually on purchased power--roughly 40% of its yearly expenses. A substantial portion of this power is from coal-fired generators.

How did this happen? Primarily because Western believes it is authorized to buy and sell non-federal resources to its customers in order to firm the federal hydro resource which it is under contract to provide to its customers. We do not contend that Western's role in firming up the hydro resource is per se inappropriate, only that, because of Western's heavy reliance on coal-fired purchased power, Western's provision of this power to its customers raises environmental risks and problems. In this regard, the combustion of coal to generate electricity (using conventional technologies) is implicated in several significant environmental problems in the West: acid rain in fragile mountain environments, reduced regional visibility, "brown clouds" in western urban areas, adverse impacts on human health, damage from strip-mining and an increase in the emission of greenhouse gases.

We note that Western's 100% reliance on purchased power to firm the hydro resource is at variance with most utilities in the West. The practice among large investor-owned utilities in the states in which we operate and which need new resources is to try to meet one-third or more of load growth with DSM and to commit to acquire new solar and wind resources. Some of Western's own customers, most notably a number of municipal utilities in California, are making commitments to these resources far in excess of these levels. However, to our knowledge, Western has never acquired DSM or renewable resources as part of a package of resources used to firm the hydro resource.

The implication for contract extension policy is that, unless Western will join other utilities in the region and actively acquire DSM and renewable resources as part of its purchase power resource mix, it should withhold a share of its hydro resource as insurance against having to purchase power for firming purposes.

B. THE ENERGY-EFFICIENCY AND RENEWABLE RESOURCES AVAILABLE TO WESTERN

Over the past ten to fifteen years, a flood of new and inexpensive electricity-saving technologies have become commercially available. Electric utility industry and other studies have repeatedly shown that these technologies have the potential to cost-effectively save anywhere from 25%-40% of current electricity usage in the nation by the year 2000. Moreover, the environmental benefits of these technologies are impressive. For example, one high-efficiency light bulb can eliminate the need to burn over 1000 pounds of coal over its lifetime.

The West also has the nation's best solar, geothermal and wind resources. Indeed, utilities in the West could meet a substantial portion of the region's electricity needs with renewable resources were they able to capture but a small percentage of the gross renewable resource potential that exists in the region. Recent technological improvements have lowered the costs of renewable technologies. Thus, under a wide range of future fossil fuel price assumptions, windpower is cost-competitive in Colorado as is geothermal in Nevada and Utah. Solar is already cost-competitive in niche applications throughout the West and may, in solar-thermal grid-connected applications, compete with fossil fuel generation capacity early in the next century.

We note the reliance on both renewables and DSM by the President's Climate Change Action Plan to offset the build-up of greenhouse gases. DSM and renewables also have job, tax base and other economic benefits for the West. Indeed, these resources, as well as others, including natural gas and potentially coal if it can be burned cleanly, will play a key role in clean and sustainable economic development in the West over the coming decades. But for the promise of DSM and renewables to be fulfilled, Western will have to promote them, both for Western's use as well as by their customers. It is not an exaggeration to say that Western can have a "make or break" impact on the market penetration of DSM and renewables in certain parts of the West.

The implications for the EP&MP rulemaking, are, first, that Western should promptly develop and publish its customer IRP rules, already well behind statutory deadlines established in section 114 of the Energy Policy Act of 1992 ("EPACT"), and greatly step up and refocus its technical assistance to customers to help them acquire

DSM and renewables. Second, if IRP is good for its customers, it is also good for Western, especially to bring balance to its purchased power program and to guide its large scale transmission construction investments.[2] Third, unless Western integrates DSM and renewables into its purchase power program, its claim in the DEIS that long-term, high percentage allocations of its hydro resource provides environmental benefits is incorrect. In fact, the contrary is quite possible: Western's purchase power program could have the perverse effect of supplanting customer reliance on DSM and renewables.

C. INCREASING COMPETITION IN THE ELECTRIC UTILITY INDUSTRY

Another development which bears on the choice of contract extension policy is increasing competition in the electric utility industry. EPACT empowered the Federal Energy Regulatory Commission to order utilities and Western to open their transmission systems to power from other utilities and independent power producers. Changes in state regulation will likely complement and expand upon the federal legislation. There is much talk about the possible separation of the power generation function of the industry from transmission and distribution. In short, it is not at all clear that the utility industry serving our needs in 2005 will resemble

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[2] We note that IRP is standard practice for power suppliers at the state level in most states in which Western markets power. The core of IRP is equal balancing of demand- and supply-side options in a search (directed by the power supplier but with public input) for a mix of resources that would meet the demand for energy services at the least cost, including environmental costs, over the long-term. Appendix C to our formal comments includes a proposed rule that would have Western apply an abbreviated form of IRP to its power purchase and major transmission investment decisions.

the large vertically integrated companies we know now.

These developments will not leave Western's customers untouched. A few may find they do not want or need their allocation of Western power in ten years. Other potential preference customers may be created in the wake of the break-up of larger companies. In this environment Western needs to maintain flexibility and to avoid locking up with today's customers all or a very large fraction of its resource for a long time.

D. THE PRESENCE OF OTHER CUSTOMERS FOR THE WESTERN RESOURCE

Even in the absence of changes in the industry, there are other preference customers who today have no access to Western's resource but who seek it, such as tribes and municipal agencies. It strikes us that allocation of over 90% of the available resource to existing customers, as Western has proposed in the DEIS, is manifestly unfair to these "have-nots" because it will leave Western with insufficient power to market to them.

RECOMMENDATIONS

First, Western is not yet ready to extend contracts for the use of the hydro resource because it has not considered the foregoing risks, opportunities and uncertainties in the EP&MP DEIS. We recommend that, before Western extend any power sale contracts, it should:

1. Commit on a large scale to encourage the development of DSM and renewable resources in the region.
2. Integrate IRP principles into its own purchase power and transmission programs.

3. Issue and take public comments on a customer IRP proposal.

Second, for the environmental, equity and other public policy reasons discussed above, we recommend that Western refrain from extending contracts for more than 10-15 years and then only for those contracts that expire in 2004 or before. For similar reasons we recommend that Western refrain from committing anywhere near 100% of its resources now, especially to only existing customers. Instead, we recommend that Western consider committing now no more than 80% of resources available (after environmental analyses are complete) or 70% of today's existing resources.

Finally, if Western will make the commitment to vigorously promote and encourage DSM and renewable resources by (1) integrating them into its purchase power and transmission construction programs, (2) systematically using its extensive transmission system to bring renewables to market, (3) sponsoring additional renewable resource pilot programs with its customers, (4) developing and widely disseminating information about renewables throughout the region, (5) proposing customer IRP rules that offer maximum encouragement to its customers to acquire DSM and renewables, (6) expanding its DSM and technical assistance program and refocusing it on helping customers acquire DSM and (7) agreeing to give DSM and renewables serious and tangible consideration in the process of seeking replacements for the loss of peaking capacity at Glen Canyon, it would appear appropriate that DOE make a share of the monies it has available to encourage DSM and renewables to Western for this purpose.

Attachment

COMMENTS OF THE ENVIRONMENTAL ORGANIZATIONS ON WESTERN'S ENERGY PLANNING AND MANAGEMENT PROGRAM DRAFT EIS

May 16, 1994

COMMENTS OF THE ENVIRONMENTAL ORGANIZATIONS ON WESTERN'S ENERGY PLANNING AND MANAGEMENT PROGRAM DRAFT EIS

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COMMENTS OF THE ENVIRONMENTAL ORGANIZATIONS ON WESTERN'S ENERGY PLANNING AND MANAGEMENT PROGRAM DRAFT EIS

These are the comments of several environmental organizations with a long tradition of interest and involvement in western energy and water issues, namely, the Environmental Defense Fund (Rocky Mountain Office), Grand Canyon Trust, Land and Water Fund of the Rockies, National Parks and Conservation Association, National Wildlife Federation, Natural Resources Defense Council and the Sierra Club (Grand Canyon/Arizona Chapter). All told, these organizations have over two million American citizens as members. Further detail about these organizations is provided in Appendix A.

As a result of our review of the Draft EIS, we have concluded that certain practices of the Western Area Power Administration ("Western") are in need of fundamental reform. In short, the prospect of extending power sales contracts raises a host of closely-related issues that must be addressed before important decisions are made regarding the use of the federal hydroelectric resource which Western is charged with marketing. These issues include Western's acquisition of supplementary resources to meet the needs of its customers, its role in building new and using its existing transmission capacity, and its role in moving renewable resources to market and encouraging electricity use efficiency in this part of the country. In our view, Western must address these issues in conjunction with determining contract extension policy or risk making major errors which the region will regret for decades to come.

Thus, we strongly recommend that Western broaden the scope of its proposals beyond contract extensions and customer IRP to include a package of reforms, including better decisional processes for Western's power purchases and transmission investment and development of a strategic plan to assist its customers to acquire renewable resources and energy-efficiency resources. Because the Draft EP&MP EIS does not address these matters, we believe that it is incomplete and deficient.

In addition, and focusing on the content of the EIS, we believe that the Draft EIS alternatives providing large percentage allocations under long-term contracts will limit the flexibility with which Western can respond to the environmental and other changes that are sweeping the electric utility industry. Moreover, these contract extension alternatives do not provide the planning stability which Western's customers say they need.

More specifically, Western's Draft EIS on the Energy Planning and Management Program ("EP&MP") has the following problems:

* The alternatives containing long-term contract extensions with large percentage allocations will greatly reduce Western's flexibility to respond to changing environmental, competitive, and other circumstances;

* Alternatives that might provide greater flexibility and more planning stability were not examined;

* The Draft EIS does not provide the detailed IRP regulations, thereby making it impossible to evaluate this component of Western's proposal;

* The Draft EIS and the EP&MP do not consider proposals to reform Western's inadequate purchase power and transmission investment practices;

* The Draft EIS and the EP&MP do not provide sufficient incentives to encourage the customer utilities to invest in energy efficiency and renewable resources;

* In addition to having at least one significant analytical flaw, the Draft EIS fails to fully explain the relationship of the EP&MP EIS process to other environmental processes in which Western is involved.

Given these realities, we recommend that Western create a package of reforms as part of the EP&MP rulemaking process -- including smaller and shorter contract extensions, the establishment of clear-cut criteria and processes for Western's internal purchase power and other decisions, meaningful IRP requirements for Western's customers, and incentives that encourage customer utilities to promote energy efficiency and renewables. We believe that these reforms will provide Western and its customers with greater flexibility in responding to changing circumstances in a manner that is both economically and environmentally sustainable.

These comments review the environmental and other changes that are occurring in the electric utility industry, critique the role EP&MP will likely play in helping Western and its customers adapt to these changes, and present our recommendations for improving upon Western's EP&MP proposals.

I. The Broader Context Surrounding Western's Operations

Western's EP&MP will have a number of long-term implications. For example, a 25-year extension for contracts that expire in the year 2004 will largely determine allocations of the federal resource until the year 2030. To evaluate the appropriateness of such a long-term extension policy, it becomes necessary to understand the environmental, economic, and technological forces that are likely to shape the electric utility industry and directly affect Western and its customers during this time period.

One of the most important forces that has already shaped utility behavior involves the increasing attention being paid to environmental issues. Throughout the western United States, there is a growing realization that the generation and transmission of electricity is the source of many of the region's most intractable environmental problems.[1]

In this regard, there are a number of ongoing environmental processes that could have a significant effect on the operation of Western and its customers. The environmental process likely

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[1] These problems include, among others, acid depositions in fragile mountain environments, reduced visibility due to regional haze, the damming of free-flowing rivers, "brown clouds" in urban areas, adverse human health impacts, global warming, strip mining, nuclear waste disposal, and the destruction of valuable lands by transmission rights of way.

to have the greatest near-term impact on Western is the Bureau of Reclamation's EIS process for Glen Canyon Dam. The Bureau's December 1993 Draft EIS identified a number of potential environmental problems associated with dam operations involving: sediment transport; fish life cycles, habitat, and spawning; vegetation in the Colorado River corridor; endangered species issues; wildlife habitat; and cultural and recreational values. To resolve these concerns, it appears likely that the Bureau will have to substantially reduce the marketable peaking capacity of Glen Canyon dam. Moreover, even when the Bureau's EIS process is complete, an adaptive management component will likely produce further changes in dam operations over time.

Other environmental processes are also ongoing. For example, the U.S. Fish and Wildlife Service has initiated a "Recovery Implementation Program" for endangered fish species in the Upper Colorado River Basin. Data already collected by the Fish and Wildlife Service makes it clear that recovery of the Colorado endangered fishes will not be accomplished without modifying flows that are controlled by the federal dams on the Green and Upper Colorado Rivers. Such modifications will also likely affect Western's marketable resource.

Similarly, the U.S. Army Corps of Engineers has recently undertaken a formal review of its "Master Manual" for operating the dams on the Missouri River. The Fish and Wildlife Service, the U.S. Environmental Protection Agency, and a number of environmental groups believe that the Corps' operation of the dams principally to support flood control, navigation, and hydropower have had adverse effects on wetlands, fish and wildlife habitat, and native species. Although this process is still in an early phase, the final resolution of these issues is very likely to affect dam operations and electricity generation on the Missouri River.

Like the scientists involved in habitat restoration issues in the Glen Canyon dam EIS process, those working on fish recovery in the upper Colorado and the Missouri River basins have strongly urged the use of adaptive management methods. Appendix B, attached to these comments, provides further detail about the endangered species problems on both the Colorado and Missouri Rivers as an example of the relationship between environmental problems, dam operations, and Western's marketable resource.

Several other EIS processes could also influence the operation of the federal hydroelectric resources. Western is currently conducting an EIS on its marketing plans for power from the Salt Lake City Area Integrated projects. Western is also conducting an EIS for its Central Valley Project marketing plans. Among other impacts, this EIS will examine alternatives for adjusting reservoir temperatures to protect salmon.

In addition to these environmental processes that directly affect dam operations, outcomes in other forums may influence Western's thermal and purchase power resources. For example, SO_2 emissions may be regulated as a result of the work of the Grand Canyon Visibility Transport Commission, charged with making recommendations to the U.S. EPA as to what steps should be taken to reduce regional visibility degradation. Pressure to reduce CO_2 emissions will also likely increase. The President's Climate Action Plan, relying on voluntary actions, is one source of such pressure.

At the same time that greater environmental awareness will reduce Western's marketable resource, there is now a wide range of new environmentally sound technologies available for meeting the demand for energy services. For example, over the past ten to fifteen years a flood of powerful electricity-saving devices has become commercially available. Experts estimate that these technologies have the potential to cost-effectively save anywhere from 25 to 40 percent of current electricity usage in the West by the year 2000. Moreover, the environmental benefits associated with these technologies can be enormous, as one high efficiency light bulb can eliminate the need to burn over 1000 pounds of coal over its lifetime.

The western United States also has an enormous renewable resource potential. Wind, solar, and geothermal resources are all abundantly available in this part of the country. Indeed, if utilities were able to capture just a small percentage of the available wind or solar potential, they could meet a substantial portion of the region's electric needs. Moreover, recent technological improvements have lowered the costs of renewables making them economically competitive under a wide range of circumstances, particularly since these resources can help utilities diversify fuel price and environmental risks. Indeed, in a number of forums the U.S. Department of Energy (of which, of course, Western is a part) has recently stated its intent to greatly expand its commitment to renewable resources.

Finally, the role of Western in meeting its current customers' needs may be greatly influenced by the competitive changes that are occurring in the electric utility industry. As an example of these changes, the Energy Policy Act of 1992 empowered the Federal Energy Regulatory Commission to order utilities like Western and its customers to wheel power for other utilities. Changes in state law may complement and expand upon the federal legislation. Given this changing environment, substantial uncertainty exists in regard to the future shape of the utility industry.

II. Western's EP&MP in a Changing Industry

Western's EP&MP takes only the most tentative of steps in trying to manage and respond to the opportunities, risks, and uncertainties discussed above. Moreover, the EP&MP tends to perpetuate ongoing problems in regard to the internal decision making processes of both Western and its customers by failing to reform these processes.

A. Long-term, System-wide Contract Extensions at Large Percentage Allocations

Western's Draft EIS on the EP&MP has two separate components, one involving power marketing and the other involving energy planning for the customer utilities. This section describes the power marketing alternatives. The subsequent one discusses the planning component.

1. *Understanding Western's Power Marketing Proposals*

In the Draft EIS Western presents twelve different power marketing alternatives. Although there is some uncertainty, it is possible that these alternatives will apply generically across Western's entire system.[2] Nine of the twelve alternatives in Western's EP&MP Draft EIS (alternatives 2 through 10) provide contract extensions of between 90 and 100 percent of the available resource for between 10 and 35 years. Under these alternatives, Western would determine as part of this rulemaking process the exact percentage allocation and the specific length of the contract extension.[3]

Apparently, the available resource that is to be allocated at some fixed percentage will not be defined as a result of this contract extension process. Instead, the available resource will depend on the outcome of future adjustments that will be made as a result of changes in hydrology or river operation. Thus, the future available resource may be substantially different than existing allocations, as Western will adjust the available resource depending on the results of all the environmental processes described in the prior section (as well as any new ones).

Although Western examined nine alternatives, Western did not consider percentage allocations lower than 90 percent. Also, Western did not consider allocations based on a substantially lower percentage of the existing resource. Thus, Western has ignored options which may prove to be more attractive.

In any case, we have a number of problems with Western's nine proposed alternatives.

2. *Impacts on Western's Flexibility*

First, the contract extensions proposed in these alternatives (at 90-100% of the available resource) will reduce Western's flexibility to respond to changing environmental and other circumstances. This approach may limit Western's flexibility because generic extension alternatives will likely create unrealistic expectations among Western's customers regarding the size of the future resource. Notwithstanding that Western's customers should be on notice that the size of the resource depends on future conditions, we believe it highly likely that the customers will expect that they are entitled to a very high share of today's resource. Given these expectations, it will likely be far more difficult for the operators of the federal hydroelectric resources to modify dam operations in response to changing environmental needs in ways that reduce the resource. Thus, the expectations created by implementing any of these nine alternatives will likely constrain the outcomes of the ongoing environmental processes discussed above.

An example can help to illustrate this point. Suppose that as a result of this EP&MP process Western allocated a large percentage of the Pick-Sloan eastern division power under long-term contracts to existing customers. Based on these contracts, we believe that most customer utilities would assume for resource planning purposes that they were contractually entitled to continue to

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[2] The Draft EIS states that the power marketing component of the EP&MP will definitely apply to customers of the Loveland Area and Eastern Division of Pick Sloan projects. There is some uncertainty as to whether this process applies to the Central Valley, Parker-Davis, and Salt Lake City Area projects. See Western Draft EIS, at p. 14.

[3] Under these alternatives, contracts would be executed sometime during the next year or two, either when customer utilities submitted their IRPs or received approval for their IRPs.

receive most of their existing allocations.

Once contracts have been signed and resource planning decisions have been made, these Pick-Sloan customers will have an enormous vested interest in protecting those allocations. As a result, there is the potential for a bitter dispute over any proposals to address the environmental problems on the Missouri River that might reduce the available resource. Thus, from our perspective it is premature and counter-productive for Western to commit to large percentage allocations while there is still substantial uncertainty surrounding the outcome of the ongoing environmental processes. Instead, we believe it is better public policy to resolve the key environmental uncertainties before fully or nearly fully allocating the available federal resource.

3. *Lack of Resource Stability*

A second problem with Western's proposed alternatives involves a lack of resource stability. As discussed above, the resource actually available to Western's customers will depend on the outcome of a future process. As a result, the contract extensions produced by the EP&MP project are subject to considerable future uncertainty. This EP&MP approach thus defeats the primary goal of the EP&MP process: providing resource stability to enable Western's customers to engage in meaningful planning.[4] If the available resource is subject to large changes as a result of future processes, then we do not see how this EP&MP approach provides planning stability.

This problem can be more clearly seen by examining the resource planning problem of a utility that purchases large amounts of power from the Colorado River Storage Project ("CRSP"). Suppose the EP&MP program is implemented immediately such that this customer is guaranteed access to 95% of the future available resource. Nevertheless, the future available resource will not be known for years, depending on the outcome of three inter-related environmental processes (the Bureau's EIS at Glen Canyon, Western's Salt Lake City marketing EIS, and the Fish and Wildlife Service's endangered species analysis). As a result, the EP&MP process by itself provides practically no resource certainty for this customer.[5]

4. *Equity, Competitive, and Other Concerns*

The third problem with Western's generic contract extension alternatives is that they are unfair, as they essentially lock in current allocations of preference power. Indeed, the one uncertainty that is removed in regard to the determination of the future available resource is that new preference customers will not have access to these allocations. As a result of this lock in, potentially deserving new customers -- such as Indian Tribes or non-profit municipal agencies -- are foreclosed

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[4] See, e.g., Draft EIS, at p. 3 ("Quality utility planning is enhanced when a customer's power resources are stable and reliable."); See also Draft EIS, at p. 15.

[5] Our experience with Western's customers confirms this expectation. For example, Tri-State Generation and Transmission Assoc. is seeking to acquire new resources, in part, to make up for expected resource losses at Glen Canyon. The existence of the EP&MP provides no additional resource stability that would in any way alter Tri-State's plans.

from receiving allocations.[6]

Fourth, long-term contractual obligations at close to full allocation seems inconsistent with the competitive changes that are occurring in the electric utility industry. Smaller and shorter allocations would likely provide Western with greater flexibility to respond to whatever new competitive conditions might arise in the future.

Finally, over the past four or five years Western has had to purchase enormous amounts of power from neighboring utilities to meet its contractual obligations. As discussed in Section II.C.1 below, we believe that these purchases have substantial economic and environmental implications. Despite these implications, however, Western's EP&MP does not fully consider the relationship between large percentage contract allocations and Western's need to continue to purchase power.[7]

B. Customer IRP Requirements

The second component of the EP&MP involves an Integrated Resource Planning ("IRP") requirement for Western's customers. This requirement extends across all of the alternatives analyzed in the Draft EIS (except the No Action alternative). There is a question presented, however, about whether there should be an exemption for small utilities.

We applaud Western's decision to encourage its customers to engage in IRP processes consistent with the requirements in the Energy Policy Act of 1992 ("EPAct"). We also believe that Western has worked very hard to help its customers understand and learn about the benefits of IRP in planning for an uncertain future.[8] This effort has been particularly important since, as a general rule, many of Western's customers are substantially behind the leading investor-owned utilities in terms of IRP and promoting energy efficiency.

Nevertheless, the key details of Western's customer IRP program have (inexplicably) not

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[6] Western's allocations of preference power carries an enormous economic privilege. For example, Western's current contracts generated $740 million in revenues in 1993 alone. In this region, access to firm power of this type is probably worth 2-3 times this amount. Thus, the EP&MP contract extensions would accord an enormous privilege of maybe $1 billion per annum -- or, over 25 years, about $10 billion in present value terms. It is critical that this privilege not be extended without care and without some access to the process for those who have not yet been able to share in the federal resource to date.

[7] We do not take a position here about whether it is appropriate for Western to purchase this much power. If Western's purchase power practices were improved, these purchases may be appropriate. Nevertheless, we believe that this issue should be included as part of the EP&MP Draft EIS analysis.

[8] We have reviewed the materials that Western plans to provide to its customers to help them develop meaningful IRPs. In general, we are impressed with the comprehensive and thoughtful nature of these materials.

been made available. This failure is especially surprising since statutory deadlines for program implementation have long since passed. Moreover, based on extensive experience in developing and implementing IRP processes for investor-owned utilities, we believe that the detailed language of the regulations implementing the IRP program will be key. As a result, we are unable to take a position either in support of or in opposition to Western's IRP proposal until the detailed language is available.[9] Indeed, the absence of the customer IRP proposal makes it impossible for us to know if the claims made in the Draft EIS regarding the effect of the IRP on Western's customers have merit.

C. Western's Internal Practices

As discussed above, Western is requiring its customers to implement IRP and consider energy efficiency and renewable resources to help them manage risks in an uncertain and rapidly changing planning environment. This is good public policy. Nevertheless, if IRP is desirable and appropriate for Western's customers, why shouldn't Western adopt similar processes to govern its own internal decision making? On this point, Western's EP&MP is largely silent.

1. *Purchase Power and Transmission Investments*

The problems with Western's internal decision making can be seen especially clearly in the purchase power area. Western currently purchases enormous amounts of power from neighboring utilities.[10] Moreover, this problem is likely to become worse in the future as restrictions at Glen Canyon Dam and other federal hydroelectric resources further reduce the available capacity.

Western's heavy reliance on purchased power (under contracts as long as five years) creates both economic and environmental risks. Since much of the energy purchased by Western is coal-fired,[11] Western is causing substantial adverse air quality and other environmental impacts by paying other utilities to burn coal to meet Western's needs. Indeed, Western has become one of the larger coal-based utilities in the region as a result of its purchase power practices. Under these circumstances, Western should begin analyzing its effect on regional emissions of pollutants and developing mitigation strategies.

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[9] Similarly, although we tend to be supportive of the small customer exemption, it is impossible to develop a final position until Western's detailed proposal is available.

[10] In 1993, Western purchased over 12,000 GWh of power from neighboring utilities. These purchases provided roughly a third of Western's resource base -- about 1300 MWa on average. This level of purchased power has remained roughly consistent over the last four to five years. Based on the last few years of data, this problem appears to be particularly acute for the Central Valley Project and the Eastern Division of Pick-Sloan.

[11] For example, in 1993 Western spent over $70 million to purchase 1,400 GWh from PacifiCorp and over 1,450 GWh from Basin Electric. Both of these utilities are predominantly coal based.

Western's purchase power program may also have adverse economic impacts. Over the past five years, Western has spent between $200 to $300 million annually on purchased power -- roughly 40% of Western's yearly expenses. Because of these purchase power expenses, Western's ability to meet its repayment obligations in a timely fashion may have been compromised. Moreover, over time these purchases could become substantially more expensive due to increased environmental regulation of SO2 and CO2. Given this potential risk, Western should do everything in its power to ensure that the risks of future, more stringent environmental regulations are borne by the selling utilities.[12]

Given these concerns with purchase power, Western's current decision making in this area is inadequate. First, Western's decisions regarding purchase power are not subject to a clear least - cost standard. As a result, Western is likely purchasing power that is substantially more expensive than available alternatives. Since Western is under no obligation to select the least-cost means of accomplishing its purchase power objectives, Western's decisions can become political with no clear decision making criteria available.[13]

A second problem arises because Western's decision making criteria do not require a comprehensive review of all the alternatives available. For example, in its purchase power program Western has been spending at least $200 million annually to acquire new resources. Of this acquisition, Western has not invested in (or considered) energy efficiency or renewable resources even though these options may be substantially cheaper. In contrast, if a large investor-owned utility was spending $200 million a year to acquire new resources, we would expect that at least a third would be devoted to energy efficiency and at least ten percent to renewables. Western, however, has chosen to ignore these alternatives. Given national policies to encourage energy efficiency and renewables (as reflected, for example, in the President's Climate Change Action Plan), this is not acceptable, especially since Western is a federal agency.

Western has also failed to explore the possibility of coordinating environmental mitigation strategies with the Bonneville Power Administration. Since both agencies sell power from systems with large storage facilities, there may be win-win opportunities through increased coordination. These coordination activities could also reduce the need to incur large purchase power expenses.

Western's decisions to invest in new transmission lines are subject to similar criticisms. For example, in evaluating the Navajo Transmission Project – a $120 million transmission investment that would facilitate power transfers between the Four Corners region and southern Nevada -- Western examined a number of alternative pathways for the proposed line consistent with its EIS requirements. However, at no time was Western required to show that this line was a least-cost

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[12] See generally, Cavanagh, et. al., Utilities and CO2 Emissions: Who Bears the Risks of Future Regulation?, The Electricity Journal, March 1993, at p. 64.

[13] This problem is aggravated in the Central Valley Project where it is our understanding that Western is currently bundling purchase power costs into overall project rates. As a result, customer utilities do not have an opportunity to avoid Western's expensive power purchases. It is our understanding that a number of the customer utilities share these concerns.

alternative (as compared to building new resources or investing in greater energy efficiency) for meeting the regional demand for energy services. Nor was Western required to consider this line's impact on regional utility resource development.

2. *Promoting Energy Efficiency and Renewables*

We believe that Western could do a much better job promoting energy efficiency and renewable resources among its customers. Indeed, more rapid acquisition of these resources would help to mitigate some of the adverse impacts associated with Western's purchase power practices. Although Western does have a technical assistance program (which we support), this program is tiny compared to Western's large resource acquisition and purchase power program.[14]

In the energy efficiency area Western could do much to expand its efforts to focus on helping its customers avoid the need to build expensive and environmentally damaging new plants. Currently, Western's focus has been on providing technical assistance, not on helping its customers to acquire the efficiency resource. Western's role in promoting energy efficiency is particularly important since access to cheap federal power reduces the incentives of both utilities and retail customers to promote efficiency.

Similarly, Western could be more pro-active in encouraging the development of renewable resources. For example, Western has a large transmission grid that can be instrumental in moving remote renewables to load centers. By pro-actively identifying and encouraging individual opportunities, Western could potentially do much to facilitate the development of these resources. Yet we are aware of no strategic effort by Western to identify how it might be useful in moving renewables to market. In this regard, a renewable resource acquisition target for Western would likely be appropriate. Western could also expand upon its existing efforts (which we support) to provide technical assistance to utilities investigating renewable resources.

D. Energy Efficiency and Renewable Resource Incentives for the Customer Utilities

Western has not created an incentive to encourage its customer utilities to promote energy efficiency and renewable resources. We would urge Western to establish such an incentive mechanism as part of the EP&MP process. One way to create such an incentive is to withhold a small portion of Western's resource and to offer it as a reward for superior IRP, energy efficiency, or renewables activities. However, we acknowledge that there are administrative problems associated with allocating power based on energy efficiency and renewable resource achievements.[15] To

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[14] Western's technical assistance program has been capped at roughly $5 million per year. In contrast, Western's purchase power activities range from $200 to $300 million per year with very little review of the overall economics of these purchases.

[15] See, e.g., Draft EIS, at p. 22. Western also argues that it would be difficult to ensure that all the incentive did not go entirely to the large utilities. However, this is not a difficult problem to deal with as Western could easily decide beforehand to divide the available incentive so that an equitable share was guaranteed to small utilities.

address this problem, we proposed (almost three years ago) in earlier comments that Western create a pool of assistance dollars that could help supplement and support customer utility investments in energy efficiency and renewables.[16] This pool could provide a strong and flexible incentive for Western's customers to invest in these environmentally sound resources. Finally, Western should also analyze the potential role alternative rate structures could play in encouraging increased energy efficiency.

E. Analytical Problems with the Draft EIS

In the draft EIS Western analyzes the environmental impacts associated with its twelve alternatives. Western generally concludes that the greater percentage allocations produce less adverse environmental impacts.[17] In reaching this conclusion, however, Western has essentially assumed that it purchases no power. As a result, Western's analysis assumes that additional percentage allocations enable customers to use federal hydropower to displace fossil fuel alternatives that are more damaging.

This assumption is not correct. As discussed above, Western typically purchases almost one-third of its energy from neighboring utilities. Moreover, as we have said, a significant portion of this power comes from existing coal-fired power plants. As a result, larger percentage contract allocations may have the perverse result of having coal-fired power purchased by Western displace customer investments in energy efficiency and renewables. Thus, Western's environmental analysis needs to be significantly broadened to examine Western's purchase power practices. In the Final EIS, we urge Western to correct this flaw by fully examining the role purchased power plays under a variety of contract extension scenarios.

The substantive shortcomings of the present draft EIS are compounded by the fact that Western is pursuing several important power marketing analyses simultaneously. For example, as discussed above, Western is currently soliciting public comment on a draft EIS for the Salt Lake City Integrated Projects, and is a cooperating agency in production of the draft EIS on Glen Canyon dam operations. Despite these and other environmental processes, however, the EP&MP draft EIS makes no effort to analyze the relationships between and among these planning processes. It is thus unclear how decisions reached pursuant to this draft EIS will be affected, if at all, by decisions made under the other processes. Even a careful reader of the present draft EIS cannot determine whether Western is developing its power marketing policies in a piecemeal or in a coordinated manner. The resulting confusion creates suspicion of, rather than confidence in, Western's administration and adherence to the public interest.

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[16] See LAW Fund Comments on Western's Proposed EP&MP, filed July 31, 1991, at p. 15. Similar suggestions also were contained in later comments sent to Western. We believe that this pool should be equal to about 2% of Western's gross revenues or $10-15 million per year.

[17] See, e.g., Western's Draft EIS, at p. 81 ("For most environmental impacts identified in the analysis, benefits to the environment were predicted when assured, relatively high percentages of Western resources were extended.")

We believe that Western must revise the EP&MP EIS to analyze and disclose fully its relationship to all other power marketing planning efforts now underway, particularly those cited above. Western must explain whether and how different processes and policies will apply to different power marketing contracts and, if such differences do exist, why that is so, both as a matter of law and policy. Without such explanations, it appears that Western has made arbitrary choices to apply different power marketing policies to different customers. Without these revisions, the EP&MP EIS is flawed.

III. Recommendations

The Environmental Organizations urge Western and the Department of Energy to adopt an option that is not explicitly offered. Under this new option, we would urge Western to create a package of EP&MP reforms that would be included in the final rule. This package would extend the contracts and, at the same time, systematically address the concerns discussed above such that Western could more flexibly respond to changing environmental and other circumstances.

A. Broader Reforms

These comments have identified a number of problems with the way Western currently operates. Despite these problems, however, there is nothing in the EP&MP that would address them. Since Western has taken a long-term, system-wide approach to contract extensions, we believe the EP&MP is the appropriate forum for addressing these other issues.

Under our alternative EP&MP proposal, Western would commit now (as part of this rulemaking process) to specific standards that would govern its own transmission investment and purchase power decisions. These standards would set forth a specific least-cost criterion, would require a consideration of all alternatives (including energy efficiency and renewable resources), and would require Western to adopt a regional perspective for its environmental and other analyses. Draft proposed language implementing this feature of our proposal is attached to these comments as Appendix C.

As part of this reform, Western should also begin to acquire energy efficiency and renewable resources now as a practical alternative to its enormous purchase power expenses. That is, if Western continues to rely heavily on purchased power, then it must diversify its resource acquisition portfolio such that energy efficiency and renewables are included. Similarly, Western should also commit to creating a pool of assistance dollars that would encourage (through incentives) its customers to invest in energy efficiency and renewable resources.

To help link these diverse activities together into a coherent effort, we strongly suggest that Western develop a strategic energy efficiency and renewable resource plan. The plan could be developed with the input of Western customers, other offices in DOE, the National Renewable Energy Laboratory, western state energy offices, and the environmental organizations sponsoring these comments. Development of such a plan would help to give us the confidence that Western is taking its role in this area seriously.

Our final position on the exact contract extension length and percentage allocation depends on Western's willingness to consider the reforms that we propose, especially those relating to reform of Western's purchase power and transmission practices.

B. Contract Extensions

Given the problems with the nine alternatives included in Western's Draft EIS, we would urge Western to consider an additional alternative. Under this alternative, Western would extend its contracts for no more than ten years at a lower percentage, say 70% of existing allocations.

This more limited commitment, by creating a sizable resource pool, will provide Western with flexibility in regard to how it responds to changing environmental constraints. It will also ensure that the expectations of Western's customers do not become completely inconsistent with the size of the likely available future resource. Thus, this approach should ensure that the ongoing environmental processes can reach a fair outcome before the federal resource is fully allocated.

Moreover, this smaller allocation should ensure that some amount of power will likely remain available for deserving new preference customers thereby lessening some of the equity concerns described above. It also provides Western with the flexibility to explore the extent to which its current contractual commitments are requiring enormous purchase power expenses. By not committing the entire resource, Western still has the flexibility to reduce its percentage allocations to levels that limit purchase power to whatever levels are deemed appropriate.

Perhaps even more importantly, this approach provides Western's customers with resource stability now. Although the overall size of the Western resource committed now may be diminished, Western's customers can count on receiving a specific amount of power. As a result, the size of the available resource will not be left undecided until some future process. Western's customers would know now that a guaranteed 70% of the existing allocation would be provided.

We reiterate, however, that our proposal is that Western consider this alternative as we are not certain that it is preferable to other alternatives, only that it should be analyzed.

C. Customer IRP

Western needs to make available to the public (as soon as possible) the detailed regulations that implement IRP for the customer utilities. These regulations should be consistent with the statutory requirements in the recent federal legislation so as to implement a meaningful IRP process for the customer utilities. Despite statutory deadlines that have long since passed for implementing these provisions, Western has not even made draft language available to the public. Until such language is available, we take no position on Western's IRP requirement.

D. Alternative 11 or 12

If Western will not consider our proposal on contract extensions as outlined above, then we would support either Alternative 11 or 12. Under these alternatives, the customer IRP requirement would proceed separately and the contract extensions would occur on a project-specific basis. This would produce the economic and environmental benefits of customer IRP without needlessly constraining the ongoing environmental processes. This approach also ensures that some power is available for new preference customers.

IV. Conclusion

We believe that Western should determine its contract-extension policies in the context of reforms of purchase power, transmission and other activities triggered by Western's obligations to its customers. We urge Western to revise and amend its Draft EIS to address these issues. As part of this package, Western should also commit to more aggressively acquire and promote energy efficiency and renewable resources consistent with an overall strategic plan. We also urge Western to maximize the flexibility with which it approaches the increasingly unpredictable future in which it and its customers will operate by considering our contract extension option.

APPENDIX A

A Brief Description of the Environmental Organizations

The Environmental Defense Fund (Rocky Mountain Office) is a non-profit organization which links science, economics, and law to create innovative, economically viable solutions to today's environmental problems. EDF has more than 250,000 members nationwide.

The Grand Canyon Trust is dedicated to the conservation of the natural and cultural resources on the Colorado Plateau. The Trust advocates an ecologically responsible and sustainable balance between resource use and preservation, along with the protection of areas of beauty and solitude.

The Land and Water Fund of the Rockies (LAW Fund) is a regional environmental law center serving the Rocky Mountain states. The LAW Fund's Energy Project was created to promote energy efficiency and renewable resources in the Rocky Mountain and Desert Southwest regions through selective interventions in regulatory and administrative proceedings.

The National Parks and Conservation Association (NPCA) is America's only national, non-profit citizen organization dedicated to promoting the protection, enhancement, and public understanding of the national park system. Founded in 1919, NPCA has a national membership of more than 300,000.

The National Wildlife Federation (NWF), with 5.8 million members and supporters, is the nation's largest conservation education organization. NWF's primary objective is to promote the wise use of natural resources through education programs, publications, research activities, cooperation with legislators, government agencies and private groups.

The Natural Resources Defense Council has combined law, science and grass roots strength in defense of the environment since 1970. Over 170,000 members support NRDC's work.

The Sierra Club (Grand Canyon/Arizona Chapter) has a broad interest in a number of environmental issues, but has focused mainly on public lands, range management, and forestry issues.

APPENDIX B

A DETAILED DESCRIPTION OF ENVIRONMENTAL PROBLEMS ON THE COLORADO AND MISSOURI RIVERS

The Colorado River

Historically, the Colorado squawfish, bonytail chub, humpback chub, and razorback sucker were the dominant fishes in the mainstream habitats of the Colorado River system. They were widely distributed and common-to-abundant in the mainstem and all the major tributary basins of the drainage. However, all four species are now threatened with extinction due to the combined effects of: 1) habitat loss; 2) regulation of natural flows, temperature and sediment regimes; 3) proliferation of introduced competitors and predators; and 4) other man-induced disturbances that, in one instance in the Green River, included active efforts to eliminate them in favor of introduced game species.

To reverse the trend, an ambitious program with the formal title of Recovery Implementation Program for Endangered Fish Species in the Upper Colorado River Basin (RIP) has been created under the direction of the U.S. Fish and Wildlife Service. One of its central features is the establishment of habitat needs of the fish in an open scientific forum as the basis for operating federal reservoirs and for purchasing or acquiring, by other means, water rights under existing state systems to meet the agreed upon needs. A fundamental element of habitat need is the reestablishment of more natural flows[1], flows that are governed primarily by releases from federal hydropower facilities from which Western markets power.

Past operations of federal dams have eliminated the spring peak which, in turn, have modified the river's geomorphology and reduced the connectivity of the river and its flood plain. Daily and hourly fluctuations have had an effect too, decreasing the productivity and food web stability in the shallow near shore portions of the river's cross section. The aggregated impact of these habitat alterations has been very harmful to the fish.

Flow needs of the fish are influenced by many factors including time of year and life history stage for each species and changing the present pattern of flows at crucial times in the life-cycle of each species is central to the success of the recovery effort. Reproductive activities of the squawfish, razorback sucker, and humpback chub are associated with spring and early summer hydrologic events. Substantial deviations from the "natural hydrograph" affect spawning migrations and recruitment of the squawfish, humpback chub, and razorback.

Gradually declining summer flows and maintenance of low, stable flows in the late summer and autumn are presumed to be necessary for growth and survival of the young of all the rare

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[1] Stanford, Jack A., "Instream Flows to Assist the Recovery of Endangered Fishes of the Upper Colorado River System: Review and Synthesis of Ecological Information, Issues, Methods and Rationale (Second Draft Report)," prepared for the Instream Flow Subcommittee of the Fish Recovery Program and for the U.S. Fish and Wildlife Service, June 28, 1993.

species. Abrupt fluctuations in surface water elevation in late summer to spring are believed to strand squawfish and other backwater species and unnaturally high summer and early autumn flows (resulting from reservoir operations) are correlated with recruitment failure of squawfish.

A case in point is the Green River, controlled since 1963 by Flaming Gorge Dam. Notwithstanding the magnitude of the changes that the Green has experienced in the past 30 years, the Fish and Wildlife Service has concluded that the Green and Yampa rivers, when taken together, "constitute the most important riverine system for maintenance and recovery of rare Colorado River fishes."[2] The spring and early summer peak in the existing Green River hydrograph below the confluence with the Yampa in Dinosaur National Monument is maintained by the Yampa and, according to the Service, the Green River basin continues to support the "largest numbers of Colorado squawfish and razorback suckers in native riverine habitats."[3] In addition, the Yampa contains a self-sustaining humpback chub population. Both the squawfish and the razorback sucker also depend on habitats in the Yampa for fulfillment of various life history requirements. In fact, the Service has concluded that the two rivers (and their biologic and hydrologic interrelationships) are so important that they "must be considered as a single ecosystem when determining the needs of the indigenous rare fishes."[4]

In July 1991, the Fish and Wildlife Service published "Habitat Use and Streamflow Needs of Rare and Endangered Fishes in the Green River, Utah," in which it concluded that "current operations of Flaming Gorge do not provide desirable flow and temperature conditions for downstream native fish populations."[5] In the report, the Service went on to make flow recommendations for the spring, summer, winter, and fall.

These flow recommendations, though they do not actually replicate nature, constitute an important initiative -- the proposed use of a federal facility designed for hydropower generation as part of an environmental protection effort. Furthermore, the habitat report and the recommendations have been used by the Service in its "consultation" (under Section 7 of the Endangered Species Act) with the U.S. Bureau of Reclamation (BuRec) and Western to prepare a draft Biological Opinion on the impact of Flaming Gorge operations on the endangered fish. In the draft opinion (released in February 1992), both BuRec and Western endorsed the report's finding that current dam operations

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[2] Tyus, Harold M. and Karp, Catherine A., "Habitat Use and Streamflow Needs of Rare and Endangered Fishes, Yampa River, Colorado," U.S. Fish and Wildlife Service Biological Report No. 89(14), July 1989.

[3] See Tyus and Karp, supra note 2.

[4] See Tyus and Karp, supra note 2.

[5] Tyus and Karp, "Habitat Use and Streamflow Needs of Rare and Endangered Fishes in the Green River, Utah," Final Report, U.S. Fish and Wildlife Service, July 31, 1991.

adversely affect the fish.[6] The specific flow recommendations contained in the draft are proposed as the basis for a five year study of the fish recovery effort and are similar, with some minor exceptions (e.g., duration of spring high flows) and one major exception (short duration very high spring flow), to those in the habitat use and streamflow report.

Following a review of the comments on the draft, the final Biological Opinion was released in November of 1992[7] and its recommendations were incorporated into the Recovery Action Plan of the Recovery Implementation Program -- the comprehensive plan for recovery of the endangered fishes in the entire upper basin of the Colorado.[8]

Notwithstanding the fact that Flaming Gorge reservoir will now be operated in a way that will take some account of the needs of endangered species, the recommended flows are only a first step. A review of all of the RIP's instream flow recommendations points out that for the Green River the recommended "...peak flows are not very high and the baseflows are not very low by predam standards (i.e., the ratio of peak to baseflow is 40 on predam flow records, whereas the recommended ratio is 12)."[9] The review concludes from this that the "...flow recommendations may not do much ecological good, especially if the peaks do not accomplish much channel reconfiguration and baseflow fluctuations for hydropower operations do indeed compromise stability of the food webs."[10]

The data already collected by the Service and reinforced by the opinions of its biologists make it clear that recovery of the Colorado River endangered fishes will not be accomplished without modifying flows that are controlled by federal dams. It is clear as well that even in those cases, like Flaming Gorge, where changes have already been made, more may need to be done. The instream flow review has recommended that a management process be put in place "...to adaptively respond to the implications..." of learning more in the future about the habitat needs of the fish.[11]

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6 Fish and Wildlife Service, "Draft Biological Opinion on the Operation of Flaming Gorge Dam," February 11, 1992.

7 Fish and Wildlife Service, "Final Biological Opinion on the Operation of Flaming Gorge Dam," November 25, 1992.

8 Fish and Wildlife Service, "Draft Recovery Implementation Program Recovery Action Plan," September 1993.

9 See Stanford, supra note 1.

10 See Stanford, supra note 1.

11 See Stanford, supra note 1.

The Missouri River

Though there is no basinwide endangered species recovery program in the Missouri, it does share with the Colorado conflicts that revolve around the operation of the river's large federal dams. These conflicts have forced the U.S. Army Corps of Engineers to conduct a formal review of its Missouri River Master Water Control Manual (Master Manual). This review raises a host of issues about the current operation of the river's dams for hydropower generation, navigation, flood control, endangered species protection, wildlife enhancement, and other environmental benefits. An analysis of the preliminary DEIS by the Environmental Defense Fund in the summer of 1993 led it to ask the Corps a variety of questions about the relationship between "economic uses" (e.g., flood control, navigation, hydropower, and recreation) and environmental values (e.g., wetlands, cold and warm water fish habitat, endangered species habitat, and riparian habitat).[12]

In its comments on the preliminary draft, EDF urged the Corps to utilize a run-of-the-river baseline throughout the DEIS and an historic reference point -- the natural hydrograph -- when discussing fish and wildlife and their habitat. EDF also suggested that the Corps develop an optimal environmental alternative for inclusion in the DEIS, give preference to native species in its modeling analysis, pay special attention to the pallid sturgeon, consider the employment of an adaptive management model as the basis for restructuring the Master Manual, and include a Preferred Alternative in the DEIS. EDF also recommended a thorough review of power generation, navigation support and flood control. In addition, EDF encouraged the Corps to revise and expand its river and habitat modeling capability in such a fashion as to allow it to assess the implications of employing an ecosystem approach to managing the basin.

In early May of this year the Corps released a summary of the Preferred Alternative that will be part of the Draft Environmental Impact Statement (DEIS) scheduled for release in June. An initial assessment of the summary suggests that the Corps has done little, beyond identifying a Preferred Alternative, to respond to comments it received on the preliminary DEIS. Should this tentative conclusion be verified after reviewing and analyzing the DEIS when it becomes available, it suggests a protracted conflict over the Master Manual review process and a parallel struggle over dam operations in the basin.

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[12] Environmental Defense Fund, "Comments on the Preliminary Draft Environmental Impact Statement for the Missouri River Master Water Control Manual Review," Boulder, Colorado, August 1993.

APPENDIX C

DRAFT PROPOSED DECISION MAKING CRITERIA AND STANDARDS FOR THE WESTERN AREA POWER ADMINISTRATION

1.00 Purpose and Scope

1.01 Purpose. The purpose of these regulations is to establish a process that will determine the criteria and standards for the public process relating to transmission and purchase power decisions of the Western Area Power Administration ("Western").

1.02 Scope. These regulations will apply to Western's investments in new or upgraded transmission lines and purchase power agreements that are in excess of $3 (three) million.

2.00 Assessment of Alternatives

2.01 Objective. Western shall make a thorough and consistent assessment of a wide range of alternatives for any project covered under the scope of these regulations.

2.02 Demand-Side Assessment. As an alternative to any transmission investment or purchased power expense covered under these regulations, Western will examine a wide range of energy efficiency options that could potentially achieve the same underlying objective.

2.03 Supply-Side Assessment. As an alternative to any transmission or purchased power expense covered under these regulations, Western will examine a wide range of supply-side acquisitions, including renewable resources, that could potentially achieve the same underlying objective.

2.04 No-Action Alternative. Western shall also consider a no-action alternative for each project covered under these regulations.

2.05 Uncertainty Analysis. In analyzing the economics of any given alternative, Western will consider how that alternative would perform under a wide range of reasonable alternative circumstances. These alternative circumstances might include, but are not limited to, higher fuel prices, more stringent environmental regulations, and alternative competitive structures of the utility industry.

2.06 Effects on Resource Development. Western will also consider whether and, if so, how any investment covered by these regulations may encourage development of a particular type of utility resource.

3.00 **Decision Criteria and Standards**

3.01 Core Standard. Western will select the option with the lowest total cost including utility, customer, and environmental costs in choosing among the various alternatives identified as a result of the analysis carried out under the provisions of Section 2.00.

3.02 Other Considerations. Western may depart from a resource with the lowest total cost in choosing among alternatives to protect system reliability or to manage planning or financial risks. To the extent that Western does depart from the total resource cost standard, Western will provide a comprehensive discussion of the reasons supporting such a departure.

4.00 **Public Process**

4.01 Objective. An objective of these regulations is to encourage public involvement in the review of Western's major investments.

4.02 Proposed Decision. Towards this end of encouraging public review, Western will provide a written description of the results of its analysis in the form of a proposed decision.

4.03 Public Comment. Once a proposed decision is available (reached consistent with the provisions in these regulations), Western will make it available to the public for comment.

4.04 Final Decision. Upon receipt of the public comments, Western will develop a final decision. As part of the final decision, Western will address and respond to any comments received that in any way suggest that the Final Decision is inconsistent with these regulations.

5.00 **Energy Efficiency and Renewable Resource Incentives**

5.01 Overall Goal. The overall goal of the energy efficiency and renewable resource incentives is to encourage Western's customers to meet the future demand for energy services in an economically and environmentally sustainable manner.

5.02 Resource Pool. Western commits to devote at least two (2) percent of its gross revenues to provide incentives for its customer utilities to invest in energy efficiency and renewables.

5.03 Technical Assistance. This resource pool will be allocated to Western's customers in the form of technical assistance directed toward acquisition of energy efficiency and renewables as a resource. As such, the assistance might help utilities with program design, provision of upfront financing, co-funding of experimental projects, or after-the-fact monitoring and evaluation activities.

5.04 Small Customer Set-Aside. To ensure equity between small and large customers, Western will set-aside a fixed amount that will only be eligible to "small" utilities -- those with annual energy requirements of under 1,000 GWh.

Mr. MILLER. Mr. Paul Little.

STATEMENT OF PAUL LITTLE

Mr. LITTLE. Thank you, Mr. Chairman.

Mr. Chairman and members of the committee, I would like to express the appreciation of the 28 Indian tribes of the Missouri River Basin for scheduling this oversight hearing.

I am here today to represent the Missouri Basin Tribes. I was the first chairman of the Mni Sose Inter-tribal Water Rights Coalition, which was formed for two basic purposes: one, to protect, preserve and develop the Winters Doctrine water rights of the tribes of the Missouri River Basin and its tributaries and aquifers; and two, to work with Western Area Power Administration and Congress to obtain an allocation of Western power resources for the Missouri River Basin Tribes.

Mr. Chairman, the tribes of the Missouri River Basin have worked at least since the early 1980s with the Western Area Power Administration to advance the need for low-cost Federal power on the Indian reservations. Western advised us that our opportunity to participate was foreclosed until Western reallocated its power in the year 2000 or thereabouts in the Missouri River Basin.

We have participated in countless meetings with Western and filed comments as formally required in the public process. We have taken every step we know to present our needs to Western.

We have participated for well over a decade. The tribes of the Missouri River Basin are convinced that legislation is required to correct the Secretary of Energy and the administrator of Western to reserve sufficient power from existing customers to meet the electrical needs of the Missouri River Basin tribes.

Western will not act without direction from Congress. As recently as 1991, Western was advising us that consideration would be given to reallocating 70 to 98 percent of the power resources to existing customers. Western's Draft Environmental Impact Statement made available in April 1994 addresses reallocation to existing customers of 90 to 98 percent of Western's power resources, a significant reduction in power to new customers and a message that tribes have little hope of success through Western.

There is an economic need for allocation of Federal power to the Indian tribes. The need is based on the fact that electrical rates on Indian reservations of the Missouri River Basin are among the highest and the capability to pay these high costs by the tribal membership is the lowest in the Nation.

The statement of Mr. Between Lodges, which I submitted for the record, presents statistics that are important to the Committee. I urge that the committee take note of the fact that electrical costs in South Dakota range from 45 to 82 mils per kilowatt hour and the cost on the Indian reservations are generally above 72 mils per kilowatt hour.

In South Dakota per capita income averaged $10,600 annually. And on the Indian reservations it averaged $2,700 to $4,800 annually. For economic reasons alone, I respectfully submit that there is a need for allocation of Western power to the tribes.

I have personal experience with the high cost of electricity on the Pine Ridge Indian Reservation. As a tribal councilman for several terms I was approached by members of the tribe many times seeking help in the payment of their electric bills. You cannot imagine the concern of these people when they receive monthly power bills as high as three to $400 per month. The level of income on the reservations is so low that these kind of monthly payments are impossible.

I did what I could to obtain funds to assist tribal members in the payment of electric bills, but neither the tribe nor the individual can afford these costs. Western has historically resisted sale of power to the tribes. The Draft EIS reflects Western's attitude that little if any power will be made available to new customers, including the Indian tribes of the Missouri River Basin.

There is no doubt that Western will continue to require the Indian tribes and other new customers to have utility status. This is an unreasonable requirement. Western has discussed a concept they call energy credits. If this concept was adopted by Western and agreed upon by the utilities serving the reservation, the tribal membership could receive Western power in their home without the need for utility status. Without that kind of breakthrough the tribes are forced to become utilities.

The tribes are not encouraged by the creative thinking of Western on energy credits. There is more concern from the tribes that Western will not sell power to the tribes. Mr. Chairman, members of the committee, I respectfully submit that legislation will be required to direct the Secretary of Energy and the administrator of Western to revise its criteria for allocation of power. Absent legislation, the tribes are convinced that Western will not address our needs because we are not existing customers, and for the most part we are not utilities.

The reallocation of Western energy in the Pick-Sloan project in the year 2000 creates an opportunity for addressing Winters Doctrine reserved water rights for the tribes in the Missouri River Basin.

At present the sole federal effort in the Missouri River Basin with regard to our water rights is to subject them to State court, the McCarran amendment, the adjudication proceedings, or to negotiate our water rights under the threat of State court adjudication. Both processes are destroying our Winters Doctrine water rights and the spirit of the Indian people.

The Winters Doctrine water rights claims of the Missouri River Basin tribes are largely unused for several reasons. These include, one, diminishment of the quantity and quality of reservation streams and aquifers to the point where they are unusable; two, absence of Federal funds for development of Indian water projects during most of the century; and three, the current policy of the United States to subject our water rights to State courts or State negotiations.

Our unused water rights are currently generating hydropower and other benefits in the Missouri Basin. Many tribes, perhaps not all, feel strongly that the United States could recognize an amount of water that we claim and preserve that supply for the continued generation of hydroelectric power and other Missouri Basin Pick-Sloan benefits.

In this manner, the tribe would retain their Winters Doctrine water rights and receive power or power revenues from Western. Tribes would be in a position to judge for themselves whether the benefits from Pick-Sloan or diversion to the reservation purposes has the greatest economic value.

The Coalition's statement deals with this matter in detail. There would be many specifics to work out, but the idea is workable. For the first time in this century the tribes of the Missouri River Basin would have a progressive approach respecting our water rights rather than destruction of our water rights and our hopes that is now ongoing in the State forums.

The States, Western's existing customers and others could have little concern with our concept; and the tribes' Winters Doctrine rights would be retained by our people and would produce economic benefit.

To accomplish the purposes set forth above, the Mni Sose Coalition has determined that 25 percent or more of Western's power would be required by the Missouri River Basin tribes. Western's existing customers are concerned about loss of power resources they now control. Our preliminary estimates disclose that an average increase in the rates to the consumers receiving Western power would be on the order of 2 percent, assuming 25 percent of the power resources are allocated to the Missouri River Basin tribes.

Mr. Chairman, on behalf of the tribes, I respectfully submit that the monopoly of Western power by existing customers must end. Existing customers argue that preservation of their rates must be continued. I argue that preservation of their rates perpetuates our poverty. This is an area of Federal policy. Many meaningful changes can and should be made. The impact on existing customers cannot be greater than the impact we currently suffer because we are not customers.

Western's EIS cannot continue until an additional alternative is developed that would direct a meaningful allocation to us.

Mr. Chairman, I thank you and the members of the Committee for the opportunity to address these remarks to you. The tribes of the Missouri River Basin look forward to the two-week period after this hearing to submit additional statements for the record.

[Editor's note.—See Appendix.]

Mr. LITTLE. I trust that the time frame will be acceptable. Thank you.

Mr. MILLER. It will be. Thank you.

[Prepared statement of Mr. Between Lodges and attachments follow:]

TESTIMONY
WILBUR BETWEEN LODGES, PRESIDENT
OGLALA SIOUX TRIBE

REPRESENTING
MNI SOSE INTER-TRIBAL WATER RIGHTS COALITION
OF THE MISSOURI RIVER BASIN

Respecting
House Natural Resource Committee Oversight Hearing on
Western Area Power Administration Allocation of
Federal Power

1. History of Mni Sose Coalition Objectives.

Oglala Sioux Tribe Resolution 93-103 was supported by the Mni Sose Coalition in Coalition Resolution 93-04 as follows:

> *...That the Board of Directors for the Mni Sose Inter-Tribal Water Rights Coalition hereby supports the request of the Oglala Sioux Tribe for Congressional Oversight Hearings to address: (1) the need for low-cost electrical energy on the Pine Ridge and other Indian Reservations in the Missouri River Basin; (2) the need for comprehensive re-evaluation of the criteria for allocating Pick-Sloan power resources by the Western Area Power Administration; and (3) the need for acquisition of the local rural electrical cooperatives, in part or in whole, or alternatively the need to transport low-cost federal energy across the transmission and distribution systems of the local rural electrical cooperatives for the benefit of the Oglala Sioux Tribe and the membership of all Missouri River Basin tribes.* (Mni Sose Resolution 93-04, June 14, 1993).

By letter of May 25, 1994, the Executive Director of the Mni Sose Coalition authorized the Oglala Sioux Tribe to proceed with the preparation of testimony for the June 16, 1994, hearing before the House Natural Resource Committee:

> *In accordance with Resolution No. 93-04, the Oglala Sioux Tribe is authorized to present Tribal concerns on WAPA Hydropower Allocation Process and the WAPA Environmental Impact Statement on behalf of the Mni Sose Inter-Tribal Water Rights Coalition to the House of Representatives' Committee on Natural Resources...*

The Coalition and the Oglala Sioux Tribe are supported by the National Congress of American Indians (NCAI) Resolution SF-91-73. The NCAI resolution supports the Missouri River Basin Tribes in their effort to reserve not less than 25% of the Missouri River Basin Pick-Sloan federal power resources for allocation to Missouri River Basin Tribes:

NOW THEREFORE, BE IT RESOLVED, that the National Congress of American Indians supports the allocation of not less than 25% of the Missouri River Basin Pick-Sloan Federal Hydropower to the 26 tribes of the Missouri River Basin as the highest and best use of the Federal energy produced by the United States from the Missouri River.... (NCAI Resolution SF-91-73).

Figure 1 shows the location of the Tribes within the Missouri River. Coalition members include 22 of the 28 tribes in the basin. It is respectfully submitted here that all member and non-member tribes have a common interest in the allocation of Western power.

2. Need For Allocation of Federal Power to Indian Tribes.

There is a compelling *need* for direct allocation of federal low-cost power to the Indian tribes of the Missouri River Basin. **The need is based upon the fact that the cost of electricity to the Indian tribes and their members is high and the income levels are among the lowest in the nation.** In the Missouri River Basin a massive federal project was initiated by the Flood Control Act of 1944, and over 2,000 megawatts of power are produced by the federal project, know as the Missouri River Basin Pick-Sloan program. The United States has the capability and responsibility as Trustee to meet the electrical needs of the Indian people in the Missouri River Basin. Aside from *need* arising from above-average costs of electricity (costs on some reservations are the highest in the Missouri River Basin) and the least capability to afford those costs (per capita income levels on some Indian reservations are the lowest in the nation), there are further compelling reasons for allocating federal power from the Missouri River Basin Pick-Sloan Project to the Indian tribes. These reasons include the following:

- It is urgent that the United States provide an alternative water supply from the Missouri River until such time as the United States can restore the quantity and quality of *Winters* doctrine streams and aquifers that have been diminished and left unusable by Bureau of Reclamation and other projects. A replacement supply of water from the Missouri River needed to restore tributary streams and aquifers is now producing hydropower marketed by the Western Area Power Administration. Electricity produced by replacement waters should be made available to the Tribes until tributary streams and aquifers are restored.

- In addition to *Winters* doctrine water rights on streams and aquifers that have been diminished by Bureau of Reclamation and other projects, the tribes possess valuable *Winters* doctrine rights in streams and aquifers of the Missouri River Basin with adequate quantity and quality that are unused because funds have not been available to develop those water supplies. The United States has been unwilling to assist the tribes in significant water resource development. Rather than development, the United States has sought to quantify Indian water rights by (1) McCarran Amendment adjudication proceedings in state courts or (2) negotiated settlement of water rights between the states and the tribes. There is

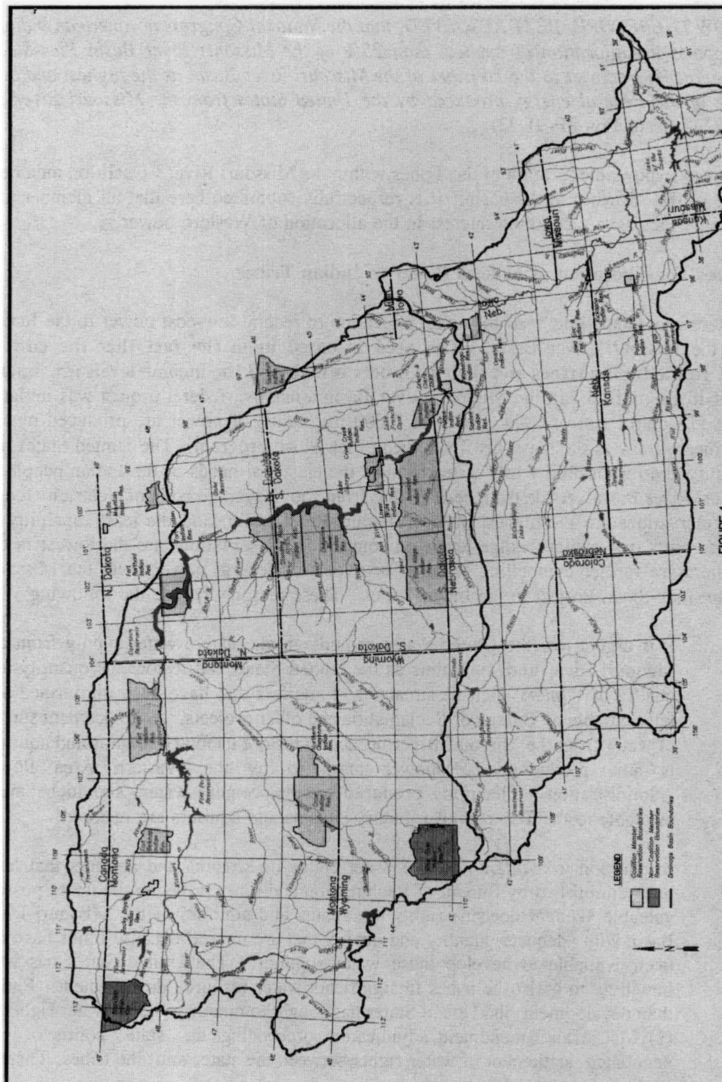

FIGURE 1
THE INDIAN SURFACE WATERS OF THE MISSOURI RIVER DRAINAGE
Prepared By: Oglala Sioux Tribe

a need for the United States to abandon its policy of diminishing Indian water rights by state court adjudication or state negotiation and use the machinery of the Missouri River Basin Pick-Sloan project to acknowledge the nature and extent of the *Winters* doctrine and provide benefits to the tribes through allocation of federal power or power revenues produced by unused *Winters* doctrine water rights.

- There is a need for the United States to properly compensate the Indian tribes along the Missouri River and tributaries where lands were taken for construction and filling of the Missouri River Basin Pick-Sloan reservoirs and construction of navigation channels. The tribes were inadequately compensated for the takings of these lands. Congress has taken corrective action on the Fort Berthold and Standing Rock Indian Reservations. Similar actions are needed on other Indian reservations along the Missouri River and tributaries where Indian lands were taken for dams, reservoirs and navigation channels. An allocation of Western power to these tribes is a means, among others, of properly compensating tribes for the taking of their lands.

Each of the Missouri River Basin tribes has an immediate need for low-cost federal power to reduce the cost of electricity for its membership. There can be no question that the Western Area Power Administration and its predecessor, Bureau of Reclamation, have *chilled* any effort on the part of the tribes (since approval of the Missouri River Basin Pick-Sloan project in December 1944) to obtain low-cost federal power. The tribes were out competed by municipalities inside and outside the Missouri River Basin. The Bureau of Indian Affairs made no effort to assist the tribes in receiving allocations of this precious resource.

Each tribe must speak individually with regard to its needs for power until such time as water supplies and water quality of tributary streams and aquifers are restored where tribes have water rights upstream and downstream from Bureau of Reclamation projects. Similarly, each tribe must address the merits of the proposition presented here that un-used *Winters* doctrine water rights can be preserved by the United States and federal power or power revenue produced by the machinery of the Pick-Sloan project can be allocated in accordance with water claims until water is used by the Tribes. The course of the United States at present is to degrade and diminish Indian rights and the spirit of the Indian people through adjudications and settlements with the states. Each tribe can address the merits of Western power or power revenue allocations as compensation, in part or in whole, for taking of lands for the Pick-Sloan project.

In addition to the economic need of an impoverished people for a reservation of power marketed by the Western Area Power Administration, there are other federal purposes that could and should be addressed in Western's power marketing initiatives all as set forth above.

3. **Petition for Legislation Directing the Reservation From Marketing of Western Power for the Missouri River Basin Tribes.**

The Missouri River Basin Coalition petitions Congress to enact legislation directing the Secretary of Energy and the Administrator of the Western Area Power Administration to reserve not less than 25% of the power resources of Missouri River Basin Pick-Sloan for the use and benefit of the Oglala Sioux and other Missouri River Basin Indian tribes.

The Draft Environmental Impact Statement prepared by Western addresses a limited range of alternatives that would allocate from 90-98% of the power resources to existing customers, none of which are the tribes of the Missouri River Basin. Of the 2% to 10% of the power resources not re-contracted to existing customers, Western's draft EIS is silent on the method of allocating to new customers. It is clear that historic practice would govern, however. The historic practice has been to allocate power exclusively to existing *preference* customers with *utility* status. All tribes have *preference* status but few have *utility* status over large areas of their reservation, and requirement for *utility* status has been a barrier that the Tribes have not overcome. Many Tribes in the Missouri River Basin, including the Oglala Sioux, have or will undertake steps to partition and acquire parts of existing REC's in order to achieve *utility* status.

The requirement of *utility* status is so prevalent in the thinking of Western and its existing customers that instances can be cited where the existing customer utilities have refused to wheel federal power to the tribes (assuming they could receive a Western allocation) on the basis that the Tribes are not utilities. The White Mountain Apache Tribe in Arizona, where electrical costs are among the highest in the nation, can cite this experience. Not only does Western deny the tribes an allocation of power on the basis that Tribes do not qualify as utilities, the existing customer utilities of Western refuse to wheel (transport) power to the tribes unless they have *utility* status.

Only Congressional direction will change the course of Western on the issue of *utility* status. There is no hope that administrative processes can be used to overcome the barrier of *utility* status. The federal courts have repeatedly acknowledged the power of the Secretary to exercise discretion with regard to allocations of federal power and who qualifies as a preference entity.

The collective tribes of the Missouri River Basin respectfully petition the Committee to draft legislation that is essential to the Indian tribes for meaningful participation in the allocation of Western power resources[1].

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[1]The Mni Sose Coalition opposed S. 1370 sponsored by Senator Burns of Montana. His bill was made part of Public Law 102-575, the Reclamation Projects Authorization and Adjustment Act of 1992, and directed the Secretaries of Interior and Energy to make Western Pick-Sloan power available to non-Pick-Sloan irrigation projects in Montana (Hammond and Haidle). We objected on the grounds that comprehensive direction was needed from Congress in re-allocation of Western power. Our objection was withdrawn on the basis of assurances that a more comprehensive Congressional review would be undertaken. (See Appendix B, October 23, 1991, Testimony).

4. Western's Requirement for Utility Status Can be Overcome by Energy Credits.

The principle difficulty that the Oglala Sioux and other tribes of the Missouri River Basin have in achieving success in application to Western for allocation of federal power is the distinction between *preference* and *utility* status.

The 1944 Flood Control Act, which approved the Missouri River Basin Pick-Sloan program and the construction of the federal facilities that produce power marketed by Western provided as follows:

> *Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The Secretary of the Interior is authorized from funds to be appropriated by the Congress, to construct or acquire, by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at such projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives and privately owned companies....* (58 Stat. 887, 890).

Preference in the sale of electricity is further defined by Reclamation law as follows:

> *...That in said sales* [of electric power and energy] *or leases, preference shall be given to municipalities and other public corporations or agencies; and also to cooperatives and other non-profit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936...* (43 USC 485h(c))

Western has historically marketed as much as 12.3 billion kilowatt hours of energy from the Missouri River mainstem dams. The energy was marketed to the following entities, of which none of the municipalities or other customers were Indian tribes, Indian reservations or Indian municipalities.

Entity	Billion kwh	Percent
211 Municipalities	3.9	32
Rural Electric Cooperatives	5.3	43
Public Utilities	1.3	11
Private Utilities and Other Customers	1.8	14
	12.3	100

The Indian tribes, including the Oglala Sioux Tribe, were not able to compete for the federal power produced by MRB-PS when the 211 municipalities, utilities and other customers received their initial allocations of this valuable resource. As the Oglala Sioux Tribe became aware of the significant economic value of hydropower produced by MRB-PS, it was discouraged from seeking any allocation of Western power on the basis that (1) the Tribe is recognized as a *preference* entity but (2) the Tribe is not recognized as a *utility*.

Utility status is defined and applied as follows by Western:

> *...The primary consideration of 'utility status' is that an entity must control and operate its own distribution system. Since Western has not taken action on the proposed allocation criteria, and the interim Navajo Surplus will be sold under the provisions of Section III. B. 3 of the Interim Plan, this factor will only be considered if a conflict arises over contracting with a utility or a non-utility.* ***Western will first contract with the entity considered to have 'utility status'****....*(59 FR 8264, Withdrawal of Proposed Allocation Criteria, Allocations, and Rates for Interim Power from Navajo Generating Station, Western Area Power Administration). (Emphasis supplied.)

The Federal Courts have addressed the broad powers of the executive branch in allocating electricity. In the *City of Santa Clara v. Andrus* (572 F.2d 666), the U.S. 9th Circuit Court of Appeal addressed the executive discretion of the Secretary:

> *...The preference clause requires only that public entities be given a preference over private entities in the marketing of power generated by federal reclamation projects...it does not require that all preference customers be treated equally or that all potential preference customers receive an allotment...Where, as here, one preference entity challenges the Secretary's decision to discriminate against it in favor of other preference entities, the reclamation laws provide no law to apply to the dispute. If he so chooses, the Secretary can market all available...power to a single public entity without running afoul of the preference clause.*

Certainly the 9th Circuit did not prohibit the Secretary of the Interior or his successor (Secretary of Energy) from allocating power to a non-utility, preference customer. The 9th Circuit simply found that the Secretary [of Interior] had broad powers in the interpretation of the *preference* clause.

The Oglala Sioux Tribe and other tribes of the Missouri River Basin do not have *utility* status over large areas of the reservation. The Oglala Sioux Tribe owns distribution facilities within Pine Ridge Village, the largest community on the Reservation. The distribution system is administered pursuant to an operation and maintenance agreement with Nebraska Public Power District.

Outside the community of Pine Ridge Village, the Oglala Sioux Tribe has *preference* but not *utility* status. As many as 15,000 residents are served by rural electrical cooperatives of the reservation, including West Central REC, West River REC, Black Hills REC, and, most notably, Lacreek REC. The latter serves approximately 90% of the geographical area of the Reservation. Our circumstances are typical of other Missouri River Basin Tribes. Without Congressional direction to the Secretary of Energy and the Administrator of the Western Area Power Administration, it is clear from the foregoing that *utility* status will remain a major constraint in the allocation of Western power directly to the Tribes.

The Oglala Sioux Tribe is addressing the need for *utility* status throughout the Western two thirds of the Pine Ridge Indian Reservation. The Board of the Lacreek REC has agreed to receive a proposal from the Tribe to separate the REC into two parts, a western and an eastern part. Future decision and voting by Lacreek REC membership will hinge to some degree on the effect on rates of dividing the REC. Other tribes are also considering formation of new REC's from larger, established REC's; but Boards of Directors will be reticent to cooperate as Lacreek has cooperated. Tribes are forced to form new REC's because Western currently requires *utility* status. Additionally, tribes seek greater employment opportunities and greater participation in REC management and decision - making. Reservation REC's are presently operated and controlled by non-tribal staff and board members.

It is respectfully submitted that Western can allocate power to the Oglala Sioux and other tribes of the Missouri River Basin irrespective of *utility* status. This can be accomplished by *energy credits*. Western staff have defined *energy credits* as a calculation, rather than a measurement of Western power delivered to end users. The *energy credit* concept was conceived to address the difficulty created by the deliver of Western power to numerous locations with few, if any, demand meters to actually measure power used and the time of use. Western staff agree that reasonable calculations can be made of demand, provided Western, the local rural electrical cooperative (or other utility) and the Western customer (Oglala Sioux or other Missouri River Basin tribes) agree on the demand calculation.

Discussion of *energy credits* was related to the delivery of Western energy to approximately 250 individual households on the Pine Ridge Indian Reservation to account for power used by domestic wells. The concept of *energy credits* used here, relates to the delivery of Western power to all households of members of the Oglala Sioux and other tribes throughout the Missouri River Basin reservations for all purposes, not limited to pumping from domestic wells. If the concept is valid in a limited application, the concept can be adapted to a broader application. *Energy credits* becomes the means by which Western can deliver federal power to the members of the Indian tribes throughout the Missouri River Basin without requiring *utility* status.

Lengths have been taken in this discussion to provide an example of the mechanism for allocating Western power resources to non-utility, preference tribes throughout the Missouri River Basin. The Draft EIS recently prepared by Western does not address this mechanism. The Draft EIS is deficient because it does not address how allocations of power to new customers that are not utilities will be made. Nor does the Draft EIS address the future Western policy on the requirement for *utility* status.

5. Need for Low-Cost Federal Power of the Oglala Sioux and Other Indian Tribes of the Missouri River Basin.

The proposed federal action in the draft EIS addresses allocation of Western resources in...*an equitable manner consistent with Western's legal obligations and constraints*.... Western does not fully identify its legal obligations and constraints. It only refers to legislation requiring energy conservation by its customers. Nor does Western identify standards for the equitable manner in which power will be allocated. It is respectfully submitted that there can be no greater federal purpose and no more equitable allocation of Western power than on the basis of the ability to pay. The Indian tribes of the Missouri River Basin, particularly the Oglala Sioux Tribe, do not have the ability to pay the current high costs of electricity within their reservations.

Tables 1 and 2 demonstrate that the RECs serving the Indian reservations have costs that are above median in South Dakota (Table 1) and near median or above in North Dakota (Table 2). Exceptions are part of the Rosebud Indian Reservation served by Cherry Todd REC in South Dakota and part of Fort Berthold Indian Reservation served by McKenzie REC in North Dakota.

Costs of electricity range from 43.8 to 81.9 mils ($0.0438 to $0.0819) per kilowatt hour in South Dakota. With the exception of service by Cherry Todd REC on Rosebud, all costs on the South Dakota Indian reservations are 70 mils per kilowatt hour or above. Annual per capita income of Indians on the Indian reservations in 1990 ranged from $2,747 (Standing Rock) to $4,850 (Lower Brule). This compares with per capita income in the State of South Dakota (including low-income Sioux) of $10,661.

In North Dakota, Fort Berthold and Fort Totten (with the exception of the area served by McKenzie REC) have electrical costs between 60 and 65 mils per kilowatt hour. Standing Rock has electrical costs of 72 mils per kilowatt hour from Mor-Gran-Sou REC. Annual per capita income levels on the Indian reservations in North Dakota (Indians only) range from $3,907 (Standing Rock) to $4,864 (Fort Berthold). The average annual per capita income in the State of North Dakota is $11,262, including in the average the low-income of the Indian population.

Tables 1 and 2 underscore the fact that the tribes of the Missouri River Basin in the Dakotas generally pay above median costs and they cannot afford the high cost of electricity that they receive. The effect in South Dakota is shown in Table 3. Table 3 summarizes revenues and patronage capital (gross income from sale of electricity) derived from residential usage. Lacreek REC, which serves the Oglala Sioux Tribe on Pine Ridge and the western part of the Rosebud Indian Reservation, derives 92.2 mils per kilowatt hour ($0.0922 per kilowatt hour) from residential power use. Lacreek REC also has the least amount of residential electrical power use of the 32 REC's in South Dakota (634 kilowatt hours per consumer month). Thus, it is clear that the high cost of power drives usage on the Indian reservations to low levels. Similarly, power used for residences within Moreau Grand REC on the Cheyenne River and Standing Rock reservations averages 686 kilowatt hours per month, second lowest of the 32 REC's in South Dakota. Off the reservations, electrical use for residential purposes exceeds 1,600 kilowatt hours per month in the instance of Codington Clark REC.

The rural electrical cooperatives dispute the statistics presented here on the grounds that the statistics do not properly reflect conditions between RECs. The statistics, however, were derived from data published by the Rural Electrification Administration (REA) in 1992 (latest year of publication) and are intended to standardize information for comparison between REC's, states and regions. Despite some validity that the REC's may have in challenging the statistics because of differing conditions within the REC's, the overall conclusion is compelling. Namely, the costs of electricity on the Indian reservations are higher than off the reservations, the Indian people have the least capability to pay, and there is generally lower usage on the Indian reservations for residential purposes. While not documented, except by word of mouth, we know that many tribal members go without adequate heat in the cold of winter.

TABLE 1

COSTS OF ELECTRICITY - 1992
SOUTH DAKOTA RECS

REC	Reservation	Number	Unit Costs (mils per kwh): Cost of Power (35/67)	All Other Costs (34-35)/67	Total Operating Deductions (34/67)	Rank	1990 Per Capita Income
Spink		34	46.9	35.0	81.9	1	
Lacreek	PR/Ros	35	46.4	32.9	79.3	2	$3,121/4,005
Union County		6	44.1	33.4	77.4	3	
Cam Wal		31	48.1	29.0	77.1	4	
Moreau Grand	CR/SR	38	47.1	30.0	77.1	5	$4,077/2,747
Black Hills		13	43.0	33.2	76.2	6	
Ree		29	46.9	28.4	75.4	7	
Charles Mix	Yanton	32	44.6	30.0	74.6	8	$2,834
Oahe		37	43.3	30.9	74.2	9	
Beadle		33	46.1	27.7	73.8	10	
West Central	Lower Brule	42	46.1	26.7	72.8	11	$4,850
Tri-County	Crow Creek	25	43.7	28.9	72.6	12	$3,717
McCook		28	45.6	27.0	72.6	13	
Clay Union		3	43.4	28.7	72.1	14	
Intercounty		23	45.0	26.3	71.2	15	
West River		11	43.2	27.6	70.8	16	
Fem		36	43.0	25.7	68.7	17	
H-D Electric		17	45.1	23.6	68.7	18	
Butte Electric		15	43.9	24.3	68.2	19	
Bon-Homme-Yankton		27	43.9	24.2	68.1	20	
Douglas		39	44.5	23.2	67.7	21	
Sioux Valley Empire		12	43.9	23.5	67.5	22	
Lake Region		20	43.6	23.5	67.0	23	
Cherry Todd	Rosebud	41	43.6	22.9	66.5	24	$4,005
Kingsbury		30	43.5	23.0	66.4	25	
Turner-Hutchinson		19	44.2	20.9	65.1	26	
Codington Clark		18	43.0	21.3	64.3	27	
Lincoln-Union		7	41.5	22.7	64.2	28	
Whetstone Valley		16	43.3	20.1	63.4	29	
Northern Electric		21	39.9	16.1	56.0	30	
Rosebud		26	22.3	21.6	43.9	31	
Grand		40	29.0	14.8	43.8	32	
State Of South Dakota							$10,661

Notes: PR - Pine Ridge, Oglala Sioux
CR - Cheyenne River, Cheyenne River Sioux
Ros - Rosebud, Rosebud Sioux
SR - Standing Rock, Standing Rock Sioux

TABLE 2

COSTS OF ELECTRICITY - 1992
NORTH DAKOTA RECS

REC	Reservation	Number	Unit Costs (mils per kwh) Cost of Power (35/67)	All Other Costs (34-35)/67	Total Operating Deductions (34/67)	Rank	1990 Per Capita Income
Slope		34	45.8	31.3	77.1	1	
Mor-Gran-Sou	Standing Rock	25	44.3	27.9	72.2	2	$3,907
James Valley		26	47.0	24.4	71.4	3	
Tri County		13	44.1	26.7	70.8	4	
Capital		35	46.5	22.5	69.0	5	
McClean		37	43.1	25.8	68.9	6	
KEM		27	28.1	39.2	67.3	7	
Burke-Divide		31	38.0	27.5	65.5	8	
West Plains		33	50.3	15.0	65.3	9	
Sheyenne Valley	Fort Totten	30	36.7	27.9	64.6	10	$3,933
Williams	Fort Berthold	28	36.2	27.3	63.5	11	$4,864
Baker Electric	Fort Totten	8	40.7	22.4	63.1	12	$3,933
Bottineau		22	43.1	19.3	62.4	13	
Oliver-Mercer		32	49.0	11.3	60.2	14	
Cavalier		38	38.3	21.0	59.2	15	
McKenzie	Fort Berthold	29	40.2	18.1	58.3	16	$4,864
R. S. R.		21	42.3	15.4	57.7	17	
Verendrye		17	36.3	13.3	49.6	18	
Nodak		19	34.4	12.0	46.5	19	
Cass County		11	30.7	15.4	46.1	20	
State Of North Dakota							$11,262

TABLE 3

REVENUES BY CLASS OF CONSUMER - 1992
SOUTH DAKOTA

REC	Reservation	REA Number	KWH Per Cons Mon Reside (61/53)	Rank	Rev/Pat m/kwh Reside (69/61)	Rank
Lacreek	PR/Ros	35	634	32	92.2	1
Clay Union		3	1,006	22	91.9	2
Black Hills		13	835	27	91.2	3
Moreau Grand	CR/SR	38	686	31	89.2	4
West River		11	741	29	87.2	5
Cam Wal		31	1,000	23	85.9	6
Charles Mix	Yankton	32	1,124	17	85.8	7
Union County		6	1,198	14	83.2	8
Butte Electric		15	897	25	81.9	9
Spink		34	1,116	18	81.2	10
West Central	Lower Brule	42	746	28	79.5	11
Intercounty		23	1,247	11	79.5	12
Ree		29	1,203	13	79.4	13
Tri-County	Crow Creek	25	1,138	16	78.6	14
McCook		28	1,257	9	77.9	15
Bon-Homme-Yankton		27	1,256	10	77.8	16
Sioux Valley Empire		12	1,149	15	76.2	17
Fem		36	1,102	19	74.4	18
Lincoln-Union		7	1,345	6	74.4	19
Cherry Todd	Rosebud	41	893	26	74.0	20
Lake Region		20	1,068	20	73.5	21
Douglas		39	1,523	3	73.4	22
Oahe		37	928	24	72.8	23
Codington Clark		18	1,637	1	70.7	24
Kingsbury		30	1,590	2	70.6	25
H-D Electric		17	1,306	8	70.4	26
Beadle		33	1,221	12	70.3	27
Turner-Hutchinson		19	1,479	4	70.3	28
Whetstone Valley		16	1,383	5	68.0	29
Grand		40	715	30	65.5	30
Northern Electric		21	1,334	7	61.7	31
Rosebud		26	1,060	21	51.8	32

Notes:
PR - Pine Ridge, Oglala Sioux
CR - Cheyenne River, Cheyenne River Sioux
SR - Standing Rock, Standing Rock Sioux
Ros - Rosebud, Rosebud Sioux

There has not been adequate time in the preparation of this statement to cover all Indian tribes that belong to the Mni Sose Coalition or reside within the Missouri River Basin. Given time, similar statistics can be developed for Montana, Wyoming, Nebraska, Iowa and Kansas. The Coalition is prepared to develop this information for the Committee.

No greater federal purpose can be served in the allocation of Western power than to develop criteria to meet the economic needs of the Indian tribes in the Missouri River Basin. There are other reasons for allocating Western Area Power to the Indian tribes of the basin as presented in the sections of this statement that follow, but the need for electrical power at an affordable rate to the tribal membership has considerable force.

The Oglala Sioux Tribe and Mni Sose Coalition are prepared to respond to any objections by the REC's to increased rates caused by an allocation of not less than 25% of the Western power resources to the Indian tribes of the Missouri River Basin. The Draft EIS of Western shows that 10% withdrawal of Western power from existing customers would raise their rates by $21,798,000. The Oglala Sioux Tribe and the Coalition can demonstrate that purchases (from all suppliers) by the rural electrical cooperatives that are customers of Western total in excess of $1.3 billion annually. On the average, purchases from Western account for 15-20% of purchases from all suppliers. An increase of $21,798,000 in costs represents approximately 1.6% of the total costs of power. Because the cost of power is only part of the rate paid by the consumer, the effect of an increase on consumers will be far less than a 1.6% increase in rates. Western's analysis of 10% withdrawal from existing customers suggests that 25% withdrawal would raise costs of those customers by 4% for power. If operation and maintenance accounts for half of the costs, consumers would experience a 2% increase in rates of existing customers.

6. Need to Allocate Missouri River Hydropower to Tribes Until Water Supply and Quality of Indian Streams and Aquifers are Restored.

Throughout the Missouri River Basin there are countless examples of encroachment upon the prior and superior Indian *Winters* doctrine rights to the use of water. Some of these activities occurred prior to the 1944 Flood Control Act which developed the Missouri River mainstem system of dams, and part of the encroachment occurred after. The Bureau of Reclamation was one of the principle proponents of water resource development that encroached upon the streams of the tribes where *Winters* doctrine water rights were ignored. It is respectfully submitted that where water supply and water quality have been diminished to the point that the tribes cannot practically use their reserved water rights, there is a need for restoration of the streamflows and aquifers (both quantity and quality) in order for the tribes to exercise their *Winters* doctrine rights.

Until such time as the United States can restore the streams and aquifers of the tribes (both quantity and quality), replacement water is needed. The Pick-Sloan project is the physical mechanism that can replace the diminished water resources of the tribes from Blackfeet in the headwaters to Kickapoo in the lower basin. However, it is impractical to physically transport water from the Pick-Sloan project to many locations where tribal streams and aquifers have been encroached upon and diminished. Therefore, it is only practical in those instances to permit the replacement water supply to be used by the United States in the capacity considered most beneficial to the region. The most beneficial operation of the Missouri River Basin Pick-Sloan plan is currently the subject of the Master Control Manual review and update by the Corps of Engineers. To the extent, that the replacement water supplies are being used to generate hydropower, the tribes should receive the revenue or the power produced by the replacement water. In this section of the statement, a partial history of encroachment on Indian water supplies requiring replacement water (or equivalent power) from the Pick-Sloan project is presented.

6.1 Before the 1994 Flood Control Act and Pick-Sloan Plan.

Planning for major water development projects in the Missouri River basin was underway prior to and immediately following the establishment of the Reclamation Service (predecessor of the Bureau of Reclamation) in 1902. Early efforts were concentrated on the Milk and Saint Mary Rivers involving the Fort Belknap and Blackfeet Tribes, respectively. By 1905, concurrent with the prosecution of the *Winters* case on Fort Belknap, the Reclamation Service has devised a plan for the irrigation of the Milk River Valley. The plan was developed by engineer, Cyrus C. Babb, namesake of the community of Babb, Montana, located on the Blackfeet Indian Reservation.

The Milk River Plan was intended to irrigate 250,000 acres, including 32,995 acres on the Fort Belknap Indian Reservation. The Reclamation Service, however, did not perceive the Tribe or its membership as the irrigators of land on Fort Belknap. As stated in the third annual report of the Reclamation Service:

> *"During 1904, a canal has been surveyed from the South side of Milk River, heading about three miles southeast of Chinook. It continues eastward through the Fort Belknap Indian Reservation, and will be 57 miles long. It has a most excellent location, with very little sidehill construction and only a few flume crossings. The total area covered is 48,000 acres, of which 15,000 acres are west of the Reservation and the balance on the Reservation itself.* ***In order to make this latter area available the opening of a portion of the Indian Reservation would be necessary."*** (Third Annual Report of the Reclamation Service, pg. 301) (Emphasis supplied).

The *Winters* decision in 1906 (followed by the U.S. Supreme Court decision in 1908) confirmed the reserved rights of the Fort Belknap Gros Ventre and Assinniboine Tribes. The decision enjoined Henry Winters and others from interfering with the flows of the Milk River that would otherwise diminish the 5,000 miners inches (125 cubic feet per second) needed for irrigation of approximately 10,000 acres on the Fort Belknap Indian Reservation. The project, undertaken by the Indians on Fort Belknap, had only been developed to a level of 10,000 acres, as distinguished from the 33,000 acres that had been identified by the Reclamation Service with the *necessity* that the area be open to white settlement.

The project on Fort Belknap, developed by the Tribes as of 1906, was never enlarged to encompass the 33,000 acres contemplated by the Reclamation Service. Rather, the Reclamation Service built a non-Indian project, both upstream and downstream from the Fort Belknap Indian Reservation, to such extent that all of the natural water supply of the Milk River was exhausted. There was no additional water supply to irrigate the additional lands on Fort Belknap, because the full water supply of the Milk River had been committed to non-Indian projects by the Reclamation Service.

In the Ahtanum decision on the Yakima Indian Reservation in 1956, the 9th Circuit Court of Appeals applied the principles of the *Winters* decision and found that *"...the Indians were awarded the paramount right regardless of the quantity remaining for use of white settlers."* The court further found that *"...if the amount awarded the United States for the benefit of the Indians in the Winters case equaled the entire flow of the Milk River, the decree would have been no different."* (Appendix A)

As shown above, the Federal Circuit Court had an entirely different concept of the *Winters* doctrine than the Federal Reclamation Service. While in principle, the Fort Belknap Tribes were entitled to use all of Milk River, the Reclamation Service committed the entire flow of the Milk River to non-Indian projects, and the Fort Belknap Tribes were unable to develop to the level that Reclamation Service had originally contemplated when it proposed that the Fort Belknap Indian Reservation be opened to white settlement for purposes of irrigation reclamation.

During these early years (circa 1905), Cyrus C. Babb, recognizing that the flow of the Milk River was inadequate to irrigate the full 250,000 acres planned by the Reclamation Service, sought the waters of the St. Mary River to supplement the Milk River. The St. Mary River rises on the Blackfeet Indian Reservation and flows northward into Canada where it joins the Bow River to form the South Saskatchewan River. These streams flow into Hudson Bay. In 1905 the Reclamation Service considered three options as follows:

(1) Diversion of the St. Mary to the North Fork Milk River where it would be allowed to run through Canada to the Lower Milk River Valley.

(2) Utilize the waters on the eastern section of the Blackfeet Indian Reservation and on lands immediately east of the Reservation.

(3) Convey the St. Mary water across both the North and South Forks of the Milk River to Cutbank drainage allowing it to flow down Marias River 100 miles or more to the Big Sandy area between the Missouri and Milk Rivers.

Cyrus Babb found that the most feasible project was the first: diversion of the St. Mary River to the North Fork Milk River for use in the Lower Milk River Valley. Babb, however, also found that the second plan could be carried out with feasibility. He found that the eastern part of the Blackfeet Indian Reservation and the country immediately east of it was well adapted to irrigation. He identified a level tract of good soil comprising 100,000 acres with no available water supply immediately near it that could be served from the St. Mary River.

Two points need to be made with regard to this early planning of the Reclamation Service. First, when the *Winters* case was being prosecuted and following all decisions in the *Winters* case, the Reclamation Service was committing all of the waters of the Milk River, except those awarded to Fort Belknap in *Winters*, to non-Indian reclamation projects. The Reclamation Service was likewise committing all of the Blackfeet *Winters* waters of the St. Mary River to purposes outside the Blackfeet Indian Reservation, namely a supplemental supply in the Milk River Valley for non-Indians. Second, the United States entered into the International Boundary Waters Treaty with Canada for the specific purpose of dividing the waters of the Milk and St. Mary Rivers equally between the two countries. This Treaty was adopted in 1909. No mention or resolution of the Blackfeet and Fort Belknap *Winters* doctrine rights in the St. Mary and Milk Rivers was addressed in the Treaty with Canada. Nor were encroachment on the reserved rights of the Peigan and Blood Tribes in Canada addressed. Each of these Tribes had treaties with their respective governments that dated from 1851 through 1877. The Indian treaties were ignored.

The effect of the 1909 Boundary Waters Treaty and the development of the Milk and St. Mary Rivers by the Reclamation Service was to limit the development of water by the Blackfeet and Fort Belknap Tribes. On Fort Belknap, the Tribes were limited to 10,000 acres, the first stage of their larger project which was the subject of the *Winters* case. Reclamation abandoned all irrigation on the Blackfeet Indian Reservation from the St. Mary's River and diverted the stream to the non-Indian Federal Reclamation Project in the Milk River Valley.

The *Winters* doctrine on the one hand provided that the Blackfeet had rights to irrigate its portion of the 100,000 acres identified by Cyrus Babb as irrigable from the St. Mary's River, and the Fort Belknap Tribes had a right to irrigate as many as 33,000 acres below the canal crossing the Fort Belknap Indian Reservation with heading to the east of Chinook, Montana. On the other hand, the Reclamation Service prohibited the development of those acres by committing all of the available water supplies to non-Indian projects. As a practical matter, the Blackfeet and Fort Belknap tribes in 1994 are being forced to negotiate with the State of Montana for the reason it is highly improbable that an adjudication process in the State of Montana would cause the discontinuation of water diversion by non-Indians in the Milk River Valley to permit Blackfeet or Fort Belknap to exercise their rights, which were diverted away from them by the Reclamation Service (circa 1905), despite findings by the Reclamation Service at the time that the use of water on the Indian lands was feasible.

The aggressiveness of the Reclamation Service to develop projects for non-Indians that relied on Indian reserved water was not limited to the Milk and St. Mary Rivers. Prior to the 1944 Flood Control Act, the Belle Fourche Project in the headwaters of the Cheyenne River above the Pine Ridge and Cheyenne River Indian Reservations was well advanced.

By 1940, there were 462,500 acres irrigated in the Bighorn Basin of Montana and Wyoming, relying substantially on *Winters* doctrine water rights of the Arapaho, Shoshone, and Crow Tribes. The Shoshone Project, one of the oldest developments of the Bureau of Reclamation, provided water to the Garland Division in 1908. The Riverton project was begun in 1920 by the Bureau of Reclamation. By 1940, it irrigated approximately 35,000 acres. Bull Lake and Pilot Butte Reservoirs provided storage capacity of 182,000 acre feet. A total of about 117,000 acres were irrigated in 1940 in the central Bighorn Basin. By 1940, four divisions of the Shoshone Project, including a reservoir, had been developed to irrigate 58,900 acres.

By 1940, the dependable water supply of the Tongue River below Tongue River Reservoir in Montana had been fully developed primarily for non-Indian irrigation without consideration of the rights of the Northern Cheyenne.

6.2 After 1994 Flood Control Act and Pick-Sloan Plan

As previously described, the water supplies needed to fulfill the *Winters* doctrine rights of the Blackfeet, Fort Belknap, Wind River, Crow, Arapaho, Shoshone, and Northern Cheyenne Tribes had been largely committed to the Milk River, Bighorn, and Tongue River projects. Similarly, Big Sandy, Boxelder, and Beaver Creeks of the Rocky Boys Indian Reservation, which discharge to the Milk River, were relied upon as tributary inflow to the Milk River Federal Reclamation Project.

Irrigation projects were developed before 1944 on the Indian reservations in Montana, including Blackfeet, Rocky Boys, Fort Peck, Crow, and Wind River. However, much of the land and irrigation (from 80-90%) was non-Indian on lands within the reservations. The exception was Fort Belknap where the Tribes developed the irrigation project that required injunction against Henry Winters and others on the Milk River system. Here the land was owned predominantly by Tribal members.

In North and South Dakota there was a considerable taking of Indian land for building the mainstem dams of the Pick-Sloan Plan. All of the mainstem reservoirs in North and South Dakota: Lake Sakakawea, Lake Oahe, Lake Sharpe, Lake Francis Case, and Lewis and Clark Lake, are bordered, in part, by Indian reservations. The affected reservations from upstream to downstream include Fort Berthold, Standing Rock, Cheyenne River, Lower Brule, Crow Creek, Yankton, and Santee.[2]

Irrigation development and participation in the **electrical generation** by the Tribes from the Pick-Sloan project was promised but never realized. The Bureau of Indian Affairs examined the Pick-Sloan Plan in April 1944 and corresponded with the commissioner of the Bureau of Reclamation as follows:

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[2] An 1868 Treaty had established the east bank of the Missouri River as the eastern boundary of the Great Sioux Reservation. The division of the Great Sioux Reservation into nine smaller parts by an 1889 act of Congress, including the above named reservations, was a pre-requisite to statehood by South Dakota. The Great Sioux Reservation had previously occupied all of present-day South Dakota west of east high Bank of the Missouri River. When gold was found in the Black Hills in the 1870's, the United States lost interest in preserving the permanency of the Great Sioux Reservation promised by the Treaty of 1868:

> "*...the United States agrees that the following District of Country...shall be...set apart for the absolute and undisturbed use and occupation of the Indians herein named....*" (1868 Treaty, Kappler, 1904, pg. 998).

"...In so far as the Indian irrigation and power interests are concerned, the report seems to give them adequate consideration." (April 26, 1944 letter from William Zimmerman to Harry W. Bashore).

The *Summary Forward* of the Pick-Sloan Plan provided that all planning would be coordinated, and such planning necessarily required consideration of the Tribes' prior and paramount rights to the use of water and the need for *pumping* and *preference* power:

> *"Present and future plans of State agencies and various Government agencies such as the Indian Service, the Fish and Wildlife Service, the National Park Service, and the Bureau of Reclamation, as well as the War Department, the Department of Agriculture, and the Federal Power Commission should be coordinated, in order to avoid the waste incident to conflicting plans and duplication of effort, and in order to gain the advantages of large-scale, coherent works and operations."* (Senate Document 191, pg. 18).

But no such coordination with respect to the Tribes was undertaken. Indian lands were taken for the construction of the dams and reservoirs needed for the Pick-Sloan Plan. The 9-foot navigation channel below Sioux City required taking of lands of the Omahas and Winnebagos.

The Bureau of Reclamation and Corps of Engineers proceeded to develop non-Indian projects above the Indian reservations on the tributary streams. On the tributary streams there were plans for Indian development, none of which materialized for the reason that the Bureau of Reclamation implemented or participated in projects that fully monopolized the dependable water supplies of the tributary streams and physically foreclosed the opportunity for Indian developments that had been identified in the Pick-Sloan Plan, irrespective of the Tribes' prior and superior water rights. That the United States, acting through the Department of the Interior, was aware of the prior and superior rights of the Tribes is without question, and that they proceeded, nevertheless, to develop non-Indian projects is also without question.

On the Standing Rock Indian Reservation, the Pick-Sloan Plan contemplated the development of the Grand River:

> *"Although 66,680 acres in the Grand River basin in South Dakota was found to be adapted to irrigation, full regulation of the water supply will permit development of only 28,500 acres, which will be accomplished by creating the Shadehill Reservoir of a capacity of 134,000 acre-feet, and by serving 13,000 acres by a gravity canal diverting from the river at the reservoir. Return flow from land irrigated with water from this reservoir will be picked up in the Blue Horse Reservoir some 28 miles downstream, where a capacity of 50,000 acre-feet will be provided to serve 16,500 acres of land and 46 smaller pumping units, ranging from 85-1,285 acres each.* ***Much of the land below the Blue Horse Reservoir is within the Standing Rock Indian Reservation, and is owned by Indians, while practically all of the land above the Blue Horse Reservoir is in private white ownership."*** (Senate Document 191, pg. 76). (Emphasis supplied).

The Milk River pattern was followed with regard to Standing Rock. The Bureau of Reclamation developed the Shadehill irrigation project, but no Indian land was ever developed within the Standing Rock Indian Reservation. In connection with the Shadehill project, the Indian Service wrote as follows at the time of the implementation:

"Under the authorities, the waters involved in the cases arising from interference with waters on, bounding, or flowing through Indian reservations are not open to appropriation by individuals to the detriment of the Indian wards of the United States who may require such for agricultural and domestic uses, even though there is no present great water use because of the failure of the trustee, the United States, to foster or permit irrigation on or for the Indian lands... The Indian lands on the Standing Rock Reservation, State of South Dakota, enjoy prior reserved rights for the use of the waters of the Grand River and its tributaries for (1) the lands in Tribal ownership and (2) allotted lands. This property right was retained by the provisions of the Treaty of April 29, 1868..., subsequent acts of Congress and in proclamations of the President of the United States which further defined the area of the Standing Rock Sioux Tribe..." (Walter J. Turnbull, February 10, 1949, U.S. Bureau of Indian Affairs, Billings, MT).

Following the building at Shadehill, the U.S. Army Corps of Engineers built the Bowman-Haley project with a capacity of 93,000 acre-feet on the North Fork of the Grand River (1966). The project followed 60 years of investigation by the Bureau of Reclamation and Corps of Engineers and was intended to irrigate 2,200 to 8,000 non-Indian acres. This project further encroached upon the physical capability of the Standing Rock Sioux Tribe to develop irrigation within the Reservation, irrespective of the prior and superior water rights of the Tribe. Today the quantity and quality of the remaining water supply of the Grand River prohibits significant development by Standing Rock. Restoration of this stream is necessary if the Tribe is to exercise the full extent of its Grand River *Winters* doctrine water rights.

The Pine Ridge Indian Reservation in the southwest corner of South Dakota relies upon the White and Cheyenne Rivers as sources of *Winters* doctrine rights to the use of water. The Whitney Irrigation project has dominated the flows of the White River since the 1920's. The Bureau of Reclamation wrote as follows in 1968:

"The Whitney Irrigation project, constructed in 1923 near Crawford, Nebraska, has an off-stream reservoir which initially had a capacity of 10,960 acre-feet for irrigation of about 10,000 acres....There are currently 37 direct-flow water rights on file for the White River in Nebraska, which total 115.1 cubic feet per second (c.f.s.) for approximately 8,060 acres of land....Stream flows of the White River have been over-appropriated for many years and are sufficient to satisfy water rights in Nebraska and South Dakota only during flood and high flow periods...." (U.S. Bureau of Reclamation, Missouri-Oahe projects office, 1968).

The Pick-Sloan Plan acknowledged the development of the non-Indian Whitney Irrigation project on the White River in Nebraska and proposed a plan that would restore a dependable supply of water for the Pine Ridge Indian Reservation, but that plan and subsequent plans proposed by the Bureau of Reclamation were never implemented. The Pick-Sloan Plan provided as follows:

> *"White River rises in low hills of western Nebraska and flows northeastward into South Dakota, to a confluence with the Missouri about 15 miles downstream from Chamberlain, S.Dak. All of the water resources of the White River arising in Nebraska have already been utilized by the Whitney Irrigation District, an area of some 10,000 acres, served by an inland reservoir of 15,000 acre-foot capacity. A supply canal for this reservoir diverts a spring flow in the White River, which is markedly uniform throughout the year. In South Dakota, the remaining watershed produces an exceedingly erratic run-off, with high discharges from summer rainstorms, which fall on the prairie area and on a large area of shale badlands, that produce quick and heavily silt-laden run-off. A reservoir of 70,000 acre-foot capacity at the Rocky Ford site [Pine Ridge Indian Reservation] about 25 miles upstream from the town of Interior, will furnish an adequate water supply for 42,000 acres of small units, scattered from the reservoir site to the mouth of the river, all of which must be served by pumps. Power to operate the pumps will be imported into the basin. The available water supply will serve less than half of the area of land in the basin which is adapted to irrigation."* (Senate Document 191, pg. 77).

Thus, it was well known by the Bureau of Reclamation and Corps of Engineers, as they developed the Pick-Sloan Plan, that the prior and superior water rights of the Oglala Sioux Tribe of the Pine Ridge Indian Reservation were adversely impacted by the Whitney Irrigation Project and that a physical solution, in part, was possible by building the Rocky Ford Dam and irrigating Indian lands within the Pine Ridge Indian Reservation.

Subsequent investigations by the Bureau of Reclamation identified the Slim Butte Reservoir as an alternate storage site. Reclamation described that project as compatible with the present level of water resources development in Nebraska, immediately south of the boundary of the Pine Ridge Indian Reservation. As late as 1977, the Bureau of Reclamation acknowledged the prior and superior rights of the Oglala Sioux Tribe but proceeded nevertheless to assist the Whitney Irrigation Project with rehabilitation and upgrading of its facilities:

> *"On September 13, 1973, the regional loan engineer and chief, water and land of the Missouri-Oahe project office, met with members of the District, board members, and District's Attorney to discuss the potential project. Representatives of the Fish & Wildlife Service, Soil Conservation Service, and Nebraska Department of Water Resources participated in the meeting. Based on discussions with the Bureau, the District subsequently requested the Bureau for an opinion on the water rights of the Whitney Irrigation District, particularly with respect to the downstream Indian reservation.* (Bureau of Reclamation, 1977).

"Please be advised that we have examined the report [of Whitney Irrigation District] and believe it to be legally sufficient. The sponsor is an irrigation district organized, qualified, and under State law to, among other things, enter into contracts with the United States, acquire lands and interest in lands and hold water rights." (Bureau of Reclamation, 1977).

The Governor of Nebraska, on January 10, 1977, confirmed that the State of Nebraska recognized the water rights of the Whitney Irrigation District but remained silent on resolution of the conflict with Oglala Sioux water rights:

"The application for a Small Reclamation Project Loan submitted by the Whitney Irrigation District appears to be financially feasible. In addition, water rights claimed by the applicant are adequate and valid. Therefore, I would recommend that the loan application of the Whitney Irrigation District be forwarded to the Secretary of the Interior for consideration." (Exxon 1977).

It is clear from the foregoing that the United States knew that the Whitney Irrigation Project dominated the dependable water supplies of the White River, and that additional storage facilities were needed (due to the Whitney Irrigation Project) on the Pine Ridge Indian Reservation to accomplish irrigation using the prior and superior water rights of the Oglala Sioux Tribe. Notwithstanding, the United States did not proceed to resolve the water rights conflict between the inferior claimants of the Whitney Irrigation District and the Oglala Sioux Tribe. Reclamation assisted the District as recently as 1977 in rehabilitation of its project. Both the Oglala Sioux and Rosebud Sioux Tribes are adversely affected by the Whitney Irrigation Project and the actions and inactions by the United States respecting the White River.

Plans for the future development of the Cheyenne River in the Pick-Sloan Plan were as follows:

"...Cheyenne River is the largest tributary of the Missouri in South Dakota....One other reclamation project has been authorized, namely the Angostura project in the southwest part of the Cheyenne River watershed, whereby the construction of Angostura Reservoir with a capacity of 160,000 acre-feet water can be supplied by gravity to a 16,000 acre project in the vicinity of Hot Springs, S. Dak., and to 25,300 acres in 49 scattered pumping units along the lower reaches of the River..." (Senate Document 191, pg. 76).

The Cheyenne River is the source of *Winters* doctrine rights to the use of water of the Oglala Sioux of the Pine Ridge Indian Reservation and the Cheyenne River Sioux of the Cheyenne River Indian Reservation. Despite the potential announced in the Pick-Sloan Plan for development of part of the project on the Pine Ridge and Cheyenne River reservations, the Angostura project was constructed by the Pick-Sloan Plan, exclusively on non-Indian Lands, upstream from both the Pine Ridge and Cheyenne River reservations.

For the past 90 years, there has been a consistent pattern of developing Bureau of Reclamation projects in the Missouri River basin that rely upon Indian land and water. The physical supplies available to the Tribes (both quantity and quality) have been diminished to the point that they are unusable by the Tribes. The Secretaries of the Departments of Interior and Army were constantly aware of the prior and superior rights of the Tribes but, in conjunction with state water resource agencies, assisted in development of water projects with inferior water rights.

7.0 Unused *Winters* Doctrine Rights of the Missouri Basin Tribes Generate Hydropower Marketed by Western: Tribal Contribution to National Economy

In addition to the streams mentioned in the previous section where replacement waters are needed until quantity and quality can be restored there are other streams and aquifers with adequate quantity and quality for Indian development, but funds have never been available for such development. On these streams there is a federal and state effort to diminish our *Winters* doctrine reserved rights by adjudication in state courts or negotiated settlement. Both processes degrade Indian property and the spirit of our people. (Sections A.2, A.3 and A.4).

There is opportunity for Congress to develop a solution that would permit the Tribes to protect our *Winters* doctrine rights while permitting our participation in Western power resources. The following are conceptual elements of a solution:

- Enact legislation directing a part of the benefits of Missouri River Pick-Sloan (hydropower, navigation, environmental enhancement, endangered species protection) to the Indian tribes on an annual basis in proportion to *Winters* doctrine rights determined by the Tribes.

- To the extent a tribe develops water supplies in the future, reduce the tribe's annual benefits derived from Pick-Sloan by the amount of water used in relation to the amount claimed.

- Prohibit the states from *reserving*[3] future quantities of water that, when developed, would further reduce the quantities of water available in the streams and aquifers of the Missouri River Basin Indian reservations.

Our water rights are being destroyed by state court adjudication and forced negotiation under the threat of state court adjudication. State court adjudications are the most barbaric acts committed against the Indian tribes during the 20th century, and negotiations under the threat of adjudication are a disgrace to the nation. Future generations will harshly judge the techniques used today to destroy Indian water rights.

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[3]States, such as Montana, seek to extinguish Indian *reserved* water rights and create a new doctrine of state *reserved* water rights.

These techniques include criteria developed by the United States Departments of Justice and Interior that place unworkable barriers on the tribes in state-court, McCarran Amendment adjudications. Cyrus Babb and other Reclamation engineers throughout the history of Missouri River basin development were never faced with the burdens of proof imposed by criteria developed by the Departments of Justice and Interior and used in state adjudication proceedings, such as the *Wind River* case in Wyoming. Because Indian water rights cannot survive decisions such as those resulting from the *Wind River* case in Wyoming, the tribes are compelled to seek some other course. In the Missouri River Basin we must turn to Congress and the Pick-Sloan Project for a solution.

It is possible to distinguish between the water supplies stored and released from the reservoirs of Missouri River Basin Pick-Sloan that are required to fulfill the *Winters* doctrine claims of the tribes and the remaining water supplies that are stored and released. The waters of the Missouri River needed to fulfill the claims of the Missouri River Basin tribes are the subject of the foregoing analysis.

The Corps of Engineers in its Master Manual Review and Update presents average annual NED (National Economic Development) benefits for the 93-year simulation (1898 through 1990) for the *current* Master Control Manual as follows:

Flood Control	$0.041 Billion
Hydropower	.655 Billion
Water Supply	.546 Billion
Recreation	.048 Billion
Navigation	.016 Billion
TOTAL ANNUAL	$1.277 Billion

Of the detailed analysis of seven alternatives for *future* operation of the Missouri River, the best of the seven would increase average annual NED (National Economic Development) benefits to $1.284 billion.

Clearly, hydropower has the greatest contribution to the economic value of the Missouri River basin system. The reduced cost of construction, operation and maintenance of facilities to supply municipal, rural and industrial water (defined by the Corps as the Water Supply benefit) is the next largest contribution to benefits. Navigation benefits are the least of the principle purposes of the project.

The Coalition seeks to distinguish between the NED benefits produced by Indian water rights and those produced by remaining waters. We assert that activities by the United States have prevented the Tribes from exercising their *Winters* doctrine reserved water rights on the mainstem and tributaries to the Missouri River. If non-Indians are to continue dominating the water supplies of the Missouri River and tributaries, irrespective of the prior and paramount rights of the Indian tribes, the only solution for the Tribes is a physical solution involving that portion of the NED benefits that are generated with the Tribes' unused water rights.

The principle of Indian participation briefly stated above has been addressed by the Federal Power Commission, predecessor of FERC, in assessing the value of renting Indian property utilized by a private utility in the production of hydropower. There is no attempt here to address the law on this matter. It is important, however, to address relative contributions of property of respective owners in the production of a marketable commodity and the share that the owners should have in the income or other benefit derived from the contribution of property, in this case water rights of the tribes that have been denied use. The Federal Power Commission and the 9th Circuit Court of Appeals used the following rationale:

> *The Commission fixed the readjusted annual rental charges to be paid by the company to the Tribes...the basic criteria are those of...the 1930 license, which calls for:*
>
> > *"...Reasonable charges fixed...upon the commercial value of the Tribal lands involved, for the most profitable purpose for which suitable, including power development."*
>
> *Thus, it was the task of the Commission, and this is not disputed, to determine the commercial value of the lands to the company for the most profitable purpose for which the lands are suitable. And there is no dispute that the most profitable purpose to which the Tribal lands could be devoted was the development of power.* (Montana Power Company v. Federal Power Commission, 459 FED 2nd 863, 1972 at pg. 869).

In the case of the Missouri River basin, the property used by the United States, in part, to operate Pick-Sloan is the *Winters* doctrine rights to the use of water of the Tribes. Our rights are undeveloped by us for the reasons previously stated: commitment of water to non-Indians, commitment of water to Pick-Sloan and absence of financing for Indian projects. Because our rights have not been taken, however, they are currently utilized in the creation of National Economic Development Benefits by the United States and others. The United States is the owner of facilities that produce Pick-Sloan benefits; and the United States and the Tribes contribute property, namely water, for the production of those benefits. The 9th Circuit Court of Appeals arrived at a rule for sharing between the Tribes and the private utility in the Federal Power Commission case presented above:

> *"The Commission then proceeded to arrive at the sharing formula...in two steps. First, the Commission divided the units of production on the basis of 50% for development and 50% for ownership. Then the Commission again divided the ownership shares so that the water power generated refracted the land interest."* (459 FED 2nd, 863, 1972 at pg. 876).

There is an established rationale for the United States and the Tribes to share in the benefits of the Missouri River Basin Pick-Sloan Plan program. If the United States were to receive 50% of the benefits for its ownership and development of the facilities and the Tribes were to receive a refracted interest in the remaining 50% of the benefits for the ownership of part of the water supply, (for example, 30% of the water supply) then the United States (according to the rationale presented above) should provide 15% (30% of 50%) of the NED benefits annually to be divided among the Tribes in proportion to their contribution of water.

The foregoing is illustrative and by way of example only. The point being made is that it is possible to distinguish between the contributions by the Tribes to the production of NED benefits and the contribution by the United States. Contributions of property rights are not limited to water. Tribes on the mainstem of the Missouri River have contributed more than water supply. The contribution of land by some of the Tribes in the development of the mainstem reservoirs and the navigation channel is reviewed in Section 8.

The United States has chosen to sell the electricity produced by the mainstem dams at the cost of producing the electricity. However, the value of the power is substantially greater than its sale price. Moreover, the United States has chosen not to assess charges for navigation that reflect the savings by owners of commodities that chose lower cost barge transport over rail or other means of transportation. The United States does not charge for the use of the dams and releases from storage, even though the cost of diversion by the end user is less than would be incurred otherwise because the storage facilities reduce the pumping lift and the length of intake required among other things. Even though the United States receives less in cash receipts than the full value of the output of Missouri River Pick-Sloan, the United States nevertheless receives sufficient revenues to repay the costs of the dams, the hydropower facilities, and the electrical transmission lines that convey federal power to the customers of the Western Area Power Administration. Electricity is the principle Pick-Sloan product for the solution presented here just as it is currently used to repay other project costs.

The United States has a duty of a trustee to perform for American Indians. The fiduciary relationship resembles a guardianship or a trust responsibility. In principle, responsibilities of the United States have been expressed as follows:

> *"The United States Government acts as a legal trustee for the land and water rights of the American Indians and has a legal obligation to advance the interests of the beneficiaries of the trust without reservation and with the highest degree of diligence and skill."* (Former President Nixon, July 8, 1970, H.R. Doc. No. 91-363, 91st Congress, Second Session (1970), as quoted in Reid Peyton Chambers, Judicial Enforcement of the Federal Trust Responsibilities to Indians, Stanford Law Review, Volume 27, p. 1215, May 1975).

The trust responsibility can be tested in the U.S. Court of Claims to determine the amount of damages stemming from the actions of the United States:

> *"The Court of claims shall have jurisdiction to render judgment upon any claim against the United States founded either upon the Constitution, or any Act of Congress, or any regulation of an executive department, or upon any express or implied contract with the United States, or for liquidated or unliquidated damages in cases not...in tort."* (Tucker Act as quoted in 463 US 206, 1982, *United States v. Mitchell II*, P. 212).

Declaratory and injunctive relief are also available:

"A more expansive reading of the trust relationship, however, would suggest that the preservation of the trust corpus in a particular forum --- land and natural resources, instead of money -- is itself a critical value." (Chambers, 1975 p. 1236).

The nature of the United Sates responsibilities for management of forest and other resources on Indian Reservations has been addressed by the U.S. Supreme Court:

"Referring to the relationship between Indians and the Government as 'sacred trust', Representative Howard stated that 'the failure of the governmental guardian to conserve the Indians' land and assets and the consequent loss of income or earning power, has been the principle cause of the present plight of the average Indian". (78 Cong. Rec., at 11726, as quoted in 463 US 206).

A federal responsibility exists to protect forest resources addressed in *Mitchell II* and to protect *Winters* doctrine water rights addressed in the *Ahtanum* decision.

Scholars on the subject further address the responsibilities of the United States with regard to the *Winters* doctrine water rights of the Indian Tribes:

"The underlying premise of the Winters doctrine is the government's promise implicit in the establishment of reservations, to make them livable and to enable Indians to become self-sustaining. Yet most Indian tribes are not utilizing their full legal entitlement of reserved water rights. Only a small portion of the irrigable lands belonging to Indians or Indian tribes is being cultivated or is included within irrigation projects. For political and institutional reasons, the United States has failed to secure, protect and develop adequate water supplies for many Indian tribes...

One reason for the government's failure to assert, protect and develop Indian water rights can be traced to its conflicts of interest. The United States Congress and the Interior and Justice Departments have responsibility to advance, at the same time, the national interest in land and water use as well as the interest of Indians for whom the government acts as trustee... Even if direct governmental conflicts are not involved, the political problems associated with enforcement of Indian water rights have often interfered with the governments performance of its trust obligations.

The legal right to water does not automatically bring with it the capital investment necessary to realize its economic benefits. Irrigation systems and other water resource projects often require substantial investments, and the Congress has tended to give a higher priority to projects that benefit non-Indians. Consequently, most Indian tribes have not been able to utilize their full entitlements of water." (Felix S. Cohen's Handbook of Federal Indian Law, 1982, Edition, pp. 596 *et seq*).

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In Public Law 102-575, Congress established the duty of the United States to protect the water resources of the Indian tribes.

The concept presented here, subject to acceptability by each of the tribes and subject to details not presented here, formulate the basis for an equitable, as distinguished from the present uncivilized process, for protection of *Winters* doctrine claims of the Missouri River Basin tribes. There is a compelling need for the Western Area Power Administration to reserve part of the federal power produced by Missouri River Basin Pick-Sloan to address this concept. The Coalition is prepared to offer more specific recommendations on means for Western to address this issue.

8.0 All Costs of Pick-Sloan Are Not Covered by Western's Power Revenues

The following were the lands taken to construct the mainstem reservoirs between Gavins Point and Garrison dams:

Reservation	Reservoir	Acres Taken
Fort Berthold	Garrison	154,912
Standing Rock	Oahe	55,994
Cheyenne River	Oahe	99,548
Lower Brule	Big Bend	14,958
Lower Brule	Fort Randall	7,997
Crow Creek	Big Bend	6,416
Crow Creek	Fort Randall	9,149
Santee	Gavins Point	593
Total		349,566

Congressional acts and other arrangements to take the lands of the Tribes were dated from 1949 through 1962. A total of 349,566 acres or 23% of the 1,499,759 project acres for these dams and reservoirs were taken from Tribes. Additional research is needed to determine the acreage and number of miles of artificial navigation channel constructed across the Omaha and Winnebago Indian Reservations. The value of the lands taken from these tribes for purposes of the dams and reservoirs alone is conservatively estimated at no less than $750 million, part of which could be furnished by federal power and part by appropriations. Western's power revenues are intended by Congress to cover the costs of all Pick-Sloan facilities, but they do not cover the fair value of Indian lands.

APPENDIX A

MCCARRAN AMENDMENT CASES AND FORCED NEGOTIATION ARE DESTROYING *WINTERS* DOCTRINE WATER RIGHTS

A.1 Nature of the *Winters* Doctrine

In British law announced in the Proclamation of 1763 by King George III was a recognition of title to the land and resources reserved by the American Indians, including water. The *Winters* doctrine in 1908 announced the concept of the right of the Indian tribes to use water reserved by them, but the genesis of those rights in European, British and North American law can be traced backward through the centuries. The following is not a legal analysis of the *Winters* doctrine, but is a presentation of the basic concepts.

By 1832 the United States Supreme Court recognized the property rights of Indians in the classical case of *Worcester v. the State of Georgia:*

> *"America, separated from Europe by a wide ocean, was inhabited by a distinct people, divided into separate nations, independent of each other and of the rest of the world, having institutions of their own and governing themselves by their own laws. It is difficult to comprehend the proposition, that the inhabitants of either quarter of the globe could have rightful original claims of dominion over the inhabitants of the other, or over the lands they occupied; or that the discovery of either by the other should give the discoverer rights in the country discovered, which annulled the pre-existing rights of its ancient possessors."* (6 P 515, p. 543)

> *"... This principle, suggested by the actual state of things was 'that discovery gave title to the government by whose subjects or by whose authority it was made, against all other European governments which title might be consummated by possession' 8 Wheat. 573.* (6 P 515, p. 543-44)

> *"... This principle, acknowledged by all Europeans, because it was the interest of all to acknowledge it, gave to the nation making the discovery, as its inevitable consequence, the sole right of acquiring the soil and making settlements on it. It was an exclusive principle which shut out the right of competition among those who had agreed to it; <u>not one which could annul the previous rights of those who had not agreed to it.</u> It regulated the right given by discovery among the European discoverers; but could not affect the rights of those already in possession, either as aboriginal occupants, or as occupants by virtue of a discovery made before the memory of man. It gave the exclusive right to purchase, but did not found that right on the denial of the right of the possessor to sell."* (6 P 515, p. 544) (Emphasis supplied)

"... This soil was occupied by numerous and warlike nations, equally willing and able to defend their possessions. The extravagant and absurd idea, that the feeble settlements made on the sea-coast, or the companies under whom they were made, acquired legitimate power by them to govern the people, or occupy the lands from sea to sea, did not enter the mind of any man. They were well understood to convey the title which, according to the common law of European sovereigns respecting America, they might rightfully convey, and no more. This was the exclusive right of purchasing such lands as the natives were willing to sell. The Crown could not be understood to grant what the Crown did not effect to claim; nor was it so understood." (6 P 515, p. 544-545) (Emphasis supplied)

The principles in the case of *Worcester v. Georgia* are similar in concept to the principles announced by the U. S. Supreme Court three quarters of a century later relating to the Yakima Indian Nation in the case of *United States v. Winans* (198 U.S. 371). Title of the Indians in their property rights was fully acknowledged.

"The right to resort to the fishing places in controversy was a part of larger rights possessed by the Indians, upon the exercise of which there was not a shadow of impediment, and which were not less necessary to the existence of the Indians than the atmosphere they breathed. New conditions came into existence, to which those rights had to be accommodated. Only a limitation of them, however, was necessary and intended, not a taking away. In other words, the Treaty was not a grant of rights to the Indians, but a grant of rights from them - a reservation of those not granted." (Emphasis supplied).

Based on fact that the Indians were occupying smaller and smaller reservations from within their former lands, the Supreme Court case of *Henry Winters v. United States* (207 US 564) found that reservation of water for the purpose of changing the Indian people from a "pastoral" to a "civilized" people was implied in the establishment of the Reservation:

"The Reservation was a part of a very much larger tract which the Indians had the right to occupy and use and which was adequate for the habits and wants of a nomadic and uncivilized people. It was the policy of the Government, it was the desire of the Indians, to change those habits and to become a pastoral and civilized people. If they should become such the original tract was too extensive, but a smaller tract would be adequate with a change of conditions. The lands were arid and, without irrigation, were practically valueless."

"... The power of the Government to reserve the waters and exempt them from appropriation under the state laws is not denied and could not be."

"... That the Government did reserve them we have decided, and for a use which would be necessarily continued through years. This was done May 1, 1888, [at Fort Belknap] and it would be extreme to believe that within a year [when the state of Montana was

created] Congress destroyed the Reservation and took from the Indians the consideration of their grant, leaving them a barren waste - took from them the means of continuing their old habits, yet did not leave them the power to change to new ones." (207 U S 574, p. 576-577).

These concepts were further advanced in the case of *Arizona v. California:* (373 U S 546).

"The Master found as a matter of fact and law that when the United States created these reservations or added to them, it reserved not only land but also the use of enough water from the Colorado [River] to irrigate the irrigable portions of the reserved lands. The aggregate quantity of water which the Master held was reserved for all the reservations is about 1,000,000 acre-feet, to be used on around 135,000 irrigable acres of land." (373 U S, 546, page 596.)

"... It is impossible to believe that when Congress created the great Colorado River Indian Reservation and when the Executive Department of this Nation created the other reservations they were unaware that most of the lands were of the desert kind - hot scorching sands - and that water from the river would be essential to the life of the Indian people and to the animals they hunted and the crops they raised." (373 U S 546, pages 598 and 599).

"We follow it [Winters] now and agree that the United States did reserve the water rights for the Indians effective as of the time and agree that the United States did reserve the water rights for the Indians effective as of the time the Indian Reservations were created. This means, as the Master held, that these water rights, having vested before the Act [Boulder Canyon Project Act] became effective on June 25, 1929, are 'present perfected rights' and as such are entitled to priority under the Act. We also agree with the Master's conclusion as to the quantity intended to be reserved. He found that water was intended to satisfy the future as well as present needs of the Indian reservations. ...We have concluded, as did the Master, that the only feasible and fair way by which reserved water for the Reservations can be measured is irrigable acreage. The various acreages of irrigable land which the Master found to be on the different reservations we find to be reasonable." (373 U S 546, pp 600-601)

The case of *United States v. Ahtanum Irrigation District* (236 Fed 2nd 321, 1956) applied the *Worcester - Winans - Winters* concepts on Ahtanum Creek, tributary to the Yakima River and northern boundary of the Yakima Indian Reservation:

"The record here shows that an award of sufficient water to irrigate the lands served by the Ahtanum Indian irrigation project system as contemplated in the year 1915 would take substantially all of the waters of Ahtanum Creek. It does not appear that the waters decreed to the Indians in the Winters case operated to exhaust the entire flow of the Milk River, but, if so, that is merely the consequence of it being a larger stream. As the Winters case, both here and in the Supreme Court, shows, the Indians were awarded the

paramount right regardless of the quantity remaining for the use of white settlers. Our Conrad Inv. Co. Case, supra, held that what the non-Indian appropriators may have is only the excess over and above the amounts reserved for the Indians. It is plain that if the amount awarded the United States for the benefit of the Indians in the Winters Case equaled the entire flow of the Milk River, the decree would have been no different." (236 F. 2nd 321, p. 327) (Emphasis supplied).

A.2 General Nature of Attacks on the *Winters* Doctrine

While the courts in the preceding excerpts stated the basic principles of Indian reserved water rights, the Congress, the Executive, the federal Judiciary at all levels, and the states are practiced in techniques of (1) limiting Indian reserved water rights, (2) suppressing development of those rights, and (3) permitting reliance by federal, state, and private interests on Indian reserved water rights that are not in use.

The Ahtanum Decision was favorable to the Yakimas, as shown at the end of the previous section, but it also addressed the practices of the government to diminish the *Winters* doctrine, a practice that extends to all branches of government (including the courts) and one that has become more focused over the decade of the 1980s:

"*...With an opportunity to study the history of the Winters rule as it has stood now for nearly 50 years, we can readily perceive that the Secretary of the Interior, in acting as he did, improvidently bargained away extremely valuable rights belonging to the Indians. ... Viewing this contract as an improvident disposal of three quarters of that which justly belonged to the Indians, it cannot be said to be out of character with the sort of thing which Congress and the Department of the Interior has been doing throughout the sad history of the Government's dealings with the Indians and Indian tribes. That history largely supports the statement: 'From the very beginnings of this nation, the chief issue around which federal Indian policy has revolved has been, not how to assimilate the Indian nations whose lands we usurped, but how best to transfer Indian lands and resources to non-Indians.'*" (236 Fed 2nd 321, p. 337)

A.3 McCarran Amendment is the Current Vehicle For Disposal of Indian *Winters* Doctrine Water Rights

In 1981, the McCarran Amendment was interpreted by the United States Supreme Court as subjecting Indian rights to the use of water to adjudication in state court systems. The following is the McCarran Amendment:

"*SEC. 208 (a) Consent is given to join the United States as a defendant in any suit (1) for the adjudication of rights to the use of water of a river system or other source, or (2) for the administration of such rights, where it appears that the United States is the owner of or in the process of acquiring water rights by appropriation under State law, by purchase, by exchange or otherwise, and the United States is a necessary party to such suit.*" (43 USC 666, 1952).

The U.S. Supreme Court case in *Arizona v. San Carlos Apache Tribe* permits state courts to determine the measure, nature and extent of Indian water rights. Historically, the states have sought to acquire and administer Indian property and rights thereto:

> *"... we are convinced that, whatever limitation the Enabling Acts or federal policy may have originally placed on State Court jurisdiction over Indian water rights, those limitations were removed by the McCarran Amendment ...the amendment was designed to deal with a general problem arising out of limitations that federal sovereign immunity placed on the ability of the States to adjudicate water rights ..."* (463 US 545, p. 564)

The *San Carlos* decision was unfavorable to the Indian tribes. To arrive at its decision, the U.S. Supreme Court found that Congress had used an appropriations act in 1952 to nullify the agreements between the United States and western territories that permitted statehood by the latter. In those agreements the former territories agreed that Indian matters would remain a federal responsibility. The title of the act was as follows:

> *"Making appropriations for the Departments of State, Justice, Commerce and the Judiciary, for the Fiscal Year Ending June 30, 1953, and For Other Purposes."* (55 STAT 549).

The 1952 Act dealt primarily with salaries and expenses of government personnel. Sections 202 through 208 of the Act deal with general provisions of the Department of Justice:

> *"SEC. 202. Not to exceed $350,000 in the aggregate from the appropriations made in this title for the general administration, general legal activities and United States attorneys and marshals ...*
>
> *SEC. 203. None of the funds appropriated by this title may be used to pay the compensation ...*
>
> *SEC. 204. Sixty per centum of the expenditures for the offices of the United States attorney ...*
>
> *SEC. 205. Appropriations and authorizations made in this title which are available for expenses of attendance at meetings shall be expended ...*
>
> *SEC. 206. Appropriations and authorization made in this title for salaries and expenses shall be available for services ...*
>
> *SEC. 207. None of the funds appropriated by this title may be used to pay the compensation ..."* (66 STAT 549, pp. 559-560).

But in SEC. 208 (a) the McCarran Amendment was presented. It was this section that the U.S. Supreme Court interpreted as the intent of Congress to reverse Indian policy agreed upon before Montana, South Dakota and other western states were granted statehood in the late 1880s. Even SEC. 208 dealt with matters of funding, bringing into question the intent of Congress to waive sovereign immunity in Indian water right adjudications, purportedly granted by SEC. 208 (a). SEC. 208 (d) was this:

> *"None of the funds appropriated by this title may be used in the preparation or prosecution of the suit in the United States District Court for the Southern District of California, Southern Division, by the United States of America against Fallbrook Public Utility District, a public service corporation of the State of California, and others. This title may be cited as the "Department of Justice Appropriations Act, 1953"."* (66 STAT 549, p. 560). (Emphasis supplied).

The U.S. Supreme Court was not unanimous in the McCarran Amendment interpretation of the 1952 Appropriations Act. Justice Stevens concluded that the Court's interpretation went beyond the intent of Congress:

> *"To justify virtual abandonment of Indian water rights claims to the State Courts, the majority relies heavily on Colorado River Water Conversancy District, which in turn discovered an affirmative policy of federal judicial abdication in the McCarran Amendment. I continue to believe that Colorado River read more into that amendment than Congress intended ... Today, however, on the tenuous foundation of a perceived Congressional intent that has never been articulated in statutory language or legislative history, the Court carves out a further exception to the 'virtually unflagging obligation' of Federal courts to exercise their jurisdiction. The Court does not - and cannot - claim that it is faithfully following general principles of law. ... That Amendment is a waiver, not a command. It permits the United States to be joined as a defendant in state water rights adjudication; it does not purport to diminish the United States' right to litigate in a federal forum and it is totally silent on the subject of Indian tribes' rights to litigate anywhere. Yet today the majority somehow concludes that it commands the Federal Courts to defer to State-Court water right proceedings, even when Indian water rights are involved."* (463 US 545, p. 573, et. seq.).

A.4 Western States Are Abusing the Purported McCarran Amendment Grant to Waive Sovereign Immunity In Indian Water Right Adjudication

The McCarran Amendment, an after thought to an appropriations Act in 1952 for the Department of Justice and other Federal agencies, was interpreted by the U.S. Supreme Court (as shown above) as the intent of Congress to remove the limitation on State Court jurisdiction to adjudicate Indian water rights. Since the *San Carlos* decision in 1981 (and the parallel case of *Northern Cheyenne*), the Federal District Courts and the Federal Circuit Court of Appeals have interpreted the case as virtual abandonment of Indian water rights to the State Courts. Both Arizona (San Carlos case) and Montana (Northern Cheyenne case) have initiated general water right adjudications for the purpose of diminishing the *Winters* doctrine rights of the Indian tribes in those states. In Montana, the following process is ongoing:

(1) The State of Montana sued all tribes in the State in a McCarran Amendment proceeding.

(2) The State of Montana established a Reserved Water Rights Compact Commission. The purpose of the Commission is to negotiate the *Winters* doctrine rights of the Montana tribes.

(3) The Department of Interior has adopted a negotiation policy for the settlement of Indian water rights. The U.S. Department of Interior has a negotiation team which works with the Montana Reserved Water Rights Compact Commission and Indian Tribes. Whether Indian Tribes would participate absent McCarran Amendment adjudication is highly questionable.

(4) The Department of Interior makes all necessary funding available to the tribe willing to undertake negotiations. A tribe refusing to negotiate cannot obtain funding to protect and preserve its *Winters* doctrine water rights.

(5) Upon reaching agreement between the State of Montana and an Indian tribe, Congressional staff are assigned to develop legislation in the form of an Indian water rights settlement that may or may not involve authorization of Federal appropriations to develop parts of the amount of Indian water agreed upon between the Tribe and the State or for other purposes.

(6) In the absence of the desire of a Tribe to negotiate, the State of Montana proceeds to prosecute its McCarran Amendment case against the Tribe.

(7) The State of Montana, in a separate process, has reserved water to itself for future purposes based on projected water use by its citizens, despite the fact that the Doctrine of Prior Appropriation requires the use of water by an appropriator, and there can be no reservation of rights by a state for a future purpose, except as diligent completion of a project for beneficial use.

The process (although not the details) in Arizona is basically the same. The process in both Montana and Arizona must be questioned for the reason that the settlement is reached by threat of the State to continue the prosecution of an adjudication against the Indian tribe. Therefore, the Tribe is forced to evaluate the merits of a settlement of its *Winters* doctrine water rights against the merits of a State Court proceeding against the Tribe to establish its *Winters* doctrine water rights.

In the case of settlement, the Indian tribe has a guarantee from the United States that several million or several tens of millions of dollars will be added to the settlement process through Congressional ratification of the settlement and the authorization of Federal appropriations. Thus, the Tribe avoids a hostile State Court forum, arrives at an agreement to diminish its water rights claims and receives Federal funds to meet the needs of an Indian population with income levels well below poverty level. The process is hailed as a success by the States, the Federal agencies and the Congress. In fact, however, the duress under which the Tribes are proceeding will be analyzed harshly by history. Taking of Black Hills from the Great Sioux Reservation, taking of the Little Rockies from Fort Belknap and the taking of Glacier Park from the Blackfeet were no more unconscionable than the current process of negotiation.

Indian tribes are unwilling to subject their water rights to State Court adjudication due to a history of hostility in State Courts, as reflected most recently in the *Wind River* case. This case was prosecuted by the State of Wyoming following the 1981 Supreme Court case in *San Carlos*. The State of Wyoming sought to adjudicate the waters of the Big Horn Basin, the permanent home and abiding place of the Arapaho and Shoshone Tribes of the Wind River Indian Reservation. The Tribes possessed valuable *Winters* doctrine water rights in the Big Horn River, its tributaries and the aquifers of that Basin. The outcome of the case was a tragedy for the Indian people. The case became the example that drives tribes to consider the negotiation policy adopted by the United States, Montana and Arizona rather than proceed in State Court in McCarran Amendment cases. The following summarizes the conclusions of the Supreme Court of the State of Wyoming in the *Wind River* case:

> *"The quantity of water reserved is the amount of water sufficient to fulfill the purpose of the lands set aside for the Reservation."* (753 P. 2nd 76, (Wyo 1988), p. 94).
>
> *"The Court, while recognizing that the Tribes were the beneficial owners of the reservation's timber and mineral resources ... and that it was known to all before the treaty was signed that the Wind River Indian Reservation contained valuable minerals, nonetheless concluded that the purpose of the reservation was agricultural. The fact that the Indians fully intended to continue to hunt and fish does not alter that conclusion."* (753 P. 2nd 76 (Wyo. 1988), pp. 97-98).
>
> *"The evidence is not sufficient to imply a fishery flow right absent a treaty provision."* (753 P. 2nd 76 (Wyo. 1988), p. 98).
>
> *"The fact that the tribes have since used water for mineral and industrial purposes does not establish that water was impliedly reserved in 1868 for such uses. The District Court did not err in denying a reserved water right for mineral and industrial uses."* (753 P. 2nd 76, (Wyo. 1988), p. 98).
>
> *"The District Court did not err in holding that the tribes and the United States did not introduce sufficient evidence of a tradition of wildlife and aesthetic preservation which would justify finding this to be a purpose for which the Reservation was created or for which water was impliedly reserved."* (753 P. 2nd 76, (Wyo. 1988), p. 99).

"The logic which supports a reservation of surface water to fulfill the purpose of the reservation also supports reservation of groundwater. ... 'Whether the [necessary] waters were found on the surface of the land or under it should make no difference'. Certainly the two sources are often interconnected. ... Acknowledging the above, we note that, nonetheless not a single case applying the reserved water right doctrine to groundwater is cited to us. ... In Colville Confederated Tribes v. Walton, supra 547 F. 2d 42, there is slight mention of the groundwater aquifer and of pumping wells, Id at 52, but the opinion does not indicate that 'their wells' are a source of reserved water or even discuss a reserved groundwater right. ... the district court did not err in deciding there was no reserved groundwater right." (753 P. 2nd 76, Wyo. 1988), pp. 99-100).

The only purpose for the Wind River Indian Reservation recognized by the Supreme Court of Wyoming was agricultural. The Arapaho and Shoshone had believed that the purpose of the reservation was to provide a permanent home and abiding place for their present and future generations to engage in pursuits of a viable economy and society. Despite oil and gas, they were denied reserved water for mineral purposes. Despite the need for industry in a viable economy, they were denied reserved water for industry. Despite a tradition of hunting and fishing, they were denied reserved water for wildlife and aesthetic preservation. Despite the existence of a valuable forest, they were denied reserved water for forest purposes. Despite the existence of valuable fisheries established from time immemorial, they were denied a reserved water right to sustain their fisheries.

Efforts are on-going that may place further restrictions on the use of the waters decreed by the Wyoming District Court and affirmed by the Wyoming Supreme Court. The decisions of the Wyoming courts underscore the reasons that Indian tribes feel compelled to negotiate rather than subject their water rights to State Court adjudication inspired by the U.S. Supreme Court decision in *San Carlos.*

The Wyoming Supreme Court found heavily against the Indians. The denial of a reserved water right for groundwater is but one example of the presence of a will in State Court that departs from proper consideration. To arrive at its opinion on groundwater, the Wyoming Supreme Court was inconsistent in its logic and relied upon factual errors. First, it is illogical that the Wyoming Supreme Court could acknowledge that an Indian reserved right should extend to both surface water and groundwater and then conclude that there was no reserved groundwater right. Second, the Court's research was inadequate at best, and did not reveal any cases in which a reserved groundwater right was granted. For the Court to base its denial of a groundwater right on its failure to find a reserved groundwater case requires careful review by the Tribes.

The Wyoming Supreme Court cited *Colville Confederated Tribes v. Walton* as a case that does not indicate that Indian wells were a source of reserved water or that a reserved right to groundwater has ever been indicated. Study of the *Colville* decisions shows clearly that groundwater was the subject of the case:

"Because the surface water of No Name Creek has a hydraulic relationship with the underlying aquifer, these actions include rights to both surface and ground waters of the creek basin.... Using water diverted from No Name Creek and water pumped from an irrigation well drilled in the 1970's, Waltons are presently irrigating 105 acres. ... In 1975, the Tribe initiated an extensive irrigation project in the basin. Wells were drilled on the northern allotments to provide irrigation waters for the northern acres, and some well water was pumped into No Name Creek to serve the needs of the two southern allotments. ..." (460 F. Supp 1320 (1978), pp 1323 and 1324). (Emphasis supplied).

"The Colville Confederated Tribes initiated this action a decade ago. They sought to enjoin Walton, non-Indian owner of allotted lands, from using surface and groundwaters in the No Name Creek basin. ... The No Name Creek is a spring-fed creek flowing south into Omak Lake, which has no outlet and is saline. The No Name Creek hydrological system, consisting of an underground aquifer and the creek, is located entirely on the Colville Reservation." (647 F. 2d 42 (1981)). (Emphasis supplied).

"This dispute involves respective rights of the Colville Confederated Tribes (Tribe), Indian allottees and Walton to share in the water from the No Name Creek Hydrological System, which was originally reserved for the Tribe under the Winter's doctrine, when the Colville Reservation was created. ... The Tribe currently pumps water from the aquifer into No Name Creek during spawning season. ... No Name Creek is a spring-fed creek which originates on Allotment 892 and flows through Walton's allotments and the Indians' southern allotments into Omak Lake, a saline lake with no outlet. The creek and an underground aquifer underlying Indians' northern allotments and the northern tip of Walton's allotment, No. 525, constitute the No Name Creek Hydrological System." (752 F. 2d 397 (1985)). (Emphasis supplied).

Clearly, the U.S. District Court and Ninth Circuit Court of Appeals recognized Indian reserved water rights in the No Name Creek Hydrological System, that the No Name Creek Hydrological System included surface and underground waters and that the Colville Confederated Tribes pumped water from the underground waters into No Name Creek. The statement by the Wyoming Supreme Court that *Colville* does not discuss a reserved water right to groundwater cannot stem from a reading of the case.

Because the petition for certiorari in the United States Supreme Court did not present the issue of groundwater, the ruling in the Wyoming Supreme Court denying a reserved water right to groundwater on the Wind River Indian Reservation was left standing in Wyoming.

Examination of the actions of the U.S. Supreme Court in the Wyoming case is also required by the Tribes:

"The petition for writ of certiorari to the Supreme Court of Wyoming is granted limited to Question 2 presented by the petition." (109 S.Ct. 863 (1989)).

Question 2 of the petition from the Supreme Court of Wyoming was as follows:

"In absence of any demonstrated necessity for additional water to fulfill reservation purposes and in presence of substantial state water rights long in use on reservation, may reserved water right be implied for all practicably irrigable lands within reservation set aside for specific Tribe?" (57 LW 3267 (October 11, 1988)).

The U.S. Supreme Court, limited its review to Question Number 2. Acting without a written opinion and deciding by tie vote, the U.S. Supreme Court affirmed the decision of the Supreme Court of the State of Wyoming that water may be reserved for an Indian Tribe, despite the fact that state water rights have been in use for a long time. The following argument by the State of Wyoming was not sustained by the U.S. Supreme Court, but a change in vote by a single justice would have reversed the decision and severely damaged the *Winters* doctrine water rights of the Indian people. The following is the Wyoming statement of the sensitivity issue considered by the U.S. Supreme Court:

"The sensitivity doctrine takes its name from this passage:

> *'I agree with the court that the implied-reservation doctrine should be applied with sensitivity to its impacts upon those who have obtained water rights under state law and to Congress' general policy of deference to state water law.'* United States v. New Mexico ...

... There is strong indication that New Mexico does not apply to Indian reserved water rights ... The Ninth Circuit has nonetheless gleaned useful guidelines from it for use in Indian reserved water cases. ... It is thus not clear whether the sensitivity doctrine, requiring the quantification of reserved rights with sensitivity to the impact on state and private appropriators, applies here. ... Deletion of the upstream storage requirement which was intended to protect appropriators from sudden depletion by the diversion of water for the five future projects does not manifest insensitivity to other water users ... Nor does this court's elimination of 10% diversion reduction for future projects violate sensitivity doctrine. ... In the case at bar, the purpose of the reservation for which water is reserved is narrow - agriculture only. The right was quantified based on PIA - the master and the court rejecting some 50,000 acres originally claimed by the United States and the Tribes. The Indians' claim was further reduced by requiring an efficiency increase in historic lands. All of this evidences a sufficient sensitivity to the water needs of other water users. With the exceptions noted above we affirm the quantification of the reserved water right." (753 P. 2nd 76 (Wyo. 1988), pp. 111 and 112).

But with the Supreme Court of the United States within one vote of damaging a body of law protecting the tribes from the competition of states, the tribes are compelled to seek any alternative, including negotiation with a state, rather than proceeding in a McCarran Amendment adjudication in State Court. The question remains, however, of the validity and the propriety of a negotiation that requires the Tribes to settle their water rights under the circumstances prevailing in Montana, Arizona, other western states and in the United States Supreme Court.

The decision in *Wind River* is hopefully limited to the State of Wyoming on critical issues, namely that Indian reserved rights do not apply to groundwater; the absence of a reserved water right for forest and mineral purposes; the absence of a reserved water right for fish, wildlife and aesthetic preservation; and the reduction of the Tribes' claims to irrigation from 490,000 to less than 50,000 acres.[4] The acreage of irrigation finally awarded to the Wind River Arapaho and Shoshone Tribes for future purposes was 48,097 acres involving approximately 188,000 acre-feet of water annually.

[4] In determining the Tribes' claims to practicability irrigable acreage, the United States (trustee for the tribes) began with an arable land base of approximately 490,000 and relied on its experts to arrive at over 88,000 *practicably irrigable acres*. The claim was further "trimmed" by the United States to 76,027 acres for final projects. The acreage was further reduced during trial to 53,760 acres with a total annual diversion requirement of about 210,000 acre feet. (Teno Roncalio, Special Master, In Re: The General Adjudication of All Rights to the Useof Water in the Big Horn River System and all Other Sources, State of Wyoming, concerning reserved water right claims by and on behalf of the Tribes of the Wind River Indian Reservation, Wyoming, December 15, 1982, pp. 154 and 157).

APPENDIX B

TESTIMONY REGARDING S. 1370
PRESENTED BY THE
MNI SOSE TRIBES OF THE MISSOURI RIVER BASIN
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
SUBCOMMITTEE ON WATER AND POWER

OCTOBER 23, 1991

The Mni Sose Tribes of the Missouri River Basin (Standing Rock, Rosebud, Oglala, Yankton and Santee) and, we believe, the remaining 26 tribes of the Basin, seek Missouri River Basin Pick-Sloan preference power allocated by the Western Area Power Administration. In order to insure this result we request that the following amendment be incorporated in S. 1370:

SECTION 1. ... The Secretary of the Interior, in cooperation with the Secretary of Energy, will make available, as soon as practicable after the date of enactment of this Act, ... preference power ... to meet the needs of the Missouri River Basin Tribes for residential and all other purposes and two existing nonFederal irrigation projects known as -- ... Haidle Irrigation Project ... and Hammond Irrigation District

In the absence of the amended language, we are forced to oppose S. 1370 because we recognize that a more comprehensive piece of legislation is needed for the re-allocation of MRB-PS energy in order to insure that the needs of all preference entities are adequately met.

The 1944 Flood Control Act (58 Stat. 887) approved the Missouri River Basin Pick-Sloan Plan for irrigation, navigation hydropower and other purposes. The Bureau of Indian Affairs, acting on behalf of the Indians of the Missouri River Basin, supported the legislation on the following grounds:

Insofar as the Indian irrigation and power interests are concerned, the report [Senate Document 191] seems to give them adequate consideration.

We respectfully submit that the report may have given the tribes adequate consideration, but the implementation of plans approved by the Act has given the tribes virtually no consideration. Little irrigation development identified by the Missouri River Basin Pick-Sloan Plan has been implemented on Indian reservations. Only small amounts of pumping power have been made available to some tribes for limited irrigation. The tribes, which qualify as "preference" bodies, have never been able to contract with the Western Area Power Administration for low-cost federal hydropower.

The Western Area Power Administration, federal marketing agency for Missouri River Basin Pick-Sloan hydropower, has recently initiated a "public" process for re-contracting of Missouri River Basin Pick-Sloan power. Existing contracts for the sale of "preference" power will end in year 2000, and Western is taking steps to re-contract the power. The tribes of the Missouri River Basin seek a direct allocation of 25 percent of the power to be marketed. An allocation of this magnitude would raise electrical rates to customers in the Basin's rural electrical cooperatives, principle recipients of the power at present by an estimated 3.6 Percent.

The Indian tribes are now participating in the "public" process of the Western Area Power Administration for re-contracting of this valuable federal asset. It is important to the Indian tribes because federal power is sold at a rate of approximately 10 mils ($0.010) per kilowatt hour while the rural electrical cooperatives that sell electricity to the tribes and their membership charge from 35 to 45 mils ($0.035 to $0.045) per kilowatt hour.

We are shocked to find that the "public" process is not truly public. Western intends to market from 70 to 98 percent of the preference power to existing customers, thereby excluding the tribes and others from consideration as new customers. Of the 2 to 30 percent of the present power resource to be handled differently, part will be marketed to old customers that demonstrate initiative in energy conservation, part will be removed from the market process due to reduction in the firm power resource and the remaining will be contracted to new customers. Any new customers must be preference customers as defined by the 1944 Flood Control Act. Western agrees that the tribes qualify as preference customers. But in addition to preference status, any new customers must also qualify as a "utility." With minor exception, the tribes do not qualify as utilities and are effectively excluded from the marketing process.

Western intends to make decisions on the amount of power made available to new "utility" customers over the next 6 to 12 months. Your assistance is urgently requested by the tribes of the Missouri River Basin. We petition the Water and Power Subcommittee to hold a hearing in the current session of Congress to address the ways and means of meaningful tribal participation in the direct purchase of low-cost federal energy produced by the Missouri River Basin Pick-Sloan program. Legislation may be our only avenue. We are hopeful that the Subcommittee will sponsor low-cost federal hydropower directly to the Indian tribes by wheeling arrangements across the existing transmission and distribution systems that serve the Reservations.

One of the principle provisions of the 1944 Flood Control Act with regard to electric power and energy has never been used to the advantage of the Indian tribes. That provision is as follows:

> *The Secretary of the Interior is authorized from funds to be appropriated by the Congress, to construct or acquire, by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at such projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies and cooperatives and privately owned companies.* (Sec. 5, 58 Stat. 887, p. 890).

We believe that wheeling is a sensible mechanism for making wholesale, preference power available to the tribes at this point in time. If wheeling is not workable, a question of transmission and related facilities may be necessary.

Many of the Indian tribes contributed extensive tracts of land for the construction of the Missouri River Basin Pick-Sloan dams and reservoirs. All of the tribes have vested Winters doctrine rights to the use of water in the Missouri River and its tributaries that are being utilized to generate federal hydropower. Our contributions to the project are great, but our benefits from the project are virtually none.

We will work with the Subcommittee staff to seek hearings. The hearings will be attended by all tribes with interest in this matter that can attend. We seek the hearings to review legislative possibilities which are clearly needed if we are to participate directly in the benefits of low-cost federal hydropower on the Missouri River.

APPENDIX C

STATEMENT OF THE STANDING ROCK, OGLALA, ROSEBUD AND YANKTON SIOUX TRIBES

SCOPING MEETING
HOLIDAY INN, BROOKINGS, SOUTH DAKOTA
JUNE 26, 1991

The Standing Rock, Oglala, Rosebud and Yankton Sioux Tribes have associated to pursue an allocation of Missouri River Basin Pick-Sloan hydropower. Representatives of the association have been informed by the Western Area Power Administration that the Agency will allocate from 70 to 98 percent of the federal, firm hydropower resource to existing preference customers in the power marketing initiative for year 2000 and beyond. The remaining 2 to 30 percent of MRB-PS firm, hydropower resources will be allocated to new customers. The decision on allocation of power and energy to new and existing customers is anticipated by Western by 1993.

The above-mentioned Indian Tribes have resolved to join with all other Tribes of the Missouri River Basin and to pursue an allocation of 25 percent of the federal MRB-PS firm hydropower. This would result in an allocation of approximately 500 megawatts of the total 1,984 to 2,012 megawatts available for allocation. The Tribes of the Basin can demonstrate that the Reservations have the lowest per capita income levels in the region and the nation. The Tribes are paying for electricity at substantially the same cost as coal-fired generation. It is respectfully submitted that a federal purpose of the highest dignity can be served by allocation of preference power to the Basin's Indian Tribes, thereby bringing the first substantive benefits from MRBPS to the Indians since the project's inception.

The Indian Tribes seek the assistance of the Western Area Power Administration in the implementation of its power marketing initiative. The initiative should allocate sufficient electrical energy to the 26 Tribes to provide them with significant amounts of preference power at wholesale rates ($0.01029 per kilowatt hour). Most of the Tribes are presently paying between $0.040 and $0.045 per kilowatt hour for purchased energy (in addition to distribution costs).

The 26 Tribes of the Missouri River Basin qualify as preference customers for the sale of power:

> *"Preference in the sale of ... power and energy shall be given to public bodies and cooperatives. The Secretary of the Interior is authorized, from funds to be appropriated by the Congress, to construct or acquire by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at such projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives, and privately owned companies."* (58 STAT. 887, December 22, 1944 Flood Control Act).

The Missouri River Basin Tribes are embraced by the provisions of the Pick-Sloan Act and qualify as preference entities. Some of the Tribes are receiving small amounts of preference and pumping power for irrigation development, but none of the Tribes are receiving sufficient quantities of preference power to significantly impact the rates paid by Tribal members for residential and commercial purposes.

Distribution of electrical power to the Missouri River Basin Tribes is by rural electrical cooperative, public utility or private utility. The Tribes do not generally qualify as utilities. Western's power marketing initiative must necessarily provide a mechanism for wheeling of preference power to Indian Tribes through existing transmission and distribution facilities. It is recognized that most generation and transmission cooperatives and RECs have contracts for the purchase of power from generation facilities, such as Basin Electric. Demands for non-federal energy are increasing. As existing contracts with generation and transmission entities terminate, larger allocations of federal energy can be directed to the Tribes without affecting contracts designed to ensure repayment of coal-fired power plants.

It is respectfully requested that Western advise this association of Tribes by letter of the need for Congressional direction in its power marketing initiative. Historically, the Tribes have not been able to compete successfully for federal power with other preference customers, and allocations by the Secretary of Energy, comparable to the on-going process, are generally not subject to review outside the Department. We seek input from Western and request that you correspond on the critical issues of allocation of energy to the Tribes which are summarized as follows:

1. An assessment is needed by Western of the power of the Secretary or the need for Congressional authorization and direction to reserve from competition an equitable allocation of firm, wholesale hydropower for the Missouri River Basin Tribes

2. A mechanism for delivery of allocated energy to the Tribes considering existing transmission and distribution by rural electrical cooperatives is needed

3. Joint investigations by the Tribes and Western are needed to quantify present and future Indian energy demands and the impact of a federal allocation of preference power to the Tribes on per capita income and general economic development.

4. A summary of other issues requiring resolution before federal energy can be allocated to the Tribes including, but not limited to, the effect of existing contracts between rural electrical cooperatives and their power suppliers is needed.

To address Tribal concerns, an additional scoping meeting in Billings, Montana, in July 1991 is requested.

Mr. MILLER. Ms. Knight-Frank.

STATEMENT OF JUDY KNIGHT-FRANK

Ms. KNIGHT-FRANK. I am Judy Knight-Frank, chairman of the Ute Mountain Tribe. Our headquarters are in southwestern Colorado. We own lands and have tribal members residing in the State of Utah, and we also extend into the State of New Mexico. The San Juan Power Plant is five miles south of our reservation in New Mexico and also the Four Corners Power Plant is located there.

Mr. Chairman and Members of the committee, on behalf of the Ute Mountain Ute Tribe I want to thank you for inviting the tribe to testify on the issue of Western Area Power Administration's proposed allocation of power in the recent Draft Environmental Impact Statement.

The Ute Mountain Ute Tribe is committed to conservation and energy efficiency. We are now making arrangements for an energy audit to assess the current situation on our reservation. In our efforts to achieve higher levels of conservation, we must have the same access to Federal hydroelectric power that other preference entities currently served by Western are able to enjoy.

My tribe has a real and immediate need for the low-cost power which Western can provide. This need is based on our extremely low per capita income rate, high unemployment rate, and the fact that our local electrical cooperative charges high rates when compared to the rates which should be available to preference entities like the tribe.

As many on this committee know, the Indian tribes are generally considered to be the poorest of minorities in the United States, and my tribe is no exception. Because of this, it has been and continues to be the policy of the Ute Mountain Ute Tribal Council to do everything possible to ease the economic burdens of tribal members.

Lowering the cost of electricity is one way to do this, and has both the effect of reducing personal expenses and allows the tribal enterprises to operate more profitably, resulting in increased employment of tribal members.

For this reason, the tribe has embarked on a mission to obtain an allocation of power from Western, but has been unsuccessful. I would direct the committee to the tribe's written testimony for a detailed explanation of our efforts. However, the committee should know that Western has transmission line rights-of-way across tribal lands. Yet the tribe receives no benefit from them whatsoever.

It seems ironic that many of Western's existing customers benefit from power which crosses our homelands, but the tribe cannot obtain a desperately needed allocation of power from this same entity which encumbers our lands.

Since we are not trying to get an allocation of power, we are very concerned about the impacts the power allocation alternatives in Western's EIS would have on our current attempts and on available power in the future.

Our main concerns are, one, because the EIS does not include an alternative which provides for a resource pool of more than 10 percent, there will be little if any power left over to allocate to tribes.

Two, the preferred alternatives are partial to Western's existing customers and do not take into account the resource needs of preference entities such as tribes which are not current customers.

Three, until further research is performed, Western cannot know when other preference entities will request contracts for power.

Four, nowhere in the EIS is any definition of how resource pool power or project-by-project basis power will be allocated.

Five, the tribe feels there must be a needs-based method for determining who will get an allocation so that the unique hardships which all tribes endure will be appropriately considered.

Six, we question the environmental analysis in the EIS. It does not consider the impacts of allocating power to preference entities, such as the tribe, which are not current Western customers. Because we feel this alternative must be considered for there to be what Western calls an "equitable allocation of resources," the failure to do an environmental analysis is significant.

Seven and finally, Western's failure to consider tribes in the process is a breach of the trust relationship which all Federal agencies have to tribes.

Once again, I thank you for providing me with the opportunity to speak on behalf of my tribe. I would ask that the committee refer to our written testimony for a more detailed explanation of our position on Western EIS. On behalf of the Ute Mountain Indian Tribe I invite you to come visit our homelands and experience the beauty of southwestern Colorado.

Thank you.

The CHAIRMAN. Thank you very much.

[Prepared statement of Ms. Knight-Frank follows:]

TESTIMONY BEFORE THE U.S. HOUSE OF REPRESENTATIVES
HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATION

June 16, 1994

WESTERN AREA POWER ADMINISTRATION
ENERGY PLANNING AND MANAGEMENT PROGRAM
DRAFT ENVIRONMENTAL IMPACT STATEMENT: PROPOSALS FOR ALLOCATION OF 7169 MEGAWATTS OF FEDERAL HYDROELECTRIC POWER

SUBMITTED BY:

JUDY KNIGHT-FRANK, CHAIRMAN
UTE MOUNTAIN UTE INDIAN TRIBE
TRIBAL OFFICE COMPLEX
TOWAOC, COLORADO 81334
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Mr. Chairman and Members of the Committee:

I want to thank you for inviting the Ute Mountain Ute Indian Tribe ("Tribe") to testify before you on the very important issue of federal power allocation. The following sets forth the Tribe's written testimony to the Subcommittee on Oversight and Investigation. It includes commentary on recent negotiations and discussions with representatives from the Bureau of Reclamation and the Western Area Power Administration ("Western") with respect to the Tribe's attempts to obtain an allocation of Western power for economic development projects located on our homelands. Currently, the single largest need for power comes from the Ute Mountain Ute Indian Irrigation Project ("UMIP"). This project is the end use of water delivered by the Dolores Project, a project which the U.S. Government is obligated to complete under the Colorado Ute Indian Water Rights Settlement Act of 1988. After you have reviewed our testimony, please feel free to contact the Tribe with any further question you may have.

I. Primary Concerns of the Ute Mountain Ute Indian Tribe:

The Ute Mountain Ute Indian hereby submits this testimony to the Committee Natural Resources, Subcommittee on Oversight and Investigation, on Western's Energy Planning and Management Program Draft Environmental Impact Statement ("DEIS"). Our primary concerns are the present need for low-cost power on our homelands, the future economic development of this and all Tribes and the restrictions which the DEIS, if adopted as written, would impose on such development. The Tribe will herein explain that because the DEIS does not include an alternative which provides for a resource pool of more than 10% and intends to extend the majority of resources to existing customers, it is deficient. Furthermore, the DEIS fails to provide guidelines and policies to be utilized in determining how existing power is to be re-allocated or how the resource pool would be allocated. This is of extreme concern to the Tribe as we are currently a potential preference entity with a real need for low-cost power. Although we are not currently receiving any power from Western, we have an immediate need for such power to operate the Water Settlement related irrigation project referenced above on our homelands.

The Tribe commends Western for stressing the importance of conservation in its DEIS and making the establishment of conservation and energy efficiency plans a primary consideration in the allocation of power among its customers. The Ute Mountain Ute Indian Tribe is committed to conservation and energy efficiency and is making arrangements for an energy audit to access the current situation on the Reservation. In our efforts to achieve higher levels of conservation, however, it is vital that the Tribe have the same access to Federal Hydroelectric Power that other preference entities currently served by Western are able to enjoy.

II. History of the Tribe's Attempts to Obtain Power Allocation From Western and its Negotiations and Agreements With the Local Rural Electric Cooperative:

A. Initial Discussions with Western:

As noted above, the Tribe has been unsuccessful in its attempts to obtain power from Western. As early as 1991, the Tribe began discussions with representatives from Western's Salt Lake City office on how it could obtain an allocation of power for economic development purposes on the Ute Mountain Ute Indian Reservation. Because of the relatively high rates which Empire Electric Association, Inc. ("Empire Electric") our local rural electric cooperative charges, it is imperative for further economic growth on the Reservation that the Tribe have a firm supply of low-cost electric power. (Please see discussion below on this point). At that time, Western informed the Tribe that an act of Congress would be needed to direct it to make an allocation of power. Their reasoning why this was necessary was that because the Tribe was not a preference entity, nor a current customer, nor an entity which was reserved power under the Colorado River Storage Project Act ("CRSP"), Western could not administratively allocate power to it.

At that time, the Tribe began to draft language for such an Act of Congress and decided to come back to the issue at a later date. However, growing loads on our homelands, which include the UMIP, forced the Tribe to re-examine the issue sooner than had been anticipated.

B. Shortage of Available Capacity and Power/Execution of Utility and Wheeling Agreements with the Local Rural Electric Cooperative:

Approximately one year ago, Empire Electric, informed the Tribe that loads on the Reservation were about to exceed their capacity as well as the availability of power. Therefore, of the 400kw which the Tribe had contracted with Empire Electric to provide to UMIP, 200kw had to be allocated to another economic development project (RV park). This was only a temporary measure and the UMIP will need the entire 400kw within the next three months. A substation necessary for delivering any available power to the Reservation is planned as are upgraded transmission lines.

The Tribe recently executed Utility Franchise, Service, Delivery and Wheeling Agreements with Empire Electric. Our research indicates these are the first agreements of this type between a rural electric cooperative and an Indian Tribe. Therein, Empire Electric has recognized the Tribe's status as a sovereign government and submitted to its jurisdiction and laws. Importantly, provisions have been made for Empire Electric to wheel an allocation power from Western so long as such wheeling is lawful. Empire Electric raised concerns about "retail wheeling" which will be discussed below and which the Tribe requested Western to address in its DEIS

C. Recent Negotiations with Western, the Bureau of Reclamation, the Department of Energy, Congressmen, Senators and Their Respective Staffs:

As soon as the shortage of power was brought to the Tribe's attention, we immediately renewed discussions with Western concerning an allocation of power for the Tribe. Again, Western informed us that action by Congress would be necessary in order for them to provide the Tribe with an allocation of power. In this instance, Western's representative's referenced not only the fact that the Tribe was not a utility but also that power had not been reserved for the UMIP portion of the Dolores Project under either the Colorado Ute Indian Water Rights Settlement Act of 1988 or CRSP as their reasons.

The Tribe then met with representatives from the Bureau of Reclamation ("Bureau") which is the agency which determines what CRSP projects will have power reserved for them and for what uses that power is available. Bureau representatives in Salt Lake City shared with the Tribe an agreement between it and Western on power allocation for CRSP projects. The agreement reserves power for "pumping and/or lifting" of water for projects. This is called "project use power." Unfortunately, the Tribe has the good luck of being able to "gravity flow" all of the water needed for UMIP. Bureau representatives indicated that it would be extremely difficult to modify the agreement with Western to provide the Tribe with its needed power.

For these reasons, we again went to our Colorado Congressional Delegation which includes Congressman Scott McInnis and Senators Brown and Campbell for assistance. They all indicated a willingness to move forward with legislation directing Western to allocate power to the Tribe for all of its economic development projects, including but not limited to UMIP. The quickest way to realize the goal of obtaining the allocation was first thought to be adding the relevant language to the appropriations bill. Although staffpersons on the Senate side agreed with this approach, House appropriations staff indicated such language would be considered "authorizing" language and would be deleted from any appropriations bill. Thus, the Tribe was back to having an Act of Congress passed specifically for the purpose of providing it an allocation of Western power. This process could take up to two to three years, far longer than the Tribe can wait to satisfy its immediate needs.

Recently, we met with Kyle Simpson in the Department of Energy. He has indicated that Western can in fact administratively allocate power to the Tribe for all of its needs. Apart from the Tribe's other economic development projects, however, the Bureau should be compelled to except all Indian Irrigation projects from its "project use power" definition, thereby allowing Western to give this and other Tribe's much needed allocations of power for projects such as UMIP. In its meeting with Mr. Simpson, the Tribe did mention the fact that Western currently has both 230kv and 340kv transmission lines running across the Reservation. Western has these right-of-ways across tribal lands and the Tribe receives no benefit whatsoever therefrom. It seems ironic that many of Western's existing customers benefit from power which crosses our homelands but the Tribe cannot obtain a desperately needed allocation of power from the same entity which encumbers our lands. We hope our recent discussions with DOE officials will help to remedy that situation but are nevertheless concerned about the proposed DEIS.

With respect to the above summary of the Tribe's attempts to obtain the allocation of power discussed above, we are concerned that the structure of the alternatives proposed by Western described in the DEIS may only serve to further impede our efforts.

III. Alternatives Presented in the DEIS; Other Alternatives Which Should be Included:

Analyses of alternatives 2-10 indicate they will have the effect of allocating between 90-98% of Western's power to its existing customers for up to 35 years. At the most, only ten percent (10%) of Western's available resources would be available for re-allocation. Such action would make it extremely difficult, if not impossible, for the Ute Mountain Ute Indian Tribe to obtain an allocation of power from Western in the future. An additional concern with re-allocation, which will be discussed below, is that we find no guidelines or policies in the DEIS explaining how the resource pool will be allocated.

It is equally important that alternatives 2-10 do not provide a large enough resource pool for preference entities such as Indian Tribes to develop and grow. Considering the massive growth in the Southwest region of the United States, even the largest resource pool, at 10%, would not be enough to ensure that Indian Tribes within Western's jurisdiction will receive an allocation. If the Power Marketing Initiative alternatives are to be retained, we would strongly support the addition of an alternative which includes, at a minimum, a 25% resource pool.

Although the Tribe cannot support alternatives 2-10 as they are now formulated, we can support alternatives 11 and 12 so long as certain issues are addressed. Alternatives 11 and 12 would allow Western to make power allocations and contract extensions on a project-by-project basis. The issue which must be addressed here is that Western could still favor its existing customers in such a project-by-project allocation regime. It is important that Western not establish a generic power allocation policy when it does not know how much power will be available from projects such as CRSP or what entities will seek to purchase the power.

IV. Determination of How Resource Pool Power or Project-by-Project Basis Power Would be Allocated:

With reference to the method which will be used to allocate the resource pool or select projects to contract with, we do not find in the DEIS any definition an allocation regime. Except for the general preference toward entities which have established energy conservation practices in accordance with the DEIS, it is unclear where **new** preference entity customers will fit in. (emphasis added). This is of particular concern to the Tribe, since as a preference entity, we are entitled to receive power from Western. Currently, Western gives preference to entities with utility status but has not followed established guidelines in doing so. Because this issue is not discussed in the DEIS, it is further deficient. Utility status is defined by Western as:

> ...The primary consideration of 'utility status' is that an entity must control and operate its own distribution system...[I]f a conflict arises over contracting with a utility or non-utility[,] Western will first contract with the entity considered to have 'utility status'....

59 Fed.Reg. 8264, Withdrawal of Proposed Allocation Criteria, Allocations, and Rates for Interim Power from Navajo Generating Station, Western Area Power Administration. As the Tribe has its own distribution system for the Ute Mountain Ute Indian Irrigation Project ("UMIP"), it is a utility for at least that system. Although we have had discussions with Western concerning an allocation of power for UMIP, the Tribe has been unable to obtain such an allocation of power for this or other purposes.

Questions concerning "retail wheeling" have been raised by Empire Electric. They have indicated that it is Western's policy not to provide power to an entity which does not have utility status. According to the above, the Tribe does have utility status in so far as UMIP is concerned even though it does not have an utility authority per se. The problem of how resource pool power or project-by-project basis power will be allocated to a non-utility preference entity must be addressed in the DEIS.

V. Tribe's Need For Low-Cost Power:

The Ute Mountain Ute Indian Tribe has a real need for low-cost power on our homelands. This is based on our extremely low per capita income rate, high unemployment rate and the fact that our local rural electric cooperative, Empire Electric, charges relatively high rates when compared to the rates are available to preference entities like the Tribe. Indian Tribes are generally considered to be the poorest of minorities in the United States and the Ute Mountain Ute Indian Tribe is no exception. For this reason, it has been and continues to be the policy of the Ute Mountain Ute Tribal Council to do everything possible to ease the burdens of Tribal members, both financial and otherwise.

A significant financial burden for Tribal members, their families and Tribal enterprises is the high cost of electricity. If the Tribe is able to obtain an allocation of power from Western, we could significantly reduce the personal expenses of our Tribal members and allow our Tribal enterprises to operate more profitably, resulting in increased employment of Tribal members. A firm supply of low-cost power will initiate a chain reaction of benefits throughout the Tribe. Importantly, the lack of low-cost power is hindering the development of further economic development projects. Proposals for these new projects must use the higher costs assessed by Empire Electric, and for that reason, may not be feasible unless lower cost electricity is available. The need for an allocation of power from Western is very real and we invite members of the Committee to come visit our homelands. Here, you can see the benefits economic development projects bring to the Tribe and how a firm supply of low-cost power will encourage further development.

A. Power for the Economic Development on the Ute Mountain Ute Indian Reservation:

In our attempt to achieve economic self-sufficiency for the Ute Mountain Ute Indian Tribe and its members, the Tribe is pursuing numerous economic development projects on our homelands. Unfortunately, we are running into a shortage of available power from Empire Electric. One of these projects is UMIP, a 7,500 acre irrigation project which is being developed as part of the United States' obligations to the Tribe under the Colorado Ute Indian Water Rights Settlement Act of 1988 ("Settlement Act"). The Dolores Project, which UMIP is a feature of, is part of the Settlement Act. Increased profitability of UMIP will depend in large part on the availability of Western power, whether through Western's CRSP contracts or otherwise. Increased profits mean increased jobs for Tribal members.

The Tribe has asked Western for an allocation of approximately 5 megawatts of project power from CRSP or as a preference customer to operate UMIP and for other economic development purposes. This request was turned down essentially by the Bureau of Reclamation, thereby mandating Western's response that only pumping or lifting power, i.e., project use power, can be allocated and, because the Tribe can gravity flow all of its water to the center pivots, no pumping or lifting is needed. (See discussion in II-C, above). Western further supports its position with the argument that UMIP is not a utility even though it has its own distribution system. The Tribe should nevertheless be able to obtain an allocation of power from Western as it is a preference entity and owns and operates the distribution system for UMIP which should qualify it as a utility according to Western's own statements. Again, as noted above, this is a real problem which is not addressed in the DEIS.

B. Power for Individual Ute Mountain Ute Tribal Members and the Tribe's Establishment of a Utility Authority:

As noted above, the Tribe has a real need for low-cost power for the residents on our homelands. In our attempts to satisfy Western's requirements, we have established a plan of operation for a utility authority. All that would be left to do is purchase Empire Electric's system on the Reservation and retain personnel to administer the utility authority. For this reason, not only has the Tribe been unable to obtain an allocation of power from Western for UMIP which should already have utility status, but we have also been unable to obtain an allocation for the Tribe itself. As preference entities, we do not believe Tribes should be required to have an utility to obtain an allocation of power from Western.

We understand that the Oglala Sioux Tribe have raised this issue in their comments on the DEIS as well. We echo their concerns and strongly support the use of "energy credits" or other methods as a means of providing low-cost Western Hydroelectric power to tribal members without the need for establishing a utility authority. The establishment of a utility authority for the approximately 1800 inhabitants on our homelands would likely be an unjustified administrative burden and is, in fact, discouraged by the Rural Electric Association in the Department of Agriculture. Nevertheless, the Tribe is in position to go forward with a plan if it is absolutely required.

C. Evaluation of Need in Determining Whether Preference Entities That are Not Existing Customers will Receive Allocations of Western Power:

A related problem to the lack of a regime for determining how resource pool or project-by-project basis power will be allocated is the failure of the DEIS to consider the "need" of a new customer or applicant for Western power. As discussed above, the economic conditions on the Ute Mountain Ute Indian homelands are severe. Because the DEIS does not have a need-based method for evaluating the requests of new preference customers, such factors cannot be taken into account. It is the Tribe's position that the addition of a need-based method for reviewing new requests is vital to the "equitable allocation of resources" which Western espouses in its DEIS. Importantly, such a method will serve to uphold the trust relationship of all agencies and department of the United States to Indian tribes.

VI. Environmental Analysis:

The Tribe also questions the environmental analysis in the DEIS, which appears to conclude that locking in the existing allocation of power to Western customers will have the least environmental impact. The DEIS does not support this conclusion because it contains no analysis of the environmental effects of alternative power allocation regimes. As noted above, the Tribe strongly feels that an allocation regime which would ensure the availability of Western power to preference entities such as Indian Tribes should be included. The DEIS simply does not address the environmental impacts of providing CRSP or other Western Hydroelectric power to this or any other Indian Tribe.

VII. Summary of Ute Mountain Ute Indian Tribe's Comments:

The Tribe has raised herein some very pertinent concerns about the DEIS which Western proposes. Our concerns are particularly appropriate given Western's statements in the DEIS that it seeks an "equitable allocation of resources." Although the Tribe understands the need for planning stability which results when a Western customer can depend on its Federal power commitment, no allocation regime can be "equitable" without taking into account the needs of this and many other tribes within Western's service area.

These concerns include the DEIS' lack of an alternative which provides for a resource pool of more than 10%, the DEIS' lack of guidelines and policies for determining how power will be re-allocated either under the resource pool on a project-by-project basis and the lack of a need-based method for evaluating new customers. Another important issue which the Tribe raises herein involve unsupported conclusions on environmental impacts of included alternatives and options which were not considered but should have been. One significant example of such an alternative is one that considers the allocation of power to preference entities which are not current Western customers.

At the same time, the DEIS fails to address concerns about the allocation of power to preference entities which Western does not grant utility status to. How will tribal entities, many of which have the unique status of being preference entities without utility authorities, obtain power from Western if there are no provisions for doing so contained in the DEIS? In this regard, it will be important for Western to follow its own guidelines and statements regarding what is to be considered a utility.

The Tribe greatly appreciates the opportunity to provide both written and oral testimony to the Committee on the very important issues raised by Western's DEIS and again invite you to come visit our very beautiful homelands. We seek to obtain an allocation of power from Western as soon as possible and the alternatives proposed in the DEIS will affect our attempts to do so now and our ability to retain any allocation in the future after current Western contracts expire. Finally, the Tribe hopes the Committee can impress upon Western and the Bureau of Reclamation the need to acknowledge the unique status of Tribes as sovereign governments which those agencies owe a trust responsibility to, the same trust responsibility which the Bureau of Indian Affairs is charged with.

The CHAIRMAN. Mr. Epperson.

STATEMENT OF MICHAEL EPPERSON

Mr. EPPERSON. Chairman Miller and members of the Subcommittee on Oversight and Investigations, the San Francisco Bay Area Rapid Transit district is glad to have the opportunity to present our position to you.

Our position is that BART is a desirable recipient of power marketed by the Western Area Power Administration. However, the Draft Environmental Impact Statement, as written, has the potential of locking BART out of additional power allocations in 2004 and thereafter.

BART is a transit district created, organized and operated pursuant to Sections 28500 to 29757 of the California Public Utilities Code. It is governed by a nine-member publicly elected board of directors.

BART began rapid transit operations in 1972 with an average of 15,000 weekday passengers. Last year, BART averaged more than 253,000 weekday passengers. In another two years, weekday ridership is expected to exceed 283,000.

BART operates 34 passenger stations and 71 miles of track in the counties of Alameda, Contra Costa, San Francisco and San Mateo. Ten more passenger stations and 33 miles of new track are under construction. In addition to the rail network, buses connect BART with Solano, Marin, and Santa Clara Counties. BART also has weekday patrons from San Joaquin and Sonoma Counties. All in all, BART regularly serves patrons in nine counties.

This year, BART will require approximately 59 megawatts of electric capacity to operate its system. Beginning July 1st of this year, 4 megawatts will come from the Western Area Power Administration Central Valley Project. In the year 2000, when all present CVP contracts expire, BART will require approximately 100 megawatts of capacity.

BART is an ideal recipient of Western power. BART provides an opportunity to make available to a broad spectrum of the public the economic benefits inherent in reclamation hydropower. Unlike many of Western's customers whose services are confined to a single community, BART serves 15 communities directly and many more through connecting bus systems and express bus services. The number of communities served directly by BART is continuing to expand as BART expands its system.

BART's electrically powered trains are clean air vehicles. Transferring riders from cars to BART improves air quality. BART mitigates traffic congestion, reduces the need for expensive highway expansion, provides affordable and efficient transit, and reduces the country's dependence on oil.

For BART's public, Central Valley Project power means lower electric costs. Lower electric costs mean lower fares. Lower fares mean greater ridership. Greater ridership means less traffic congestion and improved air quality.

It has been proposed that the Power Marketing Initiative from the EP&MP EIS be adopted by the Central Valley Project EIS for post-2004 allocations. Alternatives 2 through 10 in the Draft Program EIS propose that Western customers receive between 90 and

100 percent of the available power resources when their contracts expire. If applied to the Central Valley Project, these alternatives will have the effect of locking in present allocations of Central Valley Project power for the next 20 to 40 years.

It would seem imprudent for Western to establish a generic power allocation policy that locks in current allocations when Western does not know how much Central Valley Project power will be available to market and what entities will desire to purchase the power.

In addition, implicit in the allocation of public power is the exercise of national energy policy and the adoption of environmental standards. Can Western ascertain today that certain allocations will be in conformity with national policy and standards in place 20 to 40 years from now?

In addition to the environmental analysis in the Draft Environmental Impact Statement, the statement appears to conclude that retaining the existing allocation of power to Western customers is the best environmental option without analyzing the environmental effects of alternative power allocation regimes.

For example, the Draft Environmental Impact Statement does not consider the potential environmental benefits of increasing the future power allocations of certain customers. Increasing the allocation to BART would reduce BART's operating expenses and, thereby, lower fares; and lower fares increases ridership and yields a number of social benefits, including air quality.

Alternative 12 is the only alternative that gives Western the flexibility to respond to changes in national energy policy and environmental objectives and allows for entities such as BART to participate in the energy management initiative.

Alternatives 11 and 12 propose that Western make power allocation contract extension decisions on a project-by-project basis, as Western has done in the past. The difference between Alternatives 11 and 12 is that Alternative 12 provides a separate Integrated Resource Plan provision for small customers.

Large utilities generally have a broad range of demand-side and supply-side measures available to them to improve efficiencies. End-use customers are usually limited to improving the efficiency of the end-use facilities.

The IRP compliance requirements should be sensitive to the potential benefits each customer would receive, as well as the potential benefits to Western's system. It is quite possible for Western to set IRP requirements that, when applied to end-users, have no real benefit to the customer or to Western's system and could actually discourage participation in Western's marketing plan.

In conclusion to my testimony, I would like to respond to the issue of requiring utility status for new customers. I would like to point out that on page 11 of Western's draft environmental planning program's Environmental Impact Statement, it specifically states that new customer eligibility is limited to three factors: preference, utility status by a certain date, and being located in the marketing area. This is in a summary box rather than in the body of the draft report.

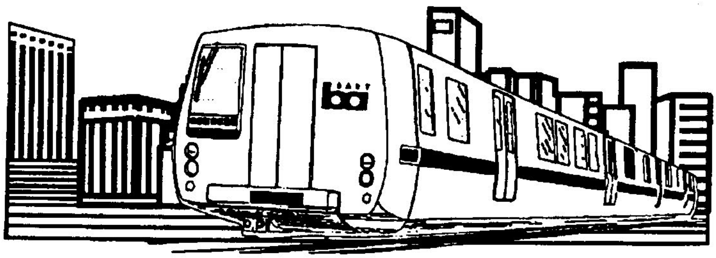
I wish to point out that Western serves many nonutility customers. And on page 59 of the draft report, they list how many customers they serve in each category. Within the Sacramento district itself, Western serves 26 Federal agencies and eight State agencies.

It is our understanding and presumption that it has been in the public interest for Western to serve these agencies. And we are of the opinion that utility status should not be a requirement for new customers, but rather that the value that they offer the public in terms of benefit from public power should be considered as it has been in the past.

That concludes my testimony. Thank you.

Mr. MILLER. Thank you.

[Prepared statement of Mr. Epperson follows:]



TESTIMONY OF THE SAN FRANCISCO BAY AREA RAPID TRANSIT DISTRICT

BEFORE THE SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS,
COMMITTEE ON NATURAL RESOURCES,
U.S. HOUSE OF REPRESENTATIVES

JUNE 16, 1994

Chairman Miller and members of the Subcommittee on Oversight and Investigations

My name is Michael Epperson and I am here representing the San Francisco Bay Area Rapid Transit District which is commonly known as BART. We are glad to have the opportunity to present our position to you. Our position is that BART is a desirable recipient of power marketed by the Western Area Power Administration. However, the Draft Environmental Impact Statement, as written, has the potential of locking BART out of additional power allocations in 2004 and there after.

BACKGROUND

BART is a transit district created, organized and operated pursuant to Sections 28500 through 29757 of the California Public Utilities Code. It is governed by a nine member, publicly elected, Board of Directors.

BART began rapid transit operations in 1972 with, on average, 15,000 weekday passengers. Last year BART averaged more than 253,000 weekday passengers. In another two years weekday ridership is expected to exceed 283,000.

BART operates 34 passenger stations and 71 miles of track in the counties of Alameda, Contra Costa, San Francisco and San Mateo. 10 more passenger stations and 33 miles of new double track are under construction.

In addition to the rail network, feeder buses connect BART with Solano, Marin, and Santa Clara counties. BART also has weekday patrons from San Joaquin and Sonoma

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counties. All in all, BART regularly serves patrons in 9 counties.

This year BART will require approximately 59 megawatts of electric capacity to operate its system of which 4 megawatts will come from Western Area Power Administration (Western), Central Valley Project (CVP) beginning July 1st of this year. In the year 2004, when all present CVP contracts expire, BART will require approximately 100 megawatts of capacity.

BENEFITS TO PROVIDING CVP POWER TO BART

BART is an ideal recipient of Western power. BART provides an opportunity to make available to a broad spectrum of the public the economic benefits inherent in reclamation hydro-power. Unlike many of Western's customers whose services are confined to a single community, BART serves 15 communities directly and many more through connecting bus systems and express bus services. The number of communities served directly by BART will continue to expand as BART extends it system.

BART's electrically powered trains are clean air vehicles. Transferring riders from the cars to BART improves air quality. BART also mitigates traffic congestion, reduces the need for expensive highway expansions, provides affordable and efficient transit, and reduces the country's dependence on oil.

For BART's public, CVP power means lower electric costs. Lower electric costs mean lower fares. Lower fares mean greater ridership. Greater ridership means less traffic congestion and improved air quaility.

THE ENERGY PLANNING AND MANAGEMENT PROGRAM, ENVIRONMENTAL IMPACT STATEMENT (PROGRAM EIS) COULD BLOCK BART FROM RECEIVING ADDITIONAL CVP POWER IN POST-2004 ALLOCATIONS

It has been proposed that the Power Marketing Initiative (PMI) from the Program EIS be adopted by the CVP for post-2004 allocation. Alternatives 2-10 in the Draft Program EIS propose that Western customers receive between 90 and 100 percent of the available power resource when their contracts expire. If applied to the CVP, these alternatives will have the effect of locking-in present allocation of CVP power for the next 20 to 40 years.

It would seem imprudent for Western to establish a generic power allocation policy that locks in current allocations when Western does not know how much CVP power will be available to market and what entities will desire to purchase the power. In addition, implicit in the allocation of public power is the exercise of national energy policy and the adoption of environmental standards. Can Western ascertain today that current allocations will be in conformity with national policy and standards in place 20 to 40 years from now?

In addition the environmental analysis in the Draft Program EIS appears to conclude that retaining the existing allocation of power to Western customers is the best environmental option without analyzing the environmental effects of alternative power allocation regimes. For example, the Draft EIS does not consider the potential environmental benefits of increasing the future power allocations to certain customers. Increasing the allocation of CVP power to BART would reduce BART operating costs and, there by, lower fares. Lower fares increases ridership and thereby yielding a number of social benefits, including improved air quality.

ALTERNATIVE 12

Alternative 12 is the only alternative that gives Western the flexibility to respond to changes in National energy policy and environmental objectives, and allows for entities such as BART to participate in the Energy Management Initiative.

Alternatives 11-12 propose that Western make power allocation/contract extension decisions on a project-by-project basis as Western has done in the past. The difference between Alternatives 11 & 12 is that Alternative 12 provides a separate Integrated Resource Plan provision for small customers. Large utilities generally have a broad range of demand-side and supply-side measures available to them to improve efficiencies. End-use customers are usually limited to improving the efficiency of the end-use facilities. IRP compliance requirements should be sensitive to the potential benefits each customer would receive as well as the potential benefits to Western's system. It is quite possible for Western to set IRP requirements that when applied to end-users, have no real benefit to the customer or to Western's system, and, could actually discourage participation in Western's Marketing Program.

This concludes BART's comments. The District appreciates the opportunity to present this material and hopes that it will be helpful.

Mr. MILLER. Bruce, let me ask you a question. In your statement on page 10, under 3 there, you finished up by saying you recommend that Western refrain from committing anywhere near 100 percent of its resources. Instead, you recommend that Western consider committing now no more than 80 percent of resources available, after environmental analysis are complete, or 70 percent of existing resources.

How do you arrive at those figures?

Mr. DRIVER. There really isn't any magic number. I think I arrived at them as follows.

I considered all of the reasons why Western should be careful about the amount of the resource that they commit, by contract, to supply. They include the need to purchase sometimes environmentally damaging resources to firm the hydro resource that is, in part, related to how much resource they commit to supply in their contracts.

I considered the basic unfairness to potential new customers of extending all or a very high fraction of their resources.

I considered the fact that the utility industry is changing very rapidly, and in 10 to 15 years some of Western's existing customers may not even exist. There may be other customers that will come into being as a result of the breakup of the industry in the West.

I also considered the fact that Western may want to withhold some of its resource in order to reward those of its customers that do excellent work on demand-side management and IRP.

I thought about all those and I thought that anything between 90 and 100 percent seemed to be too much.

Now, very briefly, I was prepared to propose a higher fraction of the resource being made available if the base on which the extension is carried out is after environmental analyses are complete, or if the amount being made available is a percentage of the available resource down the line, rather than today's existing resource.

So I just came up with the figure of 80 percent for whatever turns out to be available after the analyses are done, and 70 percent——

Mr. MILLER. When you say 70 or 80, you are sort of considering one a gross and one a net figure if you had the proper environmental assessments; is that what you are saying?

Mr. DRIVER. Yes, that is exactly what I am saying.

Mr. MILLER. That does not take into account Native American claims?

Mr. DRIVER. It does. The 70 to 80 percent is the function of all the factors that I just enumerated.

Mr. MILLER. Let me ask, if I might, Mr. Paul Little—well, actually the three of you, Mr. Paul Little and Ms. Knight-Frank and Mr. Epperson—this issue of classification as a utility; you have each encountered this. This is the issue of utility status, having to acquire that to acquire the power.

As I look at it, my understanding is that is not a requirement of law; that is a requirement of Western that they have developed by regulation as a three-part test that they suggest for new customers. The one in the law is preference; is it not?

Mr. EPPERSON. Mr. Chairman, that is my understanding; that is not a requirement of law. My concern is that substantial weight seems to be given to that requirement, and it is one of informal standard.

Mr. MILLER. In the brief that the Oglalas have submitted, you still believe there needs to be a change in legislation, do you not? Am I reading that correctly?

Mr. LITTLE. Yes, Mr. Chairman.

Getting back to the issue of utility status, like I stated in my oral testimony, we went to Western and addressed all these issues of the Oglala Sioux Tribe and tribal members on the Missouri River Basin. It was always stated to us that we cannot accept new customers—you are not a utility status, you don't have utility status.

My answer to that, I opposed that. I think the tribe should be entitled to power that is generated off the Missouri River. As stated in the 1851 treaty, the tribe has water rights on the river.

Ms. KNIGHT-FRANK. Mr. Chairman, we have encountered the same thing. And we do have a plan of operation as it states in our written testimony. We are serious about this situation because of not being able to grow. We have enterprises. We are trying to be self-sufficient, and this is holding us back. And I think when we were just having a discussion with Mr. Barrett real briefly, we informed him we do own some of the lines on the reservation. Through the money we have been able to get through Congress for our irrigation project, we have built those utility lines, and we have an O&M agreement with Empire. So I think that is one of the things that may be of concern to them.

But I think the situation should really be looked at. We are capable of building those lines and doing the maintenance.

Mr. MILLER. I am just trying to determine if this is an artificial barrier or if this is a real barrier. Given both of your briefs and our reading, I am not quite sure this isn't an artificial barrier, this being thrown up.

Let me, Bruce, ask you another question. You raised the issue that it is one thing when Western looks down the line and asks what its customers are doing with respect to efficiency and environmentally sound practices with respect to renewables and what have you. It is not a question when they look up the line to see about purchasing.

I think what you are raising is whether they are purchasing to provide this power.

Mr. DeFazio suggested it may be easier for some customers to suggest that Western engage in that process, rather than themselves, and avoid the hassles or the problems there.

Mr. DRIVER. That is right. I would not think that SMUD, for example, would be looking to Western for leadership in terms of energy efficiency and the use of renewable resources. They are well ahead of what Western is doing. But many of Western's customers are quite small, and I think that Western really could provide a nice integration, if you will, function for them in terms of acquiring renewables and even acquiring energy efficiency from their own customers to firm up their own Federal hydroelectric resource.

Mr. MILLER. The Secretary has indicated that he is prepared to pursue that, so hopefully that will happen.

Let me thank you all very much for your testimony, and Ms. Knight-Frank, I think in your statement—I have read so many statements, I am getting confused—but you had pursued some actions, had you not, with the legislative delegation in terms of service? Had you not come to the congressional delegation to talk about this with your Senators?

Ms. KNIGHT-FRANK. Yes. We have pursued this for some time, and I think at first we were under the impression that we could do it, get it in on a bill, but we have been told that it has to be authorized.

Mr. MILLER. Right. You were looking at it in terms of a rider on the appropriations bills, as I understood it, and they said, we will take that under consideration and talk to the other Members of the committee that would be involved in that.

As I said earlier, I feel a very strong commitment that some of these issues be addressed on a rather timely basis because they have been hanging out there for a very, very long time. That is true with the Oglalas, also, on these issues. So we will get back to you on those.

Let me thank you very much for your help and for your testimony, and Bruce, for your work here. Thank you.

The committee stands adjourned.

[Whereupon, at 1:55 p.m., the subcommittee was adjourned.]

APPENDIX

JUNE 16, 1994

ADDITIONAL MATERIAL SUBMITTED FOR THE HEARING RECORD

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The Honorable Hazel R. O'Leary
May 25, 1994

which expire in 2008 (217 megawatts); and, the Boulder Canyon contracts i.e. Hoover Dam, which expire in the year 2017 (1,951 megawatts).

I am very concerned that these proposals to essentially lock-in current WAPA power allocations well into the next century will preclude this Administration and its successors from taking the steps necessary to make the WAPA power system responsive to the economic and environmental needs of the West in the coming decades. I also question both the wisdom and practicality of making power allocation decisions 10 to 23 years in advance of contract expiration dates when it is impossible to know how much power will be available at that time or who will seek allocations.

Furthermore, a generic WAPA policy regarding power allocation may not be appropriate because of the significant differences in the laws, policies, and problems relating to each water and power project that WAPA markets electricity from. A power allocation policy that works for the Pick-Sloan Missouri River system may not be workable for the Central Valley Project, and vice versa.

I also question the need to link power allocation and contract renewal to the integrated resource planning requirements established by Section 114 of the Energy Policy Act of 1992 (42 U.S.C §§ 7275-7276) (EPAct). WAPA officials have stated that linkage between IRP and contract extension is necessary to provide WAPA customers the certainty they need to conduct IRP and acquire new resources. While it is possible that WAPA contracts need to be extended earlier than they have been in the past in order to facilitate IRP (contracts for 543 megawatts of CVP power were renewed in 1992, 2 years before they expired), I am not convinced that utilities need to know what resources will be available from WAPA 15 to 40 years from now in order to guide their current resource acquisitions. No prudent utility in the United States is building new generation resources in 1994 to meet demand that it believes may arise in 2010 or 2035.

Finally, there is no basis in the legislative history of Section 114 for linking contract extension to IRP. Section 114 was the product of extensive bi-partisan negotiations and was supported by representatives of many WAPA customers, including the Colorado River Energy Distributors Association, the Northern California Power Agency and the National Rural Electric Cooperative Association. At no time during the consideration of Section 114 did any Member of this Committee or the House-Senate Conference Committee even propose to amend Section 114 to link IRP to contract extension.

I look forward to engaging in a constructive discussion with the Department at this hearing on the many issues that surround WAPA power allocation. Despite the very broad range of concerns I have about many of the proposals that WAPA is considering I

Page 3
The Honorable Hazel R. O'Leary
May 25, 1994

believe that it is possible to resolve these concerns in a manner that serves both the broader public interest and the particular interests of WAPA customers.

I have attached a series of questions that I request the Department respond to in its written testimony. Please fax or deliver an advance copy of your written testimony to the Subcommittee no later than Monday, June 13, 1994. The Subcommittee fax number is (202) 225-3554. Please also deliver 75 copies of your testimony to Room 1328 Longworth House Office Building no later than June 15, 1994. If your staff has any questions regarding the hearing please have them contact Mr. Dan Adamson (225-1911) or Ms. Linda Stevens (225-6042) of my staff.

Thank you for your consideration of this request.

Sincerely,

George Miller

GEORGE MILLER
Chairman
Subcommittee on Oversight
and Investigations

cc: The Honorable Bob Smith, Ranking Member,
Subcommittee on Oversight and Investigations

The Honorable William H. White, Deputy Secretary,
Department of Energy

Mr. William Clagett, Administrator,
Western Area Power Administration

DEPARTMENT OF ENERGY QUESTIONS
JUNE 16, 1994
HEARING ON WAPA POWER ALLOCATION

1. Can the Department of Energy predict with confidence the amount of hydroelectric power that will be available to market from the Loveland and Salt Lake City Projects in 2004, Parker-Davis in 2008, or Boulder Canyon in 2017? According to the Bureau of Reclamation's comments on the DEIS, "... insufficient information is available to Western to enable it to make a sound decision relating to contracts that will expire 10 years from now."

In light of the uncertainty surrounding the future availability of these resources, wouldn't it be prudent to defer these power allocation decisions to a later date?

2. The power allocation options in the WAPA DEIS all reserve between 90 and 100 percent of the available power resources for current WAPA customers. Is the reservation of such a large proportion of these resources for current customers prudent when it is impossible to determine what preference entities will be applying for power resources when contracts expire 10 to 20 years from now?

3. The general conclusion of the DEIS's environmental analysis appears to be that the more power WAPA reserves for current customers, and the longer the contract extension, the better the result for the environment because customers will utilize WAPA hydroelectricity instead of building their own fossil fuel-fired generation. However, this conclusion is based upon the inaccurate assumption that WAPA markets only hydroelectricity from federal dams and purchases no power.

Please provide, on WAPA-wide and project-by-project basis, estimates of the percentage of the electricity that WAPA has provided to its firm power customers in each of the last 5 years that is from fossil fuel-fired generation. Shouldn't the DEIS analyze the environmental effects of WAPA's purchase and sale of WAPA electricity that is produced from fossil fuels?

4. In the past, WAPA officials have stated that there needs to be linkage between IRP and contract extension in order to provide WAPA customers with the certainty they need to conduct IRP and acquire new resources. Amongst the alternatives analyzed in the DEIS is extending Loveland and Salt Lake City power contracts that expire in 2004 from 10 to 35 years. Therefore, under the various alternatives these particular contracts would be extended until at least 2014 and as long as until 2039.

Is it current utility practice to invest in supply or demand side resources for electricity needs that may exist 20 years from now (2014) or 45 years from now (2039)? If not, is it necessary to act now to extend contracts for the purpose of facilitating IRP?

5. In its comments on the DEIS, the Bureau of Reclamation states:

> Reclamation is concerned that the power contract extension alternatives proposed by Western may create unrealistic expectations regarding future power allocations amongst Western customers, which may be difficult to satisfy in the event of future changes in the operations of Reclamation Dams. The recent controversy regarding changes in Glen Canyon Dam operations demonstrated that although Reclamation retains control over dam operations, the expectations of Western, and its customers, that a certain amount of power will be produced by a dam make it much more difficult for Reclamation to exercise its discretion to modify dam operations.

In light of the Bureau's concerns about the environmental consequences of creating unrealistic expectations of future power allocations, is it prudent for WAPA to make power allocations decisions in 1994 for contracts that will expire 10 (Loveland, Salt Lake City) to 23 years (Hoover) from now?

6. The DEIS only considers power allocation options that involve reserving between 90 and 100 percent of the available power resource for WAPA customers. The DEIS does not analyze the environmental effects of any alternative power allocation regimes, including the following:

- providing power to preference entities that do not currently receive WAPA power such as Indian tribes and others;
- increasing the power provided for the pumping of water for fish and wildlife purposes; and,
- increasing the power allocations of WAPA customers who maximize the environmental benefit of their current allocations through energy efficiency and other measures.

Shouldn't the DEIS be modified to analyze these alternatives?

7. What is the contract length for current Pick-Sloan, Loveland, Salt Lake City, Central Valley Project and Parker-Davis contracts? How far in advance of the expiration of previous contracts were these current contracts signed?

U.S. House of Representatives
Committee on Natural Resources
Washington, DC 20515-6201

June 17, 1994

The Honorable William H. White
Deputy Secretary
Department of Energy
1000 Independence Ave, S.W.
Washington, D.C. 20585

Dear Mr. White:

Thank you very much for your June 16, 1994, testimony before the Subcommittee regarding the Western Area Power Administration (Western). I commend you for your willingness to engage yourself in the many important issues facing this agency. Your testimony outlined the most substantial program for reform of Western policies ever presented by a federal official. I look forward to working together with you on the implementation of these reforms.

Attached are questions that I request that the Department respond to for the record. I would appreciate receiving these responses by July 1, 1994. I may submit additional questions to the Department in the coming weeks.

Thank you for your consideration of this request.

Sincerely,

George Miller

GEORGE MILLER
Chairman
Subcommittee on Oversight
and Investigations

cc: The Honorable Bob Smith, Ranking Member,
Subcommittee on Oversight and Investigations

Mr. William Clagett, Administrator
Western Area Power Administration

DEPARTMENT OF ENERGY QUESTIONS
FOR THE RECORD
HEARING ON WAPA POWER ALLOCATION
JUNE 16, 1994

1. There is no requirement in either statute or case law that bars Western from marketing power to preference entities that are not utilities. Western sells a considerable amount of power to end-users, particularly State and federal installations. Western has a great deal of discretion in defining what a preference entity is because the Reclamation Project Act of 1939 requires only that "public entities" shall be favored when Western allocates power. City of Santa Clara, California v. Andrus, 572 F.2nd 660 at 667, (9th Cir. 1978). In fact, Congress has expressed no intent on the question of whether preference entities must have "utility responsibility." Salt Lake City, et. al. v. Western Area Power Administration, 926 F.2nd 974 at 978, (10th Cir. 1991).

Western's EPMP DEIS would limit new customers to those with "utility status" (p. 11, DEIS) and Deputy Secretary White's testimony stated that Western supported allocating power to "Native American utilities and other eligible preference entities."(p. 19) Is it the Department's policy to only provide allocations of Western power to new preference customers with "utility status"? Will the Department direct Western to amend the EPMP EIS so that allocation to new preference customers such as Native American tribes that do not have "utility status" will be considered?

2. In my view, a project specific EIS process can far more accurately gauge the environmental and economic impacts of allocation/contract extension decisions and also provides the citizens of the project areas with far more input than the EPMP EIS. For example, a number of preference entities that are interested in receiving Western power allocations, including Native American tribes, were unaware that the EPMP DEIS might affect their ability to receive power from Western in the future until they were contacted by my office. In addition, project specific EISs will make it much easier for Western to coordinate its efforts with the power generating agencies, the Bureau of Reclamation and Corps of Engineers.

Western has initiated separate EISs concerning allocation/contract extension of Central Valley Project (CVP) and Salt Lake City Area Integrated Projects (SLCA) power post-2004 when current contracts expire. Will these project specific EIS's be the NEPA decision document for the allocation/contract extension of CVP and SLCA power post-2004 rather than Energy Planning and Management Program (EPMP) EIS?

3. Will the Department direct Western to conduct a project specific EIS regarding allocation/contract extension of the Loveland Area Projects contracts which expire in 2004? If not, please explain the basis for this decision.

4. Deputy Secretary White's written Subcommittee testimony stated that 10 year power contracts were too short and 40 year contracts were too long. (p. 4) Since Western was created the majority of power contracts it has signed have been for 15 or 10 years, including Pick-Sloan (1,656 MW), SLCA (1,398 MW), Loveland (693 MW), and a portion of CVP (539 MW). One set of 21 year contracts have been signed for Parker-Davis (217 MW) and Congress statutorily directed Western to sign 30 year contracts in the Hoover Power Plant Act of 1984 for the Boulder Canyon Project (1,951 MW). Typically, Western has renewed contracts 2 to 5 years in advance of contract expiration dates.

The Pick-Sloan contracts will expire first, in the year 2000, so I assume that the Department will be making a decision in the near term regarding the length of this extension. Will the Department direct Western to extend Pick-Sloan contracts for no longer than 15 years, which is the length of the current Pick Sloan contracts?

5. The Subcommittee has longstanding concerns regarding the unauthorized construction of transmission lines by Western. A recent example of this problem is the proposed Navajo Transmission Project (NTP), a 400-mile 500-kv transmission line between the Four Corners area of New Mexico and the Las Vegas, Nevada area, which is expected to cost over $320 million. I have requested that no Western funding be made available for this project in Fiscal Year 1995, because NTP has not been authorized by the Natural Resources Committee. Consistent with this request, Western's funding request for NTP was denied in the FY 1995 Energy and Water Appropriations bill as passed by the House.

Questions have been raised recently regarding the NTP by both Western customers and environmentalists. The Colorado River Energy Distributors Association (CREDA), which represents WAPA Colorado River Storage Project (CRSP) customers who pay through their power rates for Western expenditures on the NTP, has stated that they are being asked to pay for more than their fair share of this project. According to CREDA, only about 8 percent of the capacity of this line would be used for purposes related to CRSP, yet CREDA members through Western, have already paid for 25 percent of the total estimated costs for NTP studies and pre-construction activities.

Two environmental groups, the Land and Water Fund of the Rockies (LAW Fund) and the Natural Resources Defense Council (NRDC), have also raised questions regarding the NTP. According to these groups, the NTP would adversely affect the Southwest environment because it would encourage increased generation of electricity from coal and discourage the use of more environmentally benign sources of electricity such as energy efficiency.

The LAW Fund/NRDC has also pointed out that Western's decision to participate in the NTP was made without the benefit of any systematic study of the need for the line or the potential impacts it might have. This criticism is bolstered by the fact that Western's estimates of the amount of capacity it would use on the line have changed considerably over the last year. In 1993, WAPA planned to use up to 40 percent of the NTP to transmit CRSP power. Recently, Western has stated that its participation in the line will be "no more than" 20 percent, which is substantially higher than the 8 percent estimate arrived at by Western customers.

NTP is, at best, an example of the serious flaws in Western's decisionmaking process for pursuing transmission line investments. One way for Western to avoid a repeat of the NTP fiasco would be to apply integrated resource planning principles to transmission investments. During informal discussions with my staff, WAPA officials have stated that the NEPA EIS process is the best forum for addressing these questions. I strongly disagree. Fundamental questions about the need for a transmission investment should be answered, based on available information, before millions of dollars are spent on an EIS.

Will the Department direct Western to apply integrated resource planning principles and processes to the agency's investments in new and upgraded transmission lines?

Department of Energy
Washington, DC 20585

July 12, 1994

The Honorable George Miller
Chairman
Subcommittee on Oversight and Investigations
Committee on Natural Resources
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

On June 16, 1994, William H. White, Deputy Secretary of Energy, testified regarding Western Area Power Administration's policies.

Enclosed are the answers to the five questions submitted by you to complete the record.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Very truly yours,

William J. Taylor, III
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTIONS FROM CHAIRMAN GEORGE MILLER

Question 1: There is no requirement in either statute or case law that bars Western from marketing power to preference entities that are not utilities. Western sells a considerable amount of power to end-users, particularly State and federal installations. Western has a great deal of discretion in defining what a preference entity is because the Reclamation Project Act of 1939 requires only that "public entities" shall be favored when Western allocates power. City of Santa Clara, California v. Andrus, 572 F.2nd 660 at 667, (9th Cir. 1978). In fact, Congress has expressed no intent on the question of whether preference entities must have "utility responsibility." Salt Lake City, et. al. v. Western Area Power Administration, 926 F.2nd 974 at 978, (10th Cir. 1991).

Western's EPMP DEIS would limit new customers to those with "utility status" (p. 11, DEIS) and Deputy Secretary White's testimony stated that Western supported allocating power to "Native American utilities and other eligible preference entities."(p. 19) Is it the Department's policy to only provide allocations of Western power to new preference customers with "utility status"? Will the Department direct Western to amend the EPMP EIS so that allocation to new preference customers such as Native American tribes that do not have "utility status" will be considered?

Answer: Western will not require utility responsibility for all new preference power customers receiving allocations of Federal Power. Many Federal agencies, including DOE installations, have enjoyed preference status, as end users, even though they have no utility responsibility. DOE plans no change in the status of such Federal agencies. However, it is Western's policy to give preference in allocating power to municipalities that have utility responsibility. A recent court opinion found Western's interpretation of Congressional intent supporting this policy for municipalities to be "fully reasonable." Salt Lake City, et al. v. Western Area Power Administration, et al., No. C86-1000G (C.D. Utah Apr. 14, 1989), slip op. at 40, aff'd, 926 F.2d 974, 978 (10th Cir. 1991).

As for Native American Tribes, the Bureau of Reclamation concluded in 1961 that the Navajo Tribe qualified as a preference customer under § 9(c) of the Reclamation Project Act of 1939. Western has always considered Native American Tribes as preference entities. Proposals for providing allocations directly to Native American Tribes will be developed on a project-by-project basis, during the allocation of project-specific resource pools. This flexibility is critical since an allocation of power is of no value unless an organization has the means to receive power; the potential customer must be ready, willing and able to take delivery of power. If resource pools are part of the proposed EPAMP rule, they will be sized to include proposed allocations to Native American Tribes.

Many Native Americans receive hydroelectric power benefits from Western today. Western has directly allocated power to tribal utilities or tribal irrigation districts. Western also has allocated power to cooperatives that, in turn, serve many tribal loads. Lower electrical rates are paid by tribes served by utilities receiving power from Western. Either directly or indirectly, Western's allocations benefit 45-50 tribes throughout the west. In the Eastern Division of the Pick-Sloan Missouri Basin Program, Western estimates that approximately 30 percent of the total Native American load on tribal reservations is met through Western allocations of power to cooperatives serving these reservations.

The page in the draft EIS referenced by the Chairman's question will be expanded to clarify Western's policy.

Question 2:

In my view, a project specific EIS process can far more accurately gauge the environmental and economic impacts of allocation/contract extension decisions and also provides the citizens of the project areas with far more input than the EPMP EIS. For example, a number of preference entities that are interested in receiving Western power allocations, including Native American tribes, were unaware that the EPMP DEIS might affect their ability to receive power from Western in the future until they were contacted by my office. In addition, project specific EISs will make it much easier for Western to coordinate its efforts with the power generating agencies, the Bureau of Reclamation and Corps of Engineers.

Western has initiated separate EISs concerning allocation/contract extension of Central Valley Project (CVP) and Salt Lake City Area Integrated Projects (SLCA) power post-2004 when current contracts expire. Will these project specific EIS's be the NEPA decision document for the allocation/contract extension of CVP and SLCA power post-2004 rather than Energy Planning and Management Program (EPMP) EIS?

Answer:

Western has initiated an environmental impact statement process regarding the marketing of power from the Central Valley Project (CVP) and the Washoe Project after existing contracts expire in the year 2004. The CVP 2004 marketing plan EIS will be the National Environmental Policy Act (NEPA) decision document for future allocations/contract extensions in northern California.

The Energy Planning and Management Program EIS will not be the final NEPA decision document for the Salt Lake City Area Integrated Projects (SLCA/IP) after existing contracts expire in 2004. Western will not extend any SLCA/IP resources beyond 2004 until the ongoing marketing plan EIS, the marketing plan itself, and associated contract changes are complete. Additional project-specific environmental documentation will be needed before decisions can be made on such important issues as the resource to be marketed after existing contracts expire, allocations to new customers, and the size of a resource pool. Whether the necessary environmental documentation would rise to the level of an environmental impact statement depends upon the issues, public interest, and controversy that exist when these questions are addressed at a time closer to the expiration date of existing contracts.

Western's ongoing project-specific environmental impact statement for the SLCA/IP analyzes power marketing between now and the year 2004. Since no decision has been made on current resource commitments, it is premature to address the marketing of power after current contracts expire.

Question 3: Will the Department direct Western to conduct a project specific EIS regarding allocation/contract extension of the Loveland Area Projects contracts which expire in 2004? If not, please explain the basis for this decision.

Answer: The Energy Planning and Management Program EIS may be the final NEPA decision document for the marketing of power from the Loveland Area Projects (LAP) after existing contracts expire in 2004. The existing contracts require a review of the marketable resource and, if required, an adjustment to the current firm power commitments in 1999. If environmental concerns are identified during the adjustment process, additional project-specific environmental documentation may be required. Public processes and environmental documentation will also be required before final decisions are made on allocations to new customers and the size of the LAP resource pool.

Question 4: Deputy Secretary White's written Subcommittee testimony stated that 10 year power contracts were too short and 40 year contracts were too long. (p. 4) Since Western was created the majority of power contracts it has signed have been for 15 or 10 years, including Pick-Sloan (1,656 MW), SLCA (1,398 MW), Loveland (693 MW), and a portion of CVP (539 MW). One set of 21 year contracts have been signed for Parker-Davis (217 MW) and Congress statutorily directed Western to sign 30 year contracts in the Hoover Power Plant Act of 1984 for the Boulder Canyon Project (1,951 MW). Typically, Western has renewed contracts 2 to 5 years in advance of contract expiration dates.

The Pick-Sloan contracts will expire first, in the year 2000, so I assume that the Department will be making a decision in the near term regarding the length of this extension. Will the Department direct Western to extend Pick-Sloan contracts for no longer than 15 years, which is the length of the current Pick Sloan contracts?

Answer: Western is developing a proposed Energy Planning and Management Program rule based upon the numerous comments received during the public process. Based upon the record that has been established, a term of contract will be included in the proposed rule. Additional public comment will then be sought before a final rule is developed and the final environmental impact statement is prepared. To protect the integrity of the public process, no decision on the term of contract will be made public prior to publication of the proposed rule. However, I can assure you that this important issue will receive my personal attention before any proposals or decisions are made.

Question 5: The Subcommittee has longstanding concerns regarding the unauthorized construction of transmission lines by Western. A recent example of this problem is the proposed Navajo Transmission Project (NTP), a 400-mile 500-kv transmission line between the Four Corners area of New Mexico and the Las Vegas, Nevada area, which is expected to cost over $320 million. I have requested that no Western funding be made available for this project in Fiscal Year 1995, because NTP has not been authorized by the Natural Resources Committee. Consistent with this request, Western's funding request for NTP was denied in the FY 1995 Energy and Water Appropriations bill as passed by the House.

Questions have been raised recently regarding the NTP by both Western customers and environmentalists. The Colorado River Energy Distributors Association (CREDA), which represents WAPA Colorado River Storage Project (CRSP) customers who pay through their power rates for Western expenditures on the NTP, has stated that they are being asked to pay for more than their fair share of this project. According to CREDA, only about 8 percent of the capacity of this line would be used for purposes related to CRSP, yet CREDA members through Western, have already paid for 25 percent of the total estimated costs for NTP studies and pre-construction activities.

Two environmental groups, the Land and Water Fund of the Rockies (LAW Fund) and the Natural Resources Defense Council (NRDC), have also raised questions regarding the NTP. According to these groups, the NTP would adversely affect the Southwest environment because it would encourage increased generation of electricity from coal and discourage the use of more environmentally benign sources of electricity such as energy efficiency.

The LAW Fund/NRDC has also pointed out that Western's decision to participate in the NTP was made without the benefit of any systematic study of the need for the line or the potential impacts it might have. This criticism is bolstered by the fact that Western's estimates of the amount of capacity it would use on the line have changed considerably over the last year. In 1993, WAPA planned to use up to 40 percent of the NTP to transmit CRSP power. Recently, Western has stated that its participation will be "no more than" 20 percent, which is substantially higher than the 8 percent estimate arrived at by Western customers.

NTP is, at best, an example of the serious flaws in Western's decisionmaking process for pursuing transmission line investments. One way for Western to avoid a repeat of the NTP fiasco would be to apply integrated resource planning principles to transmission investments. During informal discussions with my staff, WAPA officials have stated that the

NEPA EIS process is the best forum for addressing these questions. I strongly disagree. Fundamental questions about the need for a transmission investment should be answered, based on available information, before millions of dollars are spent on an EIS.

Will the Department direct Western to apply integrated resource planning principles and processes to the agency's investments in new and upgraded transmission lines?

Answer: Western will use applicable integrated resource planning (IRP) principles and processes in its transmission planning. Use of IRP principles and processes would be beneficial to Western's ratepayers by assuring that investments are cost-effective. Environmental benefits also could result as Western evaluates transmission in accordance with IRP principles.

I agree that fundamental questions about the need for a transmission line investment should be answered before millions of dollars are spent on an EIS. However, application of IRP principles during the transmission line EIS process offers an opportunity for analysis of the character of generation to be transmitted, an opportunity that may not exist at an earlier stage in the planning process. Alternative routes for transmission lines would not be determined until the scoping process is complete. The location of a transmission line may influence the type of resource that would be transmitted over that line. One alternative may result in fossil-fuel thermal plant generation, while other routes may encourage operation of a natural gas-fired turbine or development of renewable resources.

Use of IRP principles in Western's transmission planning is reflected in decision rules recently adopted by Western as part of its strategic planning process. Proposals for construction of new facilities and, as appropriate, significant upgrades of existing facilities will be assessed using IRP principles. In addition, the proposals must pass at least one of the three following criteria before Western will consider construction: 1) increased revenues from the new facilities must exceed the annual cost over the first five years of service; 2) customers must benefit sufficiently to support the new facilities in spite of a possible rate increase; or 3) the new facilities will be funded by others. Western will also continue to engage in regional transmission planning with other entities and pursue joint participation in transmission line planning and construction whenever possible.

I would be pleased to respond to specific concerns of the Subcommittee on Western's transmission line construction program. The following information is provided to the Committee in regard to the concern raised about Western's construction program. In establishing Western in 1977, Congress transferred to the Secretary of Energy:

> the power marketing functions of the Bureau of Reclamation, including the construction, operation, and maintenance of transmission lines and attendant facilities; . . . .

§ 302(a)(1)((E), Department of Energy Organization Act, 42 U.S.C. §7152. When Utah Power and Light Company challenged

Western's participation in construction of the Craig-Bonanza transmission line, the Tenth Circuit cited this section in holding that:

> Congress has authorized WAPA, as an agency within the Department of Energy, to engage in the construction of the Craig-Bonanza transmission line. . . Congress has granted WAPA broad authority to construct transmission lines.

Salt Lake City, et al. v. Western Area Power Administration, et al., 926 F.2d 974, 983 (10th Cir. 1991). In response to a 1987 inquiry from the House Subcommittee on Water and Power Resources, the Comptroller General reached a similar conclusion in finding that Western had authority to construct the Tracy Tie Line to Lawrence Livermore National Laboratory. "Federal Electric Power: Western Area Administration's Tracy/Livermore Transmission Project," GAO/RCED-88-19 (Oct. 1987).

Western Area Power Administration

Energy Planning and Management Program

Draft

Environmental Impact Statement

Summary

The Western Area Power Administration (Western) is an agency of the U.S. Department of Energy charged with marketing and transmitting Federally produced electricity throughout a 1.3 million-square-mile geographic area. The majority of this electricity comes from federally owned and operated hydroelectric plants. Western's service region represents the largest geographic area served by a Federal power marketing agency. It covers 15 States from Minnesota in the northeast to California in the southwest. The organization is headquartered in Golden, Colorado. Western's five area offices are in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; Sacramento, California; and Salt Lake City, Utah.

Western proposes to establish an Energy Planning and Management Program (the Program) to replace its Guidelines and Acceptance Criteria (G&AC) for the Conservation and Renewable Energy (C&RE) Program and to evaluate ways to make future resource commitments to existing customers. If adopted, the proposed Program would require Western's long-term firm customers to implement long-term energy planning to help enhance efficient electric energy use. The proposed Program could link Western's power resource allocations to customer programs for long-term energy planning and efficient electric energy use, or Western could continue to market power on a project-specific basis in the future.

Legislation specifically authorizing Western's C&RE Program was included in Title II of the Hoover Power Plant Act of 1984 (42 U.S. Code [USC] 7275-7276). After this legislation was passed, an amendment to the G&AC was issued on August 21, 1985 (50 Federal Register [FR] 33892). The amended Program is described in Chapter 2, Alternatives.

A review of Western's amended G&AC, initiated by 17 public meetings held throughout Western's service area in the spring of 1990, indicated that it could be measurably improved by strengthening some provisions and incorporating a more comprehensive approach than that currently taken by Western's C&RE program. Western also is facing the expiration of many of its long-term firm power contracts over the next several years. These contracts present an opportunity to restructure Western's marketing approach to facilitate long-term energy management planning by Western's customers. On April 19, 1991, Western formally proposed the Program, which featured linkage of Western's power resource allocations with long-term energy planning and Western's customers' efficient energy use through the preparation of integrated resource plans (IRPs) (56 FR 16093). Western also provided notice to the public of its intention to prepare an environmental impact statement (EIS) on the Program (56 FR 19995 [May 1, 1991]). Western has developed the Program through an extensive public participation process, including 38 public meetings and workshops and distribution of a series of Program newsletters.

On October 24, 1992, the Energy Policy Act of 1992 (the Act) (Public Law No. 102-486) was signed into law. Section 114 of the Act amends Title II of the Hoover Power Plant Act of 1984. The new legislation requires Western's customers to prepare and implement IRPs. Changes to Western's proposed Program resulting from passage of the legislation include an adjustment to the penalty provision and a requirement that Western penalize customers not acting in accordance with their IRPs. Much of this legislation is consistent with Western's ongoing administrative development of the Energy Planning and Management Program. This draft EIS recognizes and incorporates the Act into the Program.

Section 114 of the Energy Policy Act of 1992 specifies that the National Environmental Policy Act

of 1969 (NEPA) shall apply to the Administrator's actions implementing integrated resource planning. This EIS will fulfill that mandate.

Western must place its resources under contract to fulfill its mission as a power marketing administration, to repay each project's debt, and to provide its customers with resource certainty. Western's utility customers have the responsibility to meet the electricity needs of their consumers, which means the utilities must guarantee electric service. Quality utility planning is enhanced when a customer's existing power resources are stable and reliable. To be considered a stable and reliable part of a customer's existing resources, Western's power allocation must be secure over a time frame typical of long-term firm power sales and purchases in the utility industry.

Currently, Western markets its resources through independent marketing plans that are specific to the Federal power projects in Western's service region. Under the proposed Program, rates would continue to vary from project to project reflecting project costs, but the Program Alternatives contain some contract provisions that would be consistent across Western. Contractual provisions outside of the Program would continue to vary on a project-specific basis.

The two parts of the proposed Program are the Power Marketing Initiative (PMI) and the Energy Management Program (EMP). Under the proposed PMI, three different groups of alternatives have been developed. All of the alternatives, except the No-Action Alternative, include the penalty provision of the Energy Policy Act of 1992. The groups of PMI options considered in this EIS are:

- **PMI Extension Alternatives** - The first group, known as the PMI extension alternatives, would give Western's existing customers relatively long-term extensions of a major percentage of the Federal power resource currently committed to them subject to certain provisions. These provisions include the percentage of the allocation, the term of the contracts, establishment of a resource pool, and the manner in which the pool would be used. Contracts for resource extensions would be signed upon receipt of a customer's initial IRP by Western.
- **PMI Limited Extension Alternatives** - The second set, known as the PMI limited extension alternatives, would extend resources for 10 years from the date of IRP approval, a relatively short time period. This short extension period is intended to provide Western's existing long-term firm power customers with a term adequate to facilitate the development of an IRP and effectuate associated action plans. The extension would act as a bridge to give Western time to develop project-specific marketing plans and the customers time to develop and implement alternative resources in reaction to any change of marketable resources as identified in the project-specific marketing plan. Contracts for resource extensions would be signed upon approval of a customer's initial IRP by Western.
- **PMI Non-Extension Alternatives** - The third set, known collectively as the PMI non-extension alternatives, would not feature any marketing of resources under the proposed Program. Customer integrated resource planning would take place in accordance with the Energy Policy Act of 1992, and marketing criteria would be separately developed on a project-specific basis.

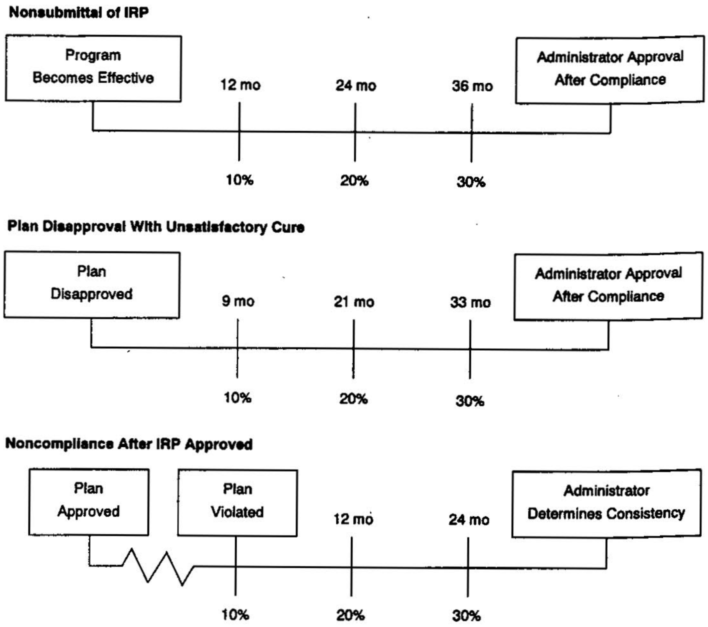
The proposed EMP would require each customer to establish an energy management program, which would be applicable to all customer power resources and not just the Western allocation. Customer activities that may fall under the Program Alternatives (see Chapter 2) include IRP or activities appropriate for certain small customers with limited resources. Tables S.1 and S.2 summarize the various EMP and PMI components and describe how they fit into the alternatives.

Potential Program components have been combined to form 12 alternatives, including a No-Action Alternative, based on existing Program features.

Table S.3 summarizes the 12 alternatives.

A number of issues were raised during the scoping process that were determined to be outside the scope of this draft EIS. Examples of these issues include transmission access, incentive rates and rate design modifications by Western, and river and dam operations. A discussion of these issues can be found in Section 2.2.

FIGURE S.1. Surcharge Penalty Provisions of the Energy Policy Act of 1992(a)



(a) Congress has provided for a graduated rate surcharge on all power purchased from Western—not just firm power—or a 10% reduction in a power commitment, unless a customer has made a good faith effort to comply.

TABLE S.1. Summary of the EMP Components Considered by Western

EMP Components	
Integrated Resource Plan	IRP required for some or all customers. IRP is a process where supply-side and demand-side resource options are consistently evaluated together to determine how to serve the electricity needs of consumers at the lowest reasonable cost.
Other Planning Options	IRP required for most customers, but Western would establish different regulations for certain small customers with total energy sales or usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility. These customers shall consider all reasonable opportunities to meet future energy services requirements using demand-side techniques, new renewable resources, and other programs that provide retail customers with electricity at the lowest possible cost, and minimize, to the extent practicable, adverse environmental effects (Energy Policy Act of 1992).

TABLE S.2. Summary of the PMI Components Considered by Western

PMI Components	
Extension Period	10, 15, 25, or 35 years, or on a project-specific basis
Percentage Extension	90%, 95%, 98%, or 100% of marketable resource; adjustment due to operational changes possible; adjustment only after an appropriate consultation process.
Resource Pool	10% (provides support of existing customer development of new C&RE technologies), 5%, or 2% for new customers/contingencies. No resource pool for some alternatives.
Resource Adjustment Provisions	Tied to extension period; none for some alternatives; limited if contract extension is 15 years; one adjustment if extension is 25 years; two if extension is 35 years, project use adjustments are based on existing contract principles. One alternative would include adjustments on 5 years' notice for limited purposes.
Penalty	All alternatives contain the penalty provisions prescribed in the Energy Policy Act. These provisions call for a 10% surcharge for nonsubmittal after 1 year from new rule adoption, or when customers fail to comply with approved plans; or after 9 months for failure to submit after the Administrator disapproves a plan; 20% surcharge after second year of noncompliance; 30% surcharge in third year of noncompliance. This time line is illustrated in Figure S.1. The Act also allows for a 10% power reduction as an optional penalty.

TABLE S.3. Summary of Energy Planning and Management Program Alternatives

Program Component	No Action	Program Alternatives: PMI Extension							PMI Limited Extension		PMI Non-Extension	
	1	2	3	4	5	6	7	8	9	10	11	12
EMP	C&RE G&AC	IRP	IRP	IRP	IRP with Small Customer Provision	IRP with Small Customer Provision	IRP with Small Customer Provision	IRP	IRP	IRP with Small Customer Provision	IRP	IRP with Small Customer Provision
Extension Period	varies [a]	15 yrs [b]	25 yrs [b]	35 yrs [b]	15 yrs [b]	25 yrs [b]	35 yrs [b]	25 yrs [b]	10 yrs [c]	10 yrs [c]	varies [a]	varies [a]
Percentage Allocation	varies [a]	98%	95%	90%	98%	95%	90%	98%	100% [e]	100% [e]	varies [a]	varies [a]
Resource Pool	none [d]	2%	5%	10%	2%	5%	10%	2%	none [e]	none [e]	none [d]	none [d]
Adjustment Provisions	none [d]	limited	1 adjust.	2 adjust.	limited	1 adjust.	2 adjust.	5 yr notice	none	none	none [d]	none [d]
Penalty Provision	10% Withdrawal	10% to 30% surcharge, see Figure 2.1 and Table 2.4 Optional 10% power reduction										

[a] To be determined by project-specific marketing plan.

[b] Contract extension begins at time of current contract expiration. Contracts are executed upon receipt of IRP by Western.

[c] Contract extensions are executed at the time of IRP approval; extension will provide resource certainty to a customer for 10 years from the date of IRP approval. After 10 years, power marketing will be determined by project-specific marketing plans.

[d] Unless provided by project-specific marketing plan.

[e] Western assumes that the percent allocation after the limited extension period will be determined by project-specific marketing plans. For purposes of analysis, this Draft EIS assumes a 90% allocation after the expiration of the 10-year extension period.

S.1 PHYSICAL ENVIRONMENTAL IMPACTS

The environmental analysis of the alternatives fully analyzes those impacts that are predictable without knowing the specific locations that would be affected. For example, the quantity of air pollutants that may be emitted under each of the alternatives is estimated. As specific actions are established, detailed environmental analyses would be developed by those initiating the projects as required by State and Federal legislation.

The environmental analysis involves the straightforward approach of multiplying an environmental impact factor by the generation or capacity associated with energy resources deployed under each of the alternatives. The result is an estimate of certain environmental impacts such as air emissions or solid waste production. The capacity and generation projections were modeled for each of Western's area offices.

The electricity generation modeling in Western's service region showed relatively slight differences among the Program Alternatives as compared to the No-Action Alternative, which resulted in more generation. Along with capacity additions of power plants, which were also found to be greater under the No-Action Alternative, these differences in generation result in the potential environmental impacts summarized in this section. Conservation activities resulting from energy planning dominated those changes caused by the PMI provisions. This difference in electricity demand results in the prominent difference between the No-Action Alternative and the Program Alternatives. Uncertainty arising from varying contract lengths and percentage extensions causes some variation among the Program Alternatives.

In all of the areas, the predicted customer response to the Program reduced energy usage by roughly 2 percent to 6 percent in the year 2015. Western's customers are forecast to use 5 percent to 15 percent less energy in the year 2015; this represents about 13.4 billion kilowatt hours in reduced usage by Western's customers in the year 2015, the equivalent of about 45 percent of the firm energy that Western markets today. The Phoenix and Sacramento areas were projected to experience less reduction because a substantial amount of conservation activity already exists there and is contained in the No-Action Alternative. Billings, Loveland, and Salt Lake City, where energy-efficient buildings make up a smaller portion of building stock, are predicted to have larger potential savings.

Table S.4 summarizes environmental and planning information for the generation portion of the fuel cycle. The information is generic in nature; it does not apply to any particular plant, but rather represents a range of plants or calculated values. The resources included in the model for potential growth in generation capacity over the next 20 years are coal-fired power plants, gas-fired simple-cycle combustion turbines, gas-fired combined-cycle combustion turbines, hydroelectric plants, and other renewables using wind and geothermal technologies. Resources that were not modeled are included in the table to allow for comparison.

As specific resources are chosen, additional environmental analyses will be necessary. Western will complete these analyses for the resources that the agency initiates, if any. Most, if not all, of the resources will be proposed and built by individual utilities or utility-based associations. For these non-Federal projects, environmental analysis and documentation will come in the form of siting, discharge, and use permits issued by local, state, and Federal agencies. Federal permits may require NEPA documentation, which will be determined by the issuing agency.

Table S.3 summarizes the salient provisions of the 12 alternatives. All Program Alternatives would have less adverse environmental impacts and neutral economic impacts compared to the No-Action Alternative. The impacts of the Program Alternatives show relatively slight differences among them. Only the No-Action Alternative has substantially different impacts. Tables S.5 and S.6 show total potential impacts and indicate how much the impacts of each alternative differ from those of the No-Action Alternative.

The findings from the analysis presented in this draft EIS suggest that, in comparison with the No-Action Alternative, any of the Program Alternatives would result in fewer environmental impacts over time. When compared to emissions of the entire utility industry in Western's service region, these reductions appear small. However, in absolute terms, the reductions are important. For example, a typical 500-MW coal plant produces 2,600 tons of sulfur oxides (SO_X), 5,200 tons of oxides of nitrogen (NO_X), 500 tons of total suspended particulates (TSP), and about 3.2 million tons of carbon dioxide (CO_2) annually. The Program Alternatives would reduce annual emissions by about the equivalent of one and one-half to two coal plants in 2015. A similar comparison with natural gas-fired simple cycle combustion turbines results in offsetting about 11 to 14 250-MW units when SO_X is ignored. Natural gas combustion turbines produce little SO_X in comparison with coal plants.

A summary of estimated impacts for the year 2005 is shown in Table S.5. Estimates for the year 2015 are shown in Table S.6. The table shows relatively little distinction among the Program Alternatives. The variation that does occur is associated with the percentage extension of Western firm power included in each alternative, and the uncertainty confronted by Western's customers in response to varying contract extension periods.

Several general trends are apparent from the analysis. First, all Program Alternatives would tend to result in fewer adverse impacts in comparison to the No-Action Alternative. This trend is true for all of the physical environmental impacts analyzed and most of the economic impacts, and can be attributed to increased customer investment in demand-side resources instead of power plant construction. One exception is short-term rate impacts, which rise slightly to pay for planning activities (see Section 4.10.2). However, in the long-term, rates would tend to be reduced as utilities use resources more efficiently. Two analytical techniques were used to assess regional employment and effects on trade and commerce. Taken together, these analyses show neutral to positive effects resulting from the Program Alternatives (see Section 4.9).

Another trend is identifiable in the relationship between environmental benefits and the certainty of Western's power commitments. For most environmental impacts identified in the analysis, benefits to the environment are predicted when relatively high percentages of assured Western resources are extended. The Non-Extension Alternatives are consistently less beneficial to the environment than other Program Alternatives across all impact categories. The Limited Extension Alternatives result in a similar pattern as compared to the Extension Alternatives featuring an assured, high-percentage extension of existing resources. This trend is attributable to relatively higher levels of plant construction and electricity generation by existing customers in reaction to uncertainty in Western's commitments.

The third trend is true of all of the alternatives and is seen in the quantities of impacts over time. Impacts that are tied to coal combustion, such as SO_X emissions and ash production, tend to peak in the year 2005, then decline or remain constant. This trend mirrors the quantity of electricity generated from coal plants. Between 1995 and 2005 generation from coal plants tends to increase as these plants are used to meet increasing loads in areas with surpluses of generation capacity at present. After 2005, the use of coal plants tends to decline as the plants age and are replaced with less capital intensive new technologies, such as combined-cycle combustion turbines (see Section 4.3.1). With all alternatives, impacts that tend to result from all thermal power plants, such as thermal discharge and CO_2 emissions, show a steady increase over time, although the Program Alternatives are estimated to result in fewer impacts than the No-Action Alternative.

Electricity generation from coal plants is also related to a fourth trend. Coal combustion, and its related effects, tend to remain relatively unchanged across the Program Alternatives. Effects that result from both natural gas and coal (for example, thermal discharge, water consumption, and CO_2 emissions) tend to vary more by alternative as natural gas is used to a differing extent in response to uncertainty

TABLE S.4. Planning and Environmental Profiles for Energy Resources

Planning Information	Pulverized Coal	Fluidized Bed Coal	IGCC Coal	Simple Cycle CT	Gas-Fired Combin. Cycle CT	Diesel	Wood Waste Bio-mass	Hydro elec-tric	Nuclear Reactor	Flashed Steam Geo-thermal Plant	Muni cipal Solid Waste	Solar	Wind	Cogener-ation [a]
Expected 1995 Capacity, MW	78,674			6,911	2,078	536		21,005	9,818	1,869		380	1,600	
Capital Cost, \$/kW [b]	1,613.45	1,844.6	1,452.45	445.05	595.7				1,987.2	2,089.55		3,245	1,217	595.7
Operations and Maintenance Cost, mills/kWh [b]	7.809	8.893	7.98	8.947	4.741				10.809	13.019		22	19	4.741
Capacity Factor	75%	95%	80%	65%	65%		80%	50%	70%	80%	80%	25%	20%	80%
Heat Rate, Btu/kWh	9,393	10,150	8,969	12,072	<8,546	13,600	14,800		10,377	20,080				11,020
Thermal Discharge, million Btu	4.79	4.79	4.79	3.29	3.29				5.0	148.4		2.6		3.29
Environmental Impact Factors	**Pulverized Coal**	**Fluidized Bed Coal**	**IGCC Coal**	**Simple Cycle CT**	**Gas-Fired Combin. Cycle CT**	**Diesel**	**Wood Waste Bio-mass**	**Hydro elec-tric**	**Nuclear Reactor**	**Flashed Steam Geo-thermal Plant**	**Muni cipal Solid Waste**	**Solar**	**Wind**	**Cogener-ation [a]**
Air Pollutants, lb/MWh														
CO_2	1,970	2,150	1,810	1,390 [g]	1,300	1,620	3,400			160	3,747	1,310		1483
SO_x as SO_2	1.6 [c]	1.5 [e]	0.66 [e]	0.009	0.006	0.557	0.258							
NO_x as NO_2	3.2 [d]	1.5	0.61 [f]	1.064 [d]	0.519	5.025	4.832				5.815	0.34		1.973
VOC	0.036	0.058	0.048 [f]	0.016	0.27	2.293	2.94			0.001	0.172	0.014		0.139
CO	0.217	0.351	0.13	0.387	0.19	7.28	6.9				3.553	0.42		0.928
TSP	0.3	0.11	0.04	0.06	0.031	2.393	10.35				0.614	0.032		0.116
PM_{10}	1.260													
N_2O	0.34	0.325	0.302	0.24	0.063		0.55				0.55	0.31		
H_2S										0.066 4				
Total Trace Elements	0.054	5.146	0.00002							0.449	0.017			

TABLE S.4. Planning and Environmental Profiles for Energy Resources, continued

Environmental Impact Factors	Pulverized Coal	Fluidized Bed Coal	IGCC Coal	Simple Cycle CT	Gas-Fired Combin. Cycle CT	Diesel	Wood Waste Bio-mass	Hydro elec-tric	Nuclear Reactor	Flashed Steam Geo-thermal Plant	Muni cipal Solid Waste	Solar	Wind	Cogener-ation [a]
Trace Radioactive, Curies/ MWh									0.0055					
Airborne water from cooling tower evaporation losses, gal/MW h									1800					
Water Pollutants, lb/MWh	c	h	i		j									k
Waste Water	520	1200	270	45	510		1400							1120
TDS	2.6	5.8	2.7	0.227	2.55		7.2		0.0056					5.58
TSS	0.0078	0.017	0.00011	.00068	0.0077		0.022							0.017
TOC		0.045		0.0018	0.02									0.044
BOD		0.012		0.0004	50.0051									0.011
Total Hardness	0.33	0.73		0.029	0.32		0.91							0.71
Total Trace Pollutant	1.88	0.000004	1.91307	0.1608	1.819		5.155		0.05002	0	0			0
Consumption, acre-ft/MWh	0.0012	0.0019	0.0018	0.00005	0.00038			0.0	0.0018	0.005		0.00003	0.0	0.0005
Radioactive effluent, Curies/MWh									0.05					
Solid Waste, lb/MW h	c	c	e								l			k
Ash	30	45	87								1054			
Sulfur		1.6												
Total Metals	0.029	0.015	0.625								1017.11			
Nuclear Solid Waste									0.028					

TABLE S.4. Planning and Environmental Profiles for Energy Resources, continued

Environmental Impact Factors	Pulverized Coal	Fluidized Bed Coal	IGCC Coal	Simple Cycle CT	Gas-Fired Combin. Cycle CT	Diesel	Wood Waste Bio-mass	Hydro elec-tric	Nuclear Reactor	Flashed Steam Geo-thermal Plant	Muni cipal Solid Waste	Solar	Wind	Cogener-ation [a]
Land Use														
Construction (acres per MW capacity)	1	1.5	0.6		0.1		2.1		1.74	0.2	1.6	3	5.9	1.7
Employment														
Construction (employee years per MW capacity)	4.7	5.1	5.7		1.4		9.6	9.3	1.8	4.1	24.1	19.6	1.9	15.1 [m]
Operations (employees per MWh generation)	.000076	.000084	.00013		.000017		.00064	.000068	.00015	.000043	.00064	.00018	.00023	.00064

Blank signifies no reported quantity.
The resources which were included in the model are simple-cycle combustion turbine, combined-cycle combustion turbine, nuclear, hydroelectric, and renewables.
The coal resources were modeled as a combination of the three technologies presented in this table.
BOD = Biological Oxygen Demand
IGCC = Integrated Gassification Combined-Cycle
PM10 = particulate matter with a diameter of 10 microns or less
TDS = Total Dissolved Solids
TOC = Total Organic Chemicals
TSS = Total Suspended Solids
VOC = volatile organic compounds
[a] Costs same as natural gas-fired combined-cycle combustion turbine
[b] Coal, natural gas, nuclear, geothermal, and cogeneration sources use 1988 EPRI TAG data (EPRI 1989) inflated to 1992 dollars using1.15 as inflator.
[c] 90% sulfur removal by flue gas desulfurization
[d] Use of low NO_x burner
[e] 95% sulfur removal
[f] Fuel gas moisturization process
[g] Water injection process
[h] 70% sulfur removal
[i] 95% sulfur removal with waste water treatment
[j] Steam injection
[k] Standard low NO_x combustor, no steam exported
[l] Dry scrubber and fabric filter
[m] Average of wood-fired and municipal solid waste combustion
Source: The basis for these factors is explained in Appendix F.

TABLE S.5. Summary of Physical Environmental and Direct Employment Impacts Associated With Each Alternative in 2005.

	No Action	Program Alternatives										
		PMI Extension							PMI Limited Extension		PMI Non-Extension	
Impact Categories	1	2	3	4	5	6	7	8	9	10	11	12
Air Emissions												
SO_X (1000s of tons)	267.89	265.51	265.51	265.50	265.51	265.51	265.50	265.51	265.51	265.51	265.32	265.32
		-2.37	*-2.37*	*-2.38*	*-2.37*	*-2.37*	*-2.38*	*-2.37*	*-2.38*	*-2.38*	*-2.57*	*-2.57*
NO_X (1000s of tons)	558.44	553.40	553.41	553.39	553.40	553.41	553.39	553.40	553.37	553.37	553.18	553.18
		-5.04	*-5.03*	*-5.04*	*-5.04*	*-5.03*	*-5.04*	*-5.04*	*-5.07*	*-5.07*	*-5.26*	*-5.26*
TSP (1000s of tons)	51.29	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.83	50.83
		-0.44	*-0.44*	*-0.45*	*-0.44*	*-0.44*	*-0.45*	*-0.44*	*-0.45*	*-0.45*	*-0.47*	*-0.47*
CO_2 (millions of tons)	388.21	384.05	384.07	384.08	384.05	384.07	384.08	384.05	384.01	384.01	384.04	384.04
		-4.16	*-4.14*	*-4.13*	*-4.16*	*-4.14*	*-4.13*	*-4.16*	*-4.21*	*-4.21*	*-4.17*	*-4.17*
Water Quality												
Consumption (1000s of acre-feet)	570.35	565.64	565.67	565.71	565.64	565.67	565.71	565.64	565.63	565.63	565.52	565.52
		-4.71	*-4.68*	*-4.64*	*-4.71*	*-4.68*	*-4.64*	*-4.71*	*-4.72*	*-4.72*	*-4.83*	*-4.83*
Waste Water (millions of tons)	106.45	105.25	105.25	105.27	105.25	105.25	105.27	105.25	105.25	105.25	105.27	105.27
		-1.20	*-1.20*	*-1.18*	*-1.20*	*-1.20*	*-1.18*	*-1.20*	*-1.20*	*-1.20*	*-1.18*	*-1.18*
Thermal Discharge (trillions of Btu)	2239.11	2218.21	2218.37	2218.52	2218.21	2218.37	2218.52	2218.21	2217.99	2217.99	2218.56	2218.56
		-20.89	*-20.73*	*-20.59*	*-20.89*	*-20.73*	*-20.59*	*-20.89*	*-21.12*	*-21.12*	*-20.55*	*-20.55*
Solid Waste - Ash (millions of tons)	5.11	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.05	5.05
		-0.05	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.06*	*-0.06*
Land Use (acres)	1252.08	1207.58	1210.08	1213.4	1207.58	1208.08	1213.48	1207.58	1211.78	1211.78	1218.68	1218.68
		-44.50	*-42.00*	*-38.60*	*-44.50*	*-42.00*	*-38.60*	*-44.50*	*-40.30*	*-40.30*	*-33.40*	*-33.40*
Employment												
Construction (1000s of employee-years)	15.58	28.88	28.92	28.96	28.88	28.92	28.96	28.88	28.94	28.94	29.04	29.04
		13.30	*13.34*	*13.39*	*13.30*	*13.34*	*13.39*	*13.30*	*13.36*	*13.36*	*13.46*	*13.46*
O&M (1000s of employees)	40.68	40.39	40.40	40.40	40.39	40.40	40.40	40.39	40.39	40.39	40.38	40.38
		-0.28	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.29*	*-0.29*

(Note: Numbers in italics show how much each alternative's impacts differ from the impacts estimated for the No-Action Alternative.)

TABLE S.6. Summary of Physical Environmental and Direct Employment Impacts Associated With Each Alternative in 2015.

	No Action	Program Alternatives										
		PMI Extension							PMI Limited Extension		PMI Non-Extension	
Impact Categories	1	2	3	4	5	6	7	8	9	10	11	12
Air Emissions												
SO_X (1000s of tons)	263.14	259.49	259.64	259.89	259.49	259.64	259.89	259.49	259.91	259.91	260.41	260.41
		-3.66	*-3.50*	*-3.25*	*-3.66*	*-3.50*	*-3.25*	*-3.66*	*-3.24*	*-3.24*	*-2.73*	*-2.73*
NO_X (1000s of tons)	573.30	563.70	564.12	564.74	563.70	564.12	564.74	563.70	564.72	564.72	565.94	565.94
		-9.60	*-9.18*	*-8.55*	*-9.60*	*-9.18*	*-8.55*	*-9.60*	*-8.58*	*-8.58*	*-7.36*	*-7.36*
TSP (1000s of tons)	51.54	50.73	50.77	50.82	50.73	50.77	50.82	50.73	50.82	50.82	50.92	50.92
		-0.81	*-0.77*	*-0.72*	*-0.81*	*-0.77*	*-0.72*	*-0.81*	*-0.72*	*-0.72*	*-0.62*	*-0.62*
CO_2 (millions of tons)	449.82	440.06	440.44	441.03	440.06	440.44	441.03	440.05	440.96	440.96	442.51	442.51
		-9.75	*-9.37*	*-8.79*	*-9.75*	*-9.37*	*-8.79*	*-9.76*	*-8.86*	*-8.86*	*-7.31*	*-7.31*
Water Quality												
Consumption (1000s of acre feet)	610.42	595.26	595.58	596.10	595.26	595.58	596.10	595.25	596.09	596.09	599.77	599.77
		-15.16	*-14.85*	*-14.33*	*-15.16*	*-14.85*	*-14.33*	*-15.17*	*-14.34*	*-14.34*	*-10.65*	*-10.65*
Waste Water (millions of tons)	129.37	126.55	126.65	126.82	126.55	126.65	126.82	126.54	126.81	126.81	127.35	127.35
		-2.82	*-2.72*	*-2.55*	*-2.82*	*-2.72*	*-2.55*	*-2.83*	*-2.56*	*-2.56*	*-2.01*	*-2.01*
Thermal Discharge trillions of Btus)	2566.38	2498.61	2500.47	2503.36	2498.61	2500.47	2503.36	2498.55	2503.01	2503.01	2517.00	2517.00
		-67.77	*-65.91*	*-63.03*	*-67.77*	*-65.91*	*-63.03*	*-67.83*	*-63.38*	*-63.38*	*-49.39*	*-49.39*
Solid Waste - Ash (millions of tons)	5.12	5.05	5.05	5.06	5.05	5.05	5.06	5.05	5.06	5.06	5.07	5.07
		-0.07	*-0.07*	*-0.06*	*-0.07*	*-0.07*	*-0.06*	*-0.07*	*-0.06*	*-0.06*	*-0.05*	*-0.05*
Land Use (acres)	2166.56	1993.88	1994.48	2013.12	1993.88	1994.48	2013.12	1987.58	2011.62	2011.62	2072.62	2072.62
		-172.68	*-172.08*	*-153.44*	*-172.68*	*-172.08*	*-153.44*	*-178.98*	*-154.94*	*-154.94*	*-93.94*	*-93.94*
Employment												
Construction (1000s of employee-years)	26.56	60.28	60.29	60.52	60.28	60.29	60.52	60.20	60.50	60.50	61.31	61.31
		33.72	*33.73*	*33.96*	*33.72*	*33.73*	*33.96*	*33.64*	*33.94*	*33.94*	*34.75*	*34.75*
O&M (1000s of employees)	42.64	41.78	41.80	41.83	41.78	41.80	41.83	41.78	41.83	41.83	42.03	42.03
		-0.86	*-0.84*	*-0.81*	*-0.86*	*-0.84*	*-0.81*	*-0.86*	*-0.81*	*-0.81*	*-0.62*	*-0.62*

(Note: Numbers in italics show how much each alternative's impacts differ from the impacts estimated for the No-Action Alternative.)

resulting from Western contract allocations. When comparing the impacts from total regional generation, these differences are quite small, less than 1 percent. However, when comparing the differences between Program Alternatives, the change varies from 2 percent to 23 percent.

A final trend is found in the distinction between impacts resulting from generation and those resulting from the construction of new capacity. Impacts related to new capacity include land use and construction employment. The differences among each alternative's effects on these categories tend to be slightly magnified in comparison to the effects resulting from generation. This is due to the focus on only new development, without the influence of existing generation plants. Existing plants, which tend to dominate the effects of new plants, have a much greater influence on the effects resulting from electricity generation. The effects shown for land use illustrate this trend most clearly.

S.2 ORGANIZATIONAL IMPACTS

Early in the EIS scoping process for Western's proposed Program, feedback from various organizations made it clear that potential programmatic impacts could alter the ways in which the organizations operated. Many of these effects are not readily quantified, yet they could have significant consequences for Western customers and could alter their behavior substantially. The abundance of comments on these impacts and the magnitude of concerns raised about some of them convinced Western that these impacts should be analyzed in this draft EIS.

When comments on these impacts were reviewed, they fell into four impact types: administrative burden, equity, flexibility, and risk/uncertainty. All four types related to how the affected organizations would operate once a Program was in place.

The potential organizational impacts of Western's alternatives were analyzed using data collected from meetings with 42 of Western's customers. Although the participating customers were not chosen to be a statistically representative sample, they did represent all customer types (e.g., municipal utilities, Federal facilities, rural electric cooperatives, etc.) and geographic regions.

The customer organizational impacts were assessed based on interviews, responses to a questionnaire, and results from a "conjoint", or tradeoff, analysis. The conjoint analysis required participants to rate hypothetical Program designs in terms of their organizational impacts and the participants' overall preferences.

For all customers, the EMP component would have the largest effect on the administrative burden impact. The extension period, EMP, and percentage extension options tend to be the most influential for the other impact types. For some customers, the penalty provisions would have a large effect on impacts. A rate penalty option was initially considered for all alternatives with the exception of the No-Action Alternative; however, this has changed under the Energy Policy Act of 1992, which defined the new penalty provision requirement. The resource extension percentage component had the largest influence on participants' overall preferences.

The results of the trade-off analysis were used to estimate the relative impacts of each of the Program Alternatives. The impacts were measured with respect to the best and worst possible combinations of Program components. Table S.7 summarizes the organizational impacts of the 12 Program Alternatives averaged across all Western customers. All of Western's customers perceive the No-Action Alternative to be more favorable than the other alternatives.

Several of the Program Alternatives proposed by Western strike a balance between components, e.g., shorter extension periods are combined with larger percentage extensions. This has the effect of narrowing the range of impacts on Western's customers, even though customers may differ in their perceptions about how the Program components would impact them. With the exception of the No-Action Alternative and Alternative 9, one of the Limited Extension alternatives, Western's customers did not uniformly view alternatives as having extreme, polar impacts. Alternative 9 ranked the worst in the flexibility impact category due to the unfavorable effects of an IRP requirement for all customers and a short extension period for some projects followed by a low percentage extension.

In many cases, the resource extension percentage component had an influential role in determining the outcome of the alternatives. The No-Action has "best" ratings primarily from the favorable impacts of the 100 percent resource extension. Likewise, the PMI Non-Extension Alternatives (11 and 12) have better impacts compared with the rest of the alternatives because of an assumed 100 percent extension. Assuming a 25-year extension period and a 90 percent resource extension to take effect after the 10-year bridging period, the PMI Limited-Extension Alternatives tend to be perceived unfavorably because of the 90 percent resource extension.

S.3 RATE IMPACTS

Impacts were analyzed from three perspectives. A utilities system model was used to estimate long-term impacts resulting from utility acquisition of energy resources. Impacts that would result in the near term directly from the costs of planning activities and from a 10 percent reduction in Western's resource allocation were analyzed separately.

S.3.1 Long-Term Utility Planning

In areas where loads and resources are more or less in balance, conservation programs that would result from the Program Alternatives would tend normally to have a positive impact on rates. The savings in 2015 would generally be higher than the savings in 2005 because the cumulative impact of the programs over 20 years would lead to a substantial reduction in the need for expensive generation resources. Retail rate impacts are summarized in Table S.8. By the years 2005 and 2015, impacts are generally negligible or trending toward lower rates. Rates are seen to be lower (in the range of 5 percent to 24 percent) by the year 2015. These magnitudes are greatly tempered by being 25 years into the future.

S.3.2 Short-Term Utility Planning

The potential average short-term rate impact resulting from IRP preparation for end-users of electricity was estimated. It was assumed that all costs increased in one year and that they were passed on to end-use customers. Costs ranged from 0.21 mills/kWh to 2.1 mills/kWh. A small number of examples based on actual experiences resulted in costs either below or at the low end of this range. This estimate was assumed to be a conservative

TABLE S.7. Organizational Impacts of Draft EIS Alternatives

Impact Type	No Action	Program Alternatives										
		PMI Extension							Limited Extension		Non-Extension	
	1	2	3	4	5	6	7	8	9	10	11	12
Administrative Burden	Best	Worse	Worse	Worse	Average	Average	Average	Average	Worse	Average	Average	Average
Equity	Best	Worse	Worse	Worse	Average	Average	Average	Average	Worse	Worse	Average	Average
Flexibility	Best	Worse	Worse	Worse	Average	Average	Average	Average	Worst	Worse	Average	Better
Risk & Uncertainty	Best	Worse	Worse	Average	Worse	Worse	Worse	Average	Worse	Worse	Average	Better

LEGEND: Best, Better, Average, Worse, Worst (high-end) range that applies to each of the alternatives except the No-Action Alternative, which would have no incremental costs.

S.3.3 Reduction in Firm Power Allocation

The dollar impacts to Western's customers when faced with losing 10 percent of available firm power were calculated as gross figures for each of the regions within the marketing area of Western's five area offices. The average wholesale rate for non-Federal power represents an average of rates that a customer might face in order to make up that power lost due to the hypothetical reduction in firm Western power. The values were derived by averaging the rates offered by those utilities providing wholesale power in States that were included in an area office's marketing area. The dollar impact may be thought of as the additional expense incurred by Western's customers as a result of the reduction in available firm power. Table S.9 summarizes the results.

Those customers purchasing the greatest quantities of power from Western would experience proportionally greater rate impacts. If the power were redistributed to new customers, these utilities' rates would likely decrease.

TABLE S.8. Difference in Retail Rates between No-Action and Program Alternatives (in nominal dollars)

Area Office	Utility Type	Percentage Difference under 25 year/98% Alternative		Percentage Difference under Non-Extension Alternative	
		2005	2015	2005	2015
BAO	Non-Generating Publics	-0.2%	-7.5%	2.4%	-3.3%
	Generating Publics	-6.1%	-13.7%	-1.5%	-8.5%
	IOUs	0	0	0	0
LAO	Non-Generating Publics	1.4%	1.4%	3.7%	-0.4%
	Generating Publics	-9.5%	-14.8%	-3.9%	-6.4%
	IOUs	-0.5%	-1.3%	0	-0.8%
PAO	Non-Generating Publics	3.0%	-10.1%	3.0%	-5.1%
	Generating Publics	-2.7%	-11.2%	-2.7%	-8.3%
	IOUs	0	0	0	0
SAO	Non-Generating Publics	0.5%	1.1%	0.5%	1.3%
	Generating Publics	-3.3%	-23.9%	-3.1%	-19.3%
	IOUs	0	0	0	0
SLCAO	Non-Generating Publics	4.1%	-5.4%	4.5%	0.2%
	Generating Publics	-1.0%	-10.4%	0.1%	-5.8%
	IOUs	0	0	0	0

IOU = investor-owned utility

TABLE S.9. Dollar Expense to Western Customers of a 10% Reduction in Available Western Firm Power

Area	Cost to Customers of 10% Reduction in Firm Power	Average Wholesale Rate for Non-Federal Power (mills/kWh)	Western Composite Rate (1991) (mills/kWh)
Billings	$21,798,070	37.00	11.25
Loveland	$3,028,660	27.16	19.17
Phoenix	$18,995,890	42.33	9.03
Sacramento	$20,979,250	60.05	32.60
Salt Lake City	$7,768,400	38.08	14.50

CHAPTER 2

Alternatives

2.0 ALTERNATIVES

Western has proposed a two-part Program that considers tying the allocation of Western's electric resources to long-term customer resource planning and the efficient use of electric energy. Potential Program components have been combined to form 12 alternatives which are described in this chapter. A No-Action Alternative, based on pre-existing program features, is included in the 12 alternatives. To ensure that the Program Alternatives analyzed in this draft environmental impact statement are given fair and equitable consideration, Western will not select a preferred alternative until after public comments on this draft EIS are considered.

The two parts of the proposed Program are the PMI and the EMP. Under the PMI, Western could give existing customers extensions of a major percentage of the Federal power resource currently committed to them with certain provisions. These provisions include the percentage of the allocation, the term of the contracts, establishment of a resource pool, the manner in which the pool would be used, and penalties for noncompliance. If no extension were offered, Western would market its resources on a project-specific basis.

The EMP would require customers to establish an energy management program, which would be applicable to all customer power resources and not just the Western allocation. Customer activities evaluated for inclusion within the EMP include IRP, or activities appropriate for certain small customers with limited resources. At an earlier stage in this public process, Western also considered a performance plan option. Due to passage of the Energy Policy Act, a performance plan is no longer a viable option and is no longer under consideration.

The EMP and PMI are each made up of several components. These components have been packaged in different combinations to form the alternatives described in this chapter. The No-Action Alternative describes Western's amended C&RE program. A description of the derivation of the range of alternatives can be found later in this chapter.

This chapter first describes the different components that make up the alternatives considered. Many public comments received during the Program development process were integrated into the alternatives. Next, options that have been proposed by the public but that have not been incorporated into the Program Alternatives are addressed. This chapter then describes the alternatives themselves. Lastly, this chapter summarizes the environmental impacts of the alternatives, which are discussed in detail in Chapter 4.

2.1 COMPONENTS OF PROGRAM ALTERNATIVES

This section describes the components that make up each of the alternatives considered in this draft EIS.

2.1.1 Energy Management Program

The objectives of the EMP are to encourage Western's customers to make energy management improvements and consider DSM practices to ensure that electrical power is used in an economically efficient and environmentally sound manner. The EMP would also support and promote cost-effective development of renewable resources by Western's customers to meet future energy needs.

Two EMP components are considered, in addition to the No-Action Alternative, as part of the alternatives. These components include IRP and activities appropriate for certain small customers with limited resources. These options were thoroughly explored during extensive public involvement conducted prior to the preparation of this draft EIS.

EMP requirements would apply to all of Western's long-term firm customers.

2.1.1.1 Integrated Resource Planning

As defined in the Act, IRP is a planning process for new energy resources that evaluates the full range of possible alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to electric customers. IRP is the focus of the EMP portion of Western's proposed Program, and is now required by Section 114 of the Act. Electric utilities have been engaged in planning to meet the needs of their customers for many years. However, IRP expands the scope and nature of the planning process and the subject of the analysis. At utilities already employing IRP, the scope of planning has expanded to consider energy-efficiency and load management programs as resources, the environmental aspects of energy production, and a variety of resource selection criteria beyond electricity price (Hirst, Goldman, and Hopkins 1990). Table 2.1 compares the differences between traditional planning and IRP.

Under the proposed Program, Western would accept IRPs from individual customers or the member-based association (MBA) to which they belong. IRPs prepared for other governmental agencies would be acceptable as long as they meet Western's criteria. Western also may allow customers to join together to prepare and submit joint IRPs. Western's acceptance would be based on adherence to the planning process and inclusion of defined contents and elements. The size and complexity of individual IRPs would vary depending on customer size, type, and demographic nature. IRPs must contain goals, schedules, expected quantifiable benefits, milestones, and expenditures. The IRPs would apply to all customer resources, not just those purchased from Western. An updated submittal would be required every five years. The following seven elements are Western's requirements for a well-developed plan, as set forth in the Act:

TABLE 2.1 Differences Between Traditional Planning and Integrated Resource Planning

Traditional Planning	Integrated Resource Planning
Focus on utility-owned central-station power plants	Diversity of resources, including utility-owned plants, purchases from other organizations, conservation and load management programs, transmission and distribution improvements, and pricing
Planning internal to utility, primarily in system planning and financial planning departments	Planning spread among several departments within utility and often involves customers, public utility commission staff, and non-utility energy experts
All resources owned by utility	Some resources owned by other utilities, by small power producers, by independent power producers, and by customers
Resources selected primarily to minimize electricity prices and maintain system reliability	Diverse resource-selection criteria, including electricity prices, revenue requirements, energy-service costs, utility financial condition, risk reduction, fuel and technology diversity, environmental quality, and economic development

Source: Hirst, Goldman, and Hopkins 1990

1) Identify and accurately compare all practicable energy efficiency and energy supply resource options available to the customer.

2) Include a two-year action plan and a five-year action plan which describe specific actions the customer will take to implement its IRP.

3) Designate least-cost options to be utilized by the customer for the purpose of providing reliable electric service to its retail consumers and explain the reasons why such options were selected.

4) To the extent practicable, minimize adverse environmental effects of new resource acquisitions.

5) In preparation and development of the plan (and each revision or amendment of the plan) provide for full public participation, including participation by governing boards.

6) Include load forecasting.

7) Provide methods of validating predicted performance in order to determine whether objectives in the plan are being met.

One of the IRP elements is the consideration of environmental effects of resource choices. To the extent practicable, customers must consider and document the environmental effects of resource options in their IRPs. The documentation could be quantitative and statistically based or the effects could be described qualitatively, depending on each customer's circumstances.

Western is not proposing to mandate that mathematically derived economic (dollars) or statistical values for environmental impacts be factored into resource decisions. Such an effort may not be reasonable, or provide useful information, for many customers. Nor is Western prohibiting a customer, if that customer chooses, from quantifying environmental impacts and considering such values in its IRP. Western is encouraging a level of effort commensurate with each customer's individual situation.

Externalities

Economists often refer to environmental impacts and costs not reflected in a transaction as externalities. As an economic term, externalities represent costs or benefits that are not priced in the marketplace (Baechler and Lee 1991; Baumol and Oates 1975). The persons, firms, or communities bearing the costs of externalities absorb them without compensation. For use in utility planning, Ottinger (et al. 1990) states that environmental externality costs are costs to society resulting from the provision of electric services, in addition to costs already incorporated in the price of those services. They are those costs that occur after all government-imposed environmental standards and regulations are met and control strategies are employed. Other names sometimes used for these costs are environmental costs, environmental damages, and damage costs.

Some states, utilities, and Federal agencies are incorporating costs for externalities into their planning processes. The costs of externalities are not directly passed on to utilities or consumers. For purposes of comparison and planning, the costs are added to the capital and operating costs of generation plants and demand-side programs. Certain States and utilities are currently using four approaches to valuing environmental externalities. These approaches are described below.

- Damage costs involve applying economic valuation techniques to estimate the costs of actual damages resulting from electricity generation. Three approaches to developing damage costs include quantifying the economic costs associated with each type of damage using econometric techniques such as contingent valuation and hedonic analysis (health effects, decreased visibility); determining the costs of mitigating the effects (developing a forest reserve to mitigate CO_2 emissions); and estimating the costs of controlling emissions (installing advanced pollution control equipment) (Buchanan 1990).
- The New York Public Service Commission has developed a statistical approach to assigning

scores and weights to environmental impacts to air, land, and water (Baechler and Lee 1991; Putta 1990). Scores are assigned based on the magnitude of an impact or a qualitative measure of its severity. Weights depend on the relative cost of controlling or mitigating an attribute of the damage costs attributable to the impacts.

- Some States use a simple adder to account for the differences in externalities produced by different resources. With this approach a technology resulting in certain types of impacts, such as thermal plants that emit CO_2, has a percentage added to its estimated costs.

- Some States require regulated utilities to account for the costs of externalities, but do not prescribe a particular method.

The costs applied or suggested by different organizations are listed in Table 2.2. The costs presented are based on values for generic plants. These costs have been used in evaluating competitive bids for new generation proposals. Actual plants with specific emission estimates would likely result in different costs.

Western is not proposing to require the quantification of environmental externalities, with mandatory use of these values in customer resource decision-making, as part of the Program. Several reasons underlie this approach. First, this controversial issue is presently the subject of public debate and scientific analysis with no consensus being reached. Until this debate and analysis has been resolved, it would be premature to attempt to require Western's customers to calculate the cost of environmental externalities. Second, even with technical assistance from Western, Western's customers would find it very difficult to develop appropriate quantifications of the environmental impacts of the multitude of resources that they now use and plan to use in the future. Finally, the Act requires Western's customers to minimize adverse environmental effects of new resource acquisitions to the extent practicable and to provide reliable electric services which will, to the extent practical, minimize life-cycle system costs. This

Congressional direction establishes an IRP review standard different from a mandatory environmental externality approach.

2.1.1.2 Other Planning Processes

Section 114 of the Act specifies that for certain customers with annual energy sales or usage of 25 GWh or less the Administrator may establish and apply different regulations if it is found that these customers have limited economic, managerial, and resource capability to conduct IRP. Such customers are required to consider all reasonable opportunities to meet their future energy service requirements using DSM, new renewable resources, and other low-cost programs that minimize, to the extent practicable, adverse environmental effects.

2.1.2 Power Marketing Initiative

The PMI features some alternatives that would extend commitments of a majority of Federal resources to existing customers under long-term firm contracts. The objective of these alternatives would be to foster customers' long-term resource planning and to promote overall electric resource efficiency by using Federal resources to encourage energy efficiency. An associated objective would be to streamline future Federal power marketing activities, including potential adjustments to marketable resources and possible withdrawals for defined purposes. Other alternatives feature a relatively shorter resource extension or would have Western market its resources on a project-specific basis in the future.

Western has combined the EMP and PMI components to form the range of alternatives for this EIS. Tables 2.3 and 2.4 summarize the various EMP and PMI components. Table 2.5 describes the alternatives developed from the components.

Western specifically desires public comment on when contracts for the extension of resources should be signed. Contract execution could take place upon publication of the Record of Decision in the *Federal Register*, or upon IRP receipt or approval by Western.

TABLE 2.2. A Comparison of Externality Costs that Would Be Added to Other Resource Costs for the Competitive Acquisition of Firm Energy (1990 mills/kWh)

Resource Type	BPA	Calif.	Mass.	Nevada	New York	Ottinger[a]
Pulverized Coal	5.1	83.1	46.5	45.4	9.1	39
Atmospheric Fluidized Bed Coal	3.0	29.3	28.9	27.8	3.3	28
Coal Gasification	2.5	21.0	25.7	27	2.5	25
Simple Cycle CT	1.5	28	22.4	21.8	3.4	
Combined Cycle CT	1.4	16.5	19	15	2.3	10
New Hydroelectric	2.0					
Natural Gas Cogeneration	1.2	10.8	9.8	9.5	1.5	
Existing Hydroelectric Additions	1.0					
Geothermal	1.0					
Wind	0.5					0-1
Solar	1.0					0-4
Conservation	0					
Wood-Fired Cogeneration	3.8	61.4	16.5	16.5	6.1	0-7
Municipal Solid Waste-						
Fired Cogeneration	7.9	127	26.3	26.3	9.9	
Nuclear	2.0					29

BPA = Bonneville Power Administration

CT = combustion turbine

Source: Bonneville 1992 and Ottinger et al. 1990

[a] Costs for this column only are in 1989 mills/kWh.

TABLE 2.3. Summary of the EMP Components Considered by Western

EMP Components	
Integrated Resource Plan	IRP required for some or all customers. IRP is a process where supply-side and demand-side resource options are consistently evaluated together to determine how to serve the electricity needs of consumers at the lowest reasonable cost.
Other Planning Options	IRP required for most customers, but Western would establish different regulations for certain small customers with total energy sales or usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility. These customers shall consider all reasonable opportunities to meet future energy services requirements using demand-side techniques, new renewable resources, and other programs that provide retail customers with electricity at the lowest possible cost, and minimize, to the extent practicable, adverse environmental effects (Energy Policy Act of 1992).

TABLE 2.4 Summary of the PMI Components Considered by Western

PMI Components	
Extension Period	10, 15, 25, or 35 years, or on a project-specific basis
Percentage Extension	90%, 95%, 98%, or 100% of marketable resource; adjustment due to operational changes possible; adjustment only after an appropriate consultation process.
Resource Pool	10% (provides support of existing customer development of new C&RE technologies), 5%, or 2% for new customers/contingencies. No resource pool for some alternatives.
Resource Adjustment Provisions	Tied to extension period; none for some alternatives; limited if contract extension is 15 years; one adjustment if extension is 25 years; two if extension is 35 years, project use adjustments are based on existing contract principles. One alternative would include adjustments on 5 years' notice for limited purposes.
Penalty	All alternatives contain the penalty provisions prescribed in the Energy Policy Act. These provisions call for a 10% surcharge for nonsubmittal after 1 year from new rule adoption, or when customers fail to comply with approved plans; or after 9 months for failure to submit after the Administrator disapproves a plan; 20% surcharge after second year of noncompliance; 30% surcharge in third year of noncompliance. This time line is illustrated in Figure 2.1. The Act also allows for a 10% power reduction as an optional penalty.

All alternatives contain the penalty provisions prescribed in the Act. These provisions call for a 10 percent surcharge for IRP nonsubmittal after one year from new rule adoption, or when customers fail to comply with approved plans, or after nine months subsequent to Western's Administrator disapproving a plan when no satisfactory resubmittal occurs. A 20 percent surcharge is called for after the second year of nonsubmittal, the first year after failure to comply with a plan, or 21 months after a plan is disapproved when no satisfactory resubmittal occurs. A 30 percent surcharge is mandated in the third year of nonsubmittal and thereafter, the second year and thereafter after failure to comply with a plan, or 33 months after a plan is disapproved when no satisfactory resubmittal occurs. This time line is illustrated in Figure 2.1. The Act also allows for a 10 percent power allocation reduction as an optional penalty. In addition, Western proposes application of the penalty for nonsubmittal of an annual progress report in a timely manner.

A detailed description of the range of PMI components evaluated in this draft EIS is provided below. Assumptions used for modeling purposes are described in Chapter 3.

PMI Components	Values or Ranges
Extension Period	1) For PMI Extension Alternatives, 15, 25, or 35 years starting at expiration of existing contracts. 2) For PMI Limited Extension Alternatives, 10 years starting with IRP approval. After 10 years, new contract extensions would be determined by project-specific marketing plans. 3) For the PMI Non-Extension Alternatives, the extension would be determined by project-specific marketing plans.
Percentage Extension	90%, 95%, or 98% of marketable resource available at the end of the term of existing long-term contracts; 100% of existing commitments for certain alternatives. The amount of power to be extended to an existing customer under the PMI Extension Alternatives would be determined according to the following formula: Contract Rate of Delivery (CROD) extension = (Customer CROD today / total project CROD under contract today) x percent extension x resource available at the end of the term of the existing contracts. Where contract rates of delivery vary by season, the formula would be used on a seasonal basis. A similar pro rata approach would be used for energy extensions. Determination of the amount of resource available after the existing contract expires, if significantly different from existing resource commitments, would take place only after an appropriate public process.
Resource Pool	1) 10% of potential allocation reserved (coupled with 90% extension) for new customers, "contingencies," and support of existing customer development of new technologies for conservation or renewable resources. 2) 5% or 2% (coupled with 95% and 98% extension) for new customers and "contingencies."

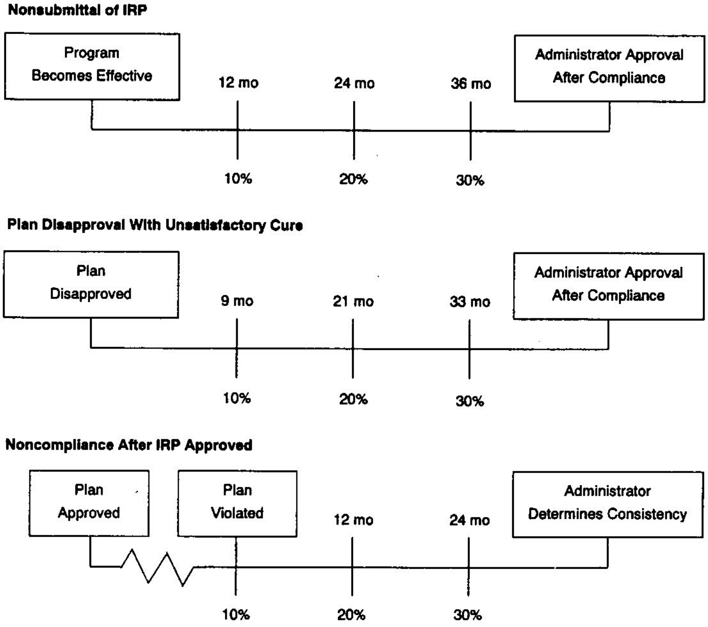
	3) One alternative couples a 98% extension with 2% for new customers only.
	4) The PMI Limited Extension Alternatives include a 100% extension for the duration of the 10-year extension.
	5) Any resource pool for the PMI Non-Extension Alternatives would be proposed on a project-specific basis.
	New customer eligibility is limited by three factors: preference, utility status by a certain date, and being located in marketing area; one-time allocation for new customers is through a separate public process.
Resource Adjustment Provisions	1) Limited adjustment provisions (in conjunction with the 15-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.
	2) One window to adjust marketable resources halfway through extension period (in conjunction with the 25-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.
	3) Two windows to adjust marketable resources at 15 years and 25 years (in conjunction with the 35-year extension option); no withdrawals for new customers; project use withdrawals can take place based on existing contract principles.
	4) One alternative (Alternative 8 in Table 2.5) allows for adjustments with 5 years' notice. The adjustment may only be used in response to changes in hydrology and river operations. Project use withdrawals can take place based on existing contract principles.
	5) Contract extensions would be determined by provisions in project-specific marketing plans in the PMI Non-Extension Alternatives.
Penalty	The penalty provision (as mandated by Congress in the Act) would be triggered by nonsubmittal of an IRP in accordance with established deadlines; not reasonably addressing the seven IRP elements or other requirements; nonsubmittal of an annual progress report in a timely manner; or no good faith customer compliance with an approved IRP. Thereafter, a monthly surcharge of 10% of the purchase price on all power obtained by a customer from Western would be assessed for each of the next 12 months of noncompliance; increasing to 20% for each of the following 12 months of noncompliance; and increasing to 30% thereafter until compliance takes place. Western reserves the right, in lieu of imposing a progressive surcharge, to impose instead a 10% resource withdrawal penalty if extraordinary circumstances exist. Penalty provisions would be incorporated into contracts that extend resources.

TABLE 2.5. Summary of Energy Planning and Management Program Alternatives

Program Components	No Action	Program Alternatives										
		PMI Extension							PMI Limited Extension		PMI Non-Extension	
	1	2	3	4	5	6	7	8	9	10	11	12
EMP	C&RE G&AC	IRP	IRP	IRP	IRP with Small Customer Provision	IRP with Small Customer Provision	IRP with Small Customer Provision	IRP	IRP	IRP with Small Customer Provision	IRP	IRP with Small Customer Provision
Extension Period	varies [a]	15 yrs [b]	25 yrs [b]	35 yrs [b]	15 yrs [b]	25 yrs [b]	35 yrs [b]	25 yrs [b]	10 yrs [c]	10 yrs [c]	varies [a]	varies [a]
Percentage Allocation	varies [a]	98%	95%	90%	98%	95%	90%	98%	100% [e]	100% [e]	varies [a]	varies [a]
Resource Pool	none [d]	2%	5%	10%	2%	5%	10%	2%	none [e]	none [e]	none [d]	none [d]
Adjustment Provisions	none [d]	limited	1 adjust.	2 adjust.	limited	1 adjust.	2 adjust.	5 yr notice	none	none	none [d]	none [d]
Penalty Provision	10% With-drawal	10% to 30% surcharge, see Figure 2.1 and Table 2.4 Optional 10% power reduction										

a To be determined by project-specific marketing plan.
b Contract extension begins at time of current contract expiration. Contracts are executed upon receipt of IRP by Western.
c Contract extensions are executed at the time of IRP approval; extension will provide resource certainty to a customer for 10 years from the date of IRP approval. After 10 years, power marketing will be determined by project-specific marketing plans.
d Unless provided by project-specific marketing plan.
e Western assumes that the percent allocation after the limited extension period will be determined by project-specific marketing plans. For purposes of analysis, this draft EIS assumes a 90% allocation after the expiration of the 10-year extension period.

FIGURE 2.1. Surcharge Penalty Provisions of the Energy Policy Act of 1992 [a]



[a] Congress has provided for a graduated rate surcharge on all power purchased from Western—not just firm power—or a 10% reduction in a power commitment, unless a customer has made a good faith effort to comply.

2.1.2.1 PMI Extension Alternatives

For those alternatives featuring relatively longer term extensions of resources, Western proposes to apply the PMI for customers whose firm electric service contract(s) expire after December 31, 1995, and before January 1, 2005, if consistent with other contractual and legal rights. Western projects that would be proposed for initial coverage under these alternatives include the Pick-Sloan Missouri Basin Program-Eastern Division and Loveland Area Projects. Resource extensions under this group of alternatives would take place upon receipt of a customer's IRP by Western.

As for Central Valley Project (CVP) resources, all power contracts between Western and its long-term firm customers expire in 2004, as does the Western-Pacific Gas & Electric Company integration contract. Because Western is at a very early stage of the post-2004 decision-making process, having just initiated an EIS for the Sacramento Area Office post-2004 marketing plan, Western will not make any decision at this time about the application of the PMI to the CVP for the post-2004 time period. (A notice of intent to prepare an EIS on the proposed Sacramento 2004 Power Marketing Program was published in the *Federal Register* on August 10, 1993 [58 FR 42536 as amended by 58 FR 43105, August 13, 1993]). Western will utilize the knowledge gained from this Energy Planning and Management Program EIS in the post-2004 marketing plan EIS. This EIS will consider the environmental impacts of applying the Program Alternatives to the CVP. As a result of further analysis in the post-2004 marketing plan EIS, Western may at a later date propose adoption of the PMI for the CVP in the post-2004 time period.

If adopted, application of this PMI to the Salt Lake City Area/Integrated Projects (SLCA/IP) resources is proposed after the ongoing electric power marketing EIS for that project is completed and the associated marketing criteria and contracts are implemented. Western's preparation of that EIS formally started with the publication of a notice of intent to prepare an EIS in the *Federal Register* on April 4, 1990 (55 FR 12550). Western's Salt Lake City EIS is separate and distinct from the U.S. Bureau of Reclamation's EIS on the operations of Glen Canyon Dam; the notice of intent to prepare the Glen Canyon Dam draft EIS was published in the *Federal Register* on October 27, 1989 (54 FR 43870).

For this group of alternatives, Western also proposes to evaluate possible further application of the PMI at least 10 years before the termination of other Western firm electric service contracts that expire after January 1, 2005—principally the Parker-Davis and Boulder Canyon Projects. Determination of further application of this initiative would be published in the *Federal Register* after an informal consultation process.

For purposes of analysis, this draft EIS evaluates impacts associated with these PMI Extension Alternatives based on the assumption that the PMI would be applied to all of Western's projects.

Under the PMI Extension Alternatives, the current marketing criteria would remain in effect until the existing contracts expire. Western proposes to retain significant provisions of existing marketing criteria for those projects that will extend resource commitments beyond the current expiration date of long-term firm power sales contracts. Western wants to retain such important marketing plan provisions as classes of service, marketing area, and points of delivery to the extent that these provisions are consistent with the proposed PMI. The PMI, allocation criteria for potential new purchasers, and retained provisions of existing marketing criteria would constitute the future marketing plan for each project under these alternatives. Any necessary amendments to existing power marketing criteria could be pursued at the time that determination is made of the resource that will be available after existing contracts expire.

The PMI components under these alternatives include different possibilities for the contract extension term, percentage extension, existence of a resource pool and contract adjustment provisions. These features could replace key portions of Western's existing power marketing contracts that are described in Section 2.1, which discusses the No-

Action Alternative. These features would not take effect until existing contracts expire.

Contract adjustment provisions for the PMI Extension Alternatives vary depending on the length of the resource extension. Limited adjustment provisions are proposed for the 15-year extension options; one window to adjust marketable resources is featured halfway through the 25-year extension period options; and two adjustment windows, at 15 and 25 years, are proposed for the 35-year extension options.

Adjustment provisions for Alternative 8 would be different than for the other alternatives. The adjustment provisions are different in response to comments raised during the public participation process. Adjustments could be made on five years' notice only in response to changes in hydrology and river operations. Adjustment would take place only after an appropriate consultation process. Adjustments to contractual commitments could take place sooner if mutually agreed to by Western and the customer. Project use withdrawals could take place based on existing contract principles.

The adjustment provisions incorporated in Alternative 8 would allow for timely response to changes in river operations and hydrology, while giving customers ample notice before any adjustment. The reasons for adjustment would be limited to only hydrology and/or operations to make Western's resource as firm as possible, while mitigating the need for possible purchase power requirements to meet firm load. Western believes this approach balances the need for reliable firm resources for customers with the recognized potential for future changes in available hydroelectric power resources.

A relationship would exist between the length of the contractual extension and the percentage of the extension in this set of proposed PMI Alternatives. The longer the term of the resource extension, the greater the risk in committing to a high level of resource availability. Western believes that a resource extension should provide the resource stability needed for effective IRP. A short extension period might be insufficient to maintain an adequate customer planning horizon and to allow for long-term project financing. For example, the short-term allocation of power to entities on the basis of energy-efficiency accomplishments would undermine resource certainty, which is the foundation of quality IRP. An extension beyond 35 years is simply too far into the future to commit resources, as Western's flexibility to respond to changing circumstances would be compromised.

Western believes that an extension of less than 90 percent of the resource to existing customers may lead to unnecessary power supply dislocations and potential development of new, but largely unneeded, supply-side resources, lessening the efficiency of the integrated system and defeating the purpose of the EMP.

2.1.2.2 PMI Limited Extension Alternatives

This set of two PMI alternatives would extend commitments of Federal resources to existing customers for a period of time sufficient to allow 1) the development of project-specific marketing plans by Western, 2) customer planning for resources in the event the project-specific hydropower resource is adjusted, and 3) the acquisition of any resources chosen during the customer planning process. Contracts for resource extensions would be signed upon approval of a customer's initial IRP by Western.

The objective of this group of alternatives would be to provide Western's customers with the minimum extension necessary to support customer preparation and implementation of IRPs. Under the Energy Policy Act of 1992, customer IRPs are due to Western one year after the final regulations become effective. Two- and five-year action plans are required in each IRP. Western believes that customers must have sufficient certainty regarding hydropower availability to plan intelligently on a least-cost basis for the future. If existing long-term firm hydropower commitments expire within the customer's planning horizon, quality least-cost planning for the future cannot take place with any confidence. The limited extension group of alternatives would respond to this situation by extending 100 percent of existing resources to existing customers for

10 years from the date of IRP approval by Western. This approach would provide for an allocation until project-specific marketing criteria can be developed and customers can adjust to the results. These alternatives are different from the others in that the extension of resources would be contingent on submittal and approval of an acceptable IRP.

The intent associated with this set of alternatives is to extend resources for a period of time adequate to effectuate a customer's IRP. For purposes of modeling and analysis, a 10-year period was tentatively chosen as an appropriate length for several reasons. If no long-term firm extensions are made pursuant to the Program, Western must develop project-specific marketing and allocation criteria for the time period after the limited extension expires. Assuming that environmental impact statements are required, Western estimates that it would take three to four years to complete each marketing plan, depending on the level of controversy. If less than 100 percent of the resource were allocated to existing customers, other resources would have to be identified by the customer to replace the unextended resource. This planning process could take as long as one year to complete. Resources identified in an IRP could be supply-side (either construction or purchase), demand-side, or renewable in nature. Implementation of demand-side measures could take as long as three years, while construction of supply-side resources could take from three to 10 years, depending on the character of the resource. Ten years appears to be a time period within which all of these activities could be accomplished, and is consistent with the shortest long-term planning horizon used in the electric utility industry.

Notwithstanding the tentative use of a 10-year term for these two alternatives, Western invites the public to comment on the length of resource extension necessary to effectuate integrated resource plans.

These PMI alternatives would apply only to projects where existing long-term firm contracts expire within 10 years of the date of initial IRP approval by Western. Customers with contracts for long-term firm power from the Pick-Sloan Missouri Basin Program-Eastern Division would likely receive resource extensions for five to six years under the PMI Extension Alternatives, depending on the date of IRP approval. Customers with contracts for power from the Loveland Area Projects would probably only receive extensions for one or two years, while entities purchasing power from the Central Valley Project or the Salt Lake City Area Integrated Projects could also receive modest extensions. This alternative would not be applicable to resources under contract far into the future, such as the Parker-Davis and Boulder Canyon Projects; a limited extension in support of IRP effectuation is unnecessary when existing contracts extend far into the future.

2.1.2.3 PMI Non-Extension Alternatives

Under this set of alternatives, Western would implement the provisions of the Energy Policy Act of 1992 without extending resources under this Program. These alternatives combine the requirements of the Energy Policy Act of 1992 (including the new penalty provision) with the PMI provision of the No-Action Alternative. All power would be marketed on a project-specific basis, with independent public processes and environmental documentation.

2.1.3 Conservation and Renewable Energy Program - An Element of the No-Action Alternative

In 1981, Western developed and began implementing a power marketing contract article requiring purchasers of long-term firm power (Western's customers) to develop a C&RE program. The C&RE program forms the No-Action Alternative. G&AC specify the requirements for customer C&RE plans. The G&AC were published in the *Federal Register* (46 FR 56140) on November 13, 1981. Legislation reinforcing Western's ongoing program was included in Title II of the Hoover Power Plant Act (42 USC 7275-7276). After the Hoover Power Plant Act was passed, an amendment to the G&AC was published in the *Federal Register* (50 FR 33892 1985). G&AC requirements are incorporated into a C&RE contract article, which is part of a customer's existing power marketing contract. The contract articles contain a noncompliance penalty provision of a 10 percent reduction in Western power contract commitments.

Western notified the public in January 1993 that it would no longer require customer compliance with the G&AC in order to facilitate the preparation of IRPs by Western's long-term firm power customers (58 FR 3552). To have a basis for comparative analysis, the No-Action Alternative assumes the G&AC would have continued in the absence of Program adoption and passage of the Energy Policy Act of 1992.

Under the G&AC, customers were responsible for developing and implementing programs for efficient energy production and conservation goals. A customer's program submission described specific program content. Western's G&AC included a list of suggested actions for customer consideration. This list is reproduced in Appendix B. The list is broad and includes activities in the areas of energy consumption efficiency improvements, use of renewable energy resources, load management techniques, cogeneration, rate design improvements, production efficiency improvements, and activities conducted for other agencies. Western gave full or partial credit for programs required by other entities that met the requirements of the C&RE program.

Acceptance criteria for customer programs were based on the customer's classification (i.e., cooperative, public utility district, etc.) and the level of effort proposed. Customer programs were required to contain a minimum number of annual on-going or planned activities. The number of activities varied by utility type and the quantity of system sales or consumption. The smallest customers were required to do one C&RE activity; the largest customers five. Table 2.6 shows the required number of activities for each customer type.

The descriptions of these activities, including goals and schedules, were the most important elements of a C&RE plan. The customer's program submittal included the following items as part of this description:

- designated contact person within the customer's organization
- statements adopted by the customer's governing body regarding formal C&RE policies and objectives
- a description of each ongoing or proposed Program activity; customers are to use the G&AC list for activity selection (this list is contained in Appendix B). Where energy savings or added energy/capacity supply goals may be quantified for each activity, such data should accompany each program submittal
- identification of customer goals, plans, schedules, and locations for each activity
- methods for determining successful program accomplishment
- documents prepared for other Federal, State, or local agencies that could be submitted in lieu of or supplemental to Western's requested information
- specific areas where a customer feels that assistance is needed from Western
- identification of potential adverse environmental impacts and issues of proposed C&RE activities
- any additional data or information that a customer wants to include as part of a program description.

Western reviewed customer programs every two years. Every four years verification of at least 70 percent attainment of goals was required. Western's C&RE review process consisted of the following elements:

- reviewing customer submissions against defined criteria
- answering customer questions and providing necessary assistance

- imposing penalties if a customer is found in violation of its contractual C&RE obligation.

Western committed to review and may modify the G&AC criteria at intervals of not less than three years or more than five years (50 FR 33892 - 33899, August 21, 1985). It was as a result of one of these reviews that Western initially proposed the program modification assessed in this draft EIS.

Western recognizes that the past efforts of many of its customers in implementing conservation and DSM have been significant and have far exceeded the minimum requirements under the C&RE program. Historic investments by Western's customers will influence the future resources available for consideration in an IRP.

Although enforcement provisions for noncompliance with the G&AC are included in all long-term, firm contracts, the existing C&RE program is not directly linked to power marketing provisions such as contract extensions and percentage allocations.

2.1.4 Technical Assistance - An Element Common to All Alternatives

Western's technical assistance program has been successful in helping utilities meet program requirements and accomplish their goals in conservation and renewable energy. Western fully intends to continue providing its customers with an appropriate level and mix of technical assistance.

Technical assistance is a program element that spans across all alternatives. Western is committed to the pursuit of technical assistance activities, and recognizes that the level of effort and the types of activities would be similar under the various alternatives. The content of specific workshops or seminars that Western may offer might vary under the alternatives because of differing program requirements and customer needs. However, these variations are likely to be minimal and would not affect the level of overall effort.

Since 1981, Western has provided its customers

TABLE 2.6. Required C&RE Ongoing Activities for Customer Programs

Customer Type	Total customer system sales or annual consumption if a nonutility (in GWh/yr)		
	<50	50 - 100	>100
Cooperatives	3	4	5
Municipalities	3	4	5
Public utility districts	3	4	5
Federal or State agencies	3	4	5
Investor-owned utilities	3	4	5
Parent entity and members	3	4	5
Public power district	3	4	5
Irrigation district with utility function	3	4	5
Irrigation district without utility function	1	1	1
Source: 50 FR 33897			

with a wide range of technical assistance in support of the conservation and renewable energy program. The approximate budget for this support in fiscal year 1994 is $4.4 million. Additional funding from sources providing complementary service and partnerships with customers continues to be sought to leverage the benefits of the service, reduce financial risk, and remove barriers to the successful application of emerging technologies.

Western evaluates its involvement and support for technical assistance and technology transfer activities against the following criteria which are consistent with those for a successful energy management program: the activity must maintain or enhance the existing level of energy service; the activity must produce benefits that equal or exceed the cost to the customer and/or consumer; the benefits must be measurable; and the activity must be environmentally sensitive.

IRP is the focus of Western's support activities. An example of this IRP focus is Western's development of a series of workbooks known as the Resource Planning Guide (RPG). The RPG, which has been under development for a number of years, provides Western's customers with a guide to the development of an IRP process. The RPG has been well received as a valuable planning tool for the future. The RPG, which was developed with the participation of 42 utilities, is now available in a computer disc format for customer usage in compliance with the final Program regulations. Activities such as workshops, peer matches, seminars, equipment loans, technology transfer, publications, and cooperative cost-shared efforts with customers and other supporting organizations would continue, especially as they relate to IRP. In addition to those ongoing assistance efforts, Western is willing, in cooperation with its customers, to develop joint venture DSM and renewable energy pilot/ demonstration projects. Some possible additional activities include assistance in developing new funding and incentive programs to promote DSM, and locally based technical services to specific customer groups. One specific example of this is a photovoltaics "circuit-rider," a technician who provides support services to a group of customers who participate in the funding.

Western's technical assistance support is available to customers upon request. The technical assistance Western offers is best described as a set of tools which customers use in support of meeting their contractual obligations. Not all customers need or want such assistance. On the other hand, technical assistance will help many customers to meet or exceed program requirements.

Western's technical assistance has been tailored each year to meet the current needs of the program and the customers. Given the numerous changes and challenges experienced and anticipated in the utility industry, and rapidly changing technologies, it is not possible to project exactly what the content of technical assistance efforts may be over the projected term of proposed contract extensions. Technical support must remain flexible and capable of rapid change. Western has provided for such change in the last decade and will continue this practice in the future.

External factors may have the most influence on the types of assistance that will be needed. For example, Western may need to train its customers in the future in the application of new technologies that have not yet been developed, or new approaches that are yet to be designed. As specific technical assistance activities are proposed in the future, they will be evaluated for appropriate documentation under NEPA.

2.2 ISSUES NOT INCORPORATED INTO PROGRAM ALTERNATIVES

The range of alternatives incorporated into this draft EIS was determined after an extensive public involvement process which included 38 public meetings and workshops, and distribution of seven newsletters and one brochure to explain the issues and allow for public involvement. Ranges of alternatives were set forth in a public newsletter distributed in September of 1991; these initial ranges were explained and discussed in a public meeting held on

September 30, 1991, in Denver, Colorado. In addition, eight alternatives workshops were held in March and April of 1992 to help further define alternatives.

A number of issues raised during the Program development process have been found to be not responsive to the need for the Program or its purpose, and were determined to be outside the scope of Western's analysis. Therefore, these issues were not incorporated into alternatives evaluated in this draft EIS. The following subsections provide clarification and information about these issues.

2.2.1 Transmission Access

Western encourages and practices open transmission access. However, Western believes that giving credit to a customer providing access to its transmission system is not within Western's specific need of encouraging customers to pursue improvements in their energy management efforts. The important and controversial issue of transmission access will be addressed and resolved through other processes. Even though the issue of transmission access will not be addressed through the decision-making process addressed by this EIS draft, Western believes that access to reasonably priced transmission is an important consideration in a customer's resource comparisons and evaluations in an IRP. This is especially the case when a particular customer needs transmission access to acquire a cost-effective resource.

2.2.2 Incentive Rates/Rate Design Modifications by Western

Incentive rates and rate design modifications are not analyzed as part of this draft EIS. While alternatives to Western's rates and rate designs might encourage conservation, they would not encourage comprehensive long-term energy management planning by Western's customers. Western believes that incentive rates and rate designs to encourage conservation should be appropriately analyzed in subsequent environmental documentation associated with proposed changes to the existing rate and rate design methodologies, within the long-established, public rate-making process. Procedures to ensure appropriate public participation in the rate development process are set forth in 10 CFR 903.

2.2.3 River and Dam Operations

The PMI portion of the Program includes components for the amount of resource extended to current customers, the length of the extensions, and the amount of resource designated for a resource pool that may be used for several purposes. The Program does not propose to alter the total amounts of power or energy marketed by Western, or to make changes in the conditions for marketing of power and energy, or to make changes in the operations of any generation facilities. In fact, the Program is intentionally designed to respond to changes in marketable resources due to hydrology or operational changes, which very likely would be initiated by agencies other than Western.

Any proposed future changes to marketing conditions, or to river or dam operations, or any other action that may cause such changes would be a separate Federal proposed action with its own purposes and needs. Such actions may refer to this EIS and would have separate NEPA environmental documentation to analyze the impacts from defined actions to specific river systems.

The Program will neither cause changes to river or dam operations nor will it impede such changes. All alternatives are neutral with respect to river and dam operations, even though some may offer Western more flexibility in responding to operational changes stemming from other actions or projects.

2.2.4 Ecological and Recreational Resources

In a manner similar to the preceding river and dam operations issue, the proposed Program does not change the conditions under which Western markets power and energy, or the operation of rivers or dams. Any future changes to power marketing conditions or changes to river or dam operations that may have impacts on ecological or recreational resources are separate proposed actions with their own purposes and needs. Such actions, which may be proposed by other Federal agencies, will have their own NEPA environmental documentation.

The Program will neither result in changes to ecological or recreational resources caused by changes in river and dam operations, nor will it impede such changes. All alternatives are neutral with respect to these ecological and recreational resources, even though some may offer Western more flexibility in responding to future changes. Customer responses to Western's proposed Program may result in ecological impacts, which are described in Chapter 4 and summarized in Section 2.5.

2.2.5 Regional IRPs

During the scoping process, comment was received that Western should develop regional integrated resource plans (IRPs) for each of the geographic regions it serves, either by river basins or some other demographic boundaries. Such IRPs would, almost by definition, be extensive in scope and require the expenditure of substantial resources. Some opinions favor the inclusion of such IRPs in this Program.

Western has no load growth responsibilities — the power customers do. Western markets a fixed supply of hydroelectric power that is subject to seasonal weather fluctuations in various geographical regions. The vast majority of Western's customers are not solely dependent upon Western for their supply of power. Western does not have legislative or regulatory authority over the supply or demand of the customers its serves. Under these circumstances, it is neither appropriate nor feasible for Western to attempt to develop regional IRPs for its 15-state service territory.

Western believes that resource, geographic, and other differences among areas of its service territory will be evident as a result of any IRP process conducted by its customers, and therefore, it is unnecessary to attempt to modify the "process" itself to the needs of different regions. Regional sensitivities are reflected in this EIS and will be highlighted in customer IRPs.

2.2.6 Conservation Purchases by Western

The option for Western to purchase energy conservation in lieu of furnishing a supply of power from its hydroelectric resources was suggested during the scoping process. Conservation purchases by Western are not a component of the alternatives in this draft EIS, because they do not contribute to marketing Federal power on a long-term basis in accordance with Western's mission as a power marketing administration and Western is not responsible for meeting its customer loads beyond contracted rates of deliveries. Further, conservation purchases are not appropriate on a Westernwide basis when many of the States within Western's marketing area have power surpluses. Western encourages its customers to pursue such purchases when opportune. The cost-effectiveness of conservation purchases would be appropriate for evaluation in a customer's IRP.

2.2.7 Project Use Efficiency

Western received comments that it should invest in energy use efficiencies for project use loads. Project use power is that power reserved to meet project needs as authorized by Congress, such as main lift pumping for irrigation, station service, and salinity control. Western markets power available in excess of that needed to serve project purposes.

Western received comments that it should allocate the project use energy saved to preference customers or reduce firming purchase power requirements. Western also received a comment that customers could be given the opportunity to make efficiency improvements in exchange for the energy saved.

Investment opportunities have been discussed with the U.S. Bureau of Reclamation and the U.S. Army Corps of Engineers which are responsible for project use facilities. An evaluation report, done by Western and the Bureau of Reclamation on project use efficiency opportunities for the CVP, indicated very limited cost-effective opportunities for development (U.S. Bureau of Reclamation et al. 1992). However, the four potential generation efficiency improvements that were cost-effective could increase project energy available for marketing by 123 GWh per year at a cost of 0.7 to 36.9 mills/kWh.

Because investment in project use efficiency improvement opportunities does not encourage long-term energy management planning by Western's customers, Western will not include this issue within the Program EIS analysis. These opportunities have been and will be pursued independently.

2.3 INCENTIVES

Western received public comments that incentives should receive more emphasis in the Program. Allocations of power from a resource pool to customers with exemplary achievement in energy efficiency were suggested as incentives. Western believes that the adoption of such competitive incentives for program compliance is impractical for the following reasons.

Western serves a wide variety of customers. Western has recognized from the outset that there would be varying levels in the sophistication and complexity of IRPs, reflecting each customer's size, type, resource needs, and geographic area. Resource choices and the timing of implementation would vary depending upon the circumstances involved. Given this diversity of customer characteristics and resource strategies, Western has not found an equitable way to judge and appropriately reward the energy efficiency achievements of its customers. For example, it would be a difficult task to decide whether the conservation efforts of a small irrigation district are comparable to the achievements of a much larger, vertically integrated utility. Since larger utilities have more opportunities to excel in this area, competition for power could serve to redistribute power from smaller customers to larger utilities with the staff, resources, and knowledge to succeed. Because customers facing load growth have greater opportunity to plan and implement cost-effective DSM and energy efficiency resources, the concept of competition could similarly work to the detriment of customers facing stable loads or experiencing supply-side resource surpluses.

Western has another concern about providing incentive allocations out of a resource pool. When an incentive allocation is made up of long-term firm power taken from existing customers, Western undermines resource stability to existing customers. Due to customer uncertainty of receipt of power from such a pool, otherwise unnecessary power purchases or long-term commitments for purchases could take place, causing increased expense to the consumer. In regions where surpluses are not available for purchase on a long-term basis, construction of supply-side generation or transmission lines could be induced if Western creates a relatively large resource pool from power currently allocated to existing customers. Balance must be achieved between avoiding disruption in existing power supply and transmission arrangements and the development of appropriate incentives for IRP preparation. For these reasons, the alternatives do not feature the allocation of long-term firm power out of a resource pool as an incentive for existing customers.

Some extension alternatives evaluated in this draft EIS propose that resource extension contracts be signed upon receipt of a customer's IRP by Western. Other alternatives would have extension contracts executed upon approval of a customer's IRP by Western. Both of these approaches feature incentives for the expeditious preparation and submittal of quality IRPs.

The planning stability that results when a customer can depend on its Federal power commitment can be seen as an incentive. Planning for the future cannot take place with any confidence if this stability is compromised. Energy-efficient resource choices, with their associated economic and environmental benefits, are more difficult to realize if the existing resource base is uncertain. The financing of new renewable and DSM resources could be adversely impacted if existing resources are not sufficiently firm for planning purposes.

Customer energy efficiency is driven by the cost of supplemental electricity supply. The price differential between Western's power and the cost of power from other sources is often significant.

Western believes that the economic price signals resulting from this price disparity offer a more significant incentive than any Western could propose. Western provides a varying amount of a customer's energy needs but virtually all customers require a supplemental supply to meet their total energy needs.

Western also views its technical assistance program as offering a significant incentive for customers to pursue energy efficiency. A major goal of Western's technical assistance program is to inform its customers of the economic benefits of energy efficiency, so that opportunities identified in IRPs are pursued with an understanding of those benefits. Assistance is available from Western to aid customers in their development of consumer incentives for energy efficiency. Better energy efficiency achievement results when effort is focused on utility incentives to consumers, as opposed to incentives from Western to a purchasing utility. This is especially the case when the purchasing utility is a MBA one or two levels removed from the end-use consumer.

Technical assistance would also support the marketing efforts of Western customers as they pursue cost-effective demand-side management activities. The environmental and cost-saving benefits resulting from IRP preparation, developed with full public participation, are sufficient incentives for IRP implementation without further incentive from Western.

Western originally viewed the extension of resource commitments to existing customers as a significant inducement for the preparation of IRPs. With the passage of the Act, Western's long-term firm power customers now must prepare IRPs whether resources are extended or not. However, the availability of power for allocation to new customers remains a powerful incentive for the preparation of IRPs by those not presently receiving the benefits of Federal hydroelectric power.

Western continues to investigate the possibility that further regional energy efficiency incentives might be identified. Western may, if appropriate, develop targeted incentives on a project-by-project basis, if such an approach has regional merit. One opportunity for consideration of such an incentive approach would be at the time that Western determines the resource available at the end of the term of existing contracts. Further NEPA environmental documentation would be prepared, as needed, when Western considers specific future actions.

2.4 DESCRIPTION OF ALTERNATIVES

The EMP and PMI components, along with the features of the amended G&AC, make up the components for the 12 alternatives analyzed in this draft EIS. The alternatives are summarized in Table 2.5. In its June 1992 UPDATE newsletter, Western identified a tentative preferred alternative as the alternative it was most likely to endorse, subject to the results of the ongoing analysis. To ensure that the Program Alternatives featured in this draft environmental impact statement are given fair and equitable consideration, Western will not select a preferred alternative until after public comments on this draft EIS are considered.

2.4.1 The No-Action Alternative

The No-Action Alternative consists of the amended C&RE program and the project-specific independent marketing plans established by the area offices. Currently, Western markets its resources through independent marketing plans that are developed for specific hydroelectric projects, each with its own set of customer power contracts.

Under the No-Action Alternative, the existing time frames for Western's resource marketing would remain the same. Four of the existing plans will expire by 2005. In the Billings Area Office contracts for 2,029 MW (including peaking power) will expire in 2000. The Sacramento, Loveland, and Salt Lake City area offices administer contracts for a total of 3,341 MW set to expire in 2004. The Phoenix Area Office markets 217 MW from the Parker-Davis Project under contracts that will expire in 2008. Western anticipates extended contracts under this alternative would incorporate variable contract terms. The contracts would not include provisions for adjustments or resource pools.

2.4.2 The PMI Extension Alternatives - 2 through 8

Alternatives 2 through 8 provide different approaches to linking power marketing with energy management. Western has developed four packages of options for the PMI portion of the Program and two options for the EMP portion. In combination, these packages make up seven alternatives under discussion. The EMP package contains the following combination of components.

Each of the alternatives includes IRP; some offer small customers the choice of other ways of meeting the EMP requirements.

- **EMP Option A** — IRP required for all customers.
- **EMP Option B** — IRP required for most customers, but Western would establish different regulations for certain small customers with total energy sales or usage of 25 GWh or less which are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility. These customers shall consider all reasonable opportunities to meet future energy services requirements using DSM techniques, new renewable resources and other programs that will provide retail customers with electricity at the lowest possible cost, and minimize, to the extent practicable, adverse environmental effects.

All PMI extension options include an identical penalty provision as required by Section 114 of the Energy Policy Act of 1992. This penalty provision would be incorporated into the contracts that extend resources.

The resource pool provisions under Alternatives 2 through 8 allow for allocations to new customers and for contingencies. The PMI extension options are summarized below:

- **PMI Option A** — 15-year contract term with a 98 percent extension of resources, a 2 percent resource pool, and limited adjustment provisions.
- **PMI Option B** — 25-year contract term with a 95 percent extension of resources, a 5 percent resource pool, and one window to adjust resources halfway through the term.
- **PMI Option C** — 35-year contract term with a 90 percent extension of resources, a 10 percent resource pool, and two windows to adjust resources at 15 years and 25 years. The resource pool under this option includes a provision to support existing customer development of new technologies for conservation or renewable resources.
- **PMI Option D** — 25-year contract term with a 98 percent extension of resources, a 2 percent resource pool and limited adjustment provisions on five years' notice.

2.4.3 The PMI Limited Extension Alternatives - 9 and 10

This pair of Limited Extension Alternatives would extend commitments of Federal resources to existing customers for a period of time sufficient to allow 1) the development of project-specific marketing plans by Western, 2) customer planning for resources in the event the project-specific hydropower resource is adjusted, and 3) the construction of any resources chosen during the customer planning process. The time period for extension would start from the date of Western's approval of a customer's IRP; the extension amount would be 100 percent of existing resources. Provisions of the Energy Policy Act of 1992 would be implemented.

2.4.4 The PMI Non-Extension Alternatives - 11 and 12

Under this pair of Non-Extension Alternatives, Western would implement the provisions of the Energy Policy Act of 1992 without extending resources under this Program. Alternative 11 would require preparation of IRPs, while Alternative 12 would allow for small customer provisions. These alternatives couple together the requirements of the Energy Policy Act of 1992 (including the new penalty provision) with the PMI provision of the No-Action Alternative.

2.5 SUMMARY OF ENVIRONMENTAL IMPACTS

Table 2.5 summarizes the salient provisions of the 12 alternatives. All Program Alternatives would have beneficial environmental and social impacts in comparison to the No-Action Alternative. The impacts of the Program Alternatives vary depending on the environmental resources being affected. There are two key issues that contribute to the variation. The first is the operation of generating technologies that would result under each alternative. Effects that are primarily related to coal combustion (for example, SO_x and TSP emissions or ash production) would tend to remain unchanged across the Program Alternatives. Effects that result from both natural gas and coal (for example, thermal discharge, water consumption, and CO_2 emissions) would tend to vary more by alternative as natural gas is used to a differing extent in response to uncertainty resulting from Western contract allocations. When comparing the impacts from total regional generation, these differences are quite small, less than 1 percent. However, when comparing the incremental changes between the alternatives, the difference varies from 2 percent to 23 percent.

The second issue is the distinction between impacts resulting from generation and those resulting from the construction of new capacity. Impacts related to new capacity would include land use and construction employment. The differences among each alternative's effects on these categories tend to be magnified in comparison to the effects resulting from generation due to the focus on only new development, without the influence of existing generation plants. Existing plants, which tend to dominate the effects of new plants, have a much greater influence on the effects resulting from electricity generation. Potential impacts are summarized in Tables 2.7 and 2.8.

Two analytic techniques were used to assess employment impacts and effects on trade and commerce. Taken together, these analyses show impacts ranging from neutral to positive resulting from the Program Alternatives in comparison with the No-Action Alternative. The Program Alternatives would tend to increase estimated direct employment from the construction of generation plants and the installation of conservation measures. These jobs would result from the labor-intensive nature of conservation. The Program Alternatives are projected to increase direct employment from approximately 13,300 to 13,460 employee years in 2005 and from approximately 33,640 to 34,750 employee years in 2015 (see Tables 2.7 and 2.8). Taken together over the 20-year study period, the increment between the alternatives amounts to an average of about 2,400 employee-years per year. On a regional basis the Program Alternatives would affect the regional economy neutrally. The economic impacts on trade and commerce were found to be nearly zero with some slightly negative effects through 2005 and 2015 across all five of the Western areas (see Section 4.9, "Social and Economic Effects").

Rate impacts were analyzed from a number of perspectives. The Program Alternatives could result in short-term rate increases to cover the cost of IRP. However, the Program Alternatives should result in a rate decrease over time as utilities make more efficient use of resources (see Section 4.10, "Rate Impacts").

The Program itself would have no direct impacts on the environment. Western estimates the Program's aggregate indirect impacts that would be produced by the anticipated customer response, but specific customer activities in response to the Program cannot be determined. These specific activities could have impacts in the future, and would be addressed once specific actions are identified. In comparison with the No-Action Alternative, the analysis found that the Program Alternatives would consistently result in fewer negative physical environmental effects.

TABLE 2.7. Summary of Physical Environmental and Direct Employment Impacts Associated With Each Alternative In 2005

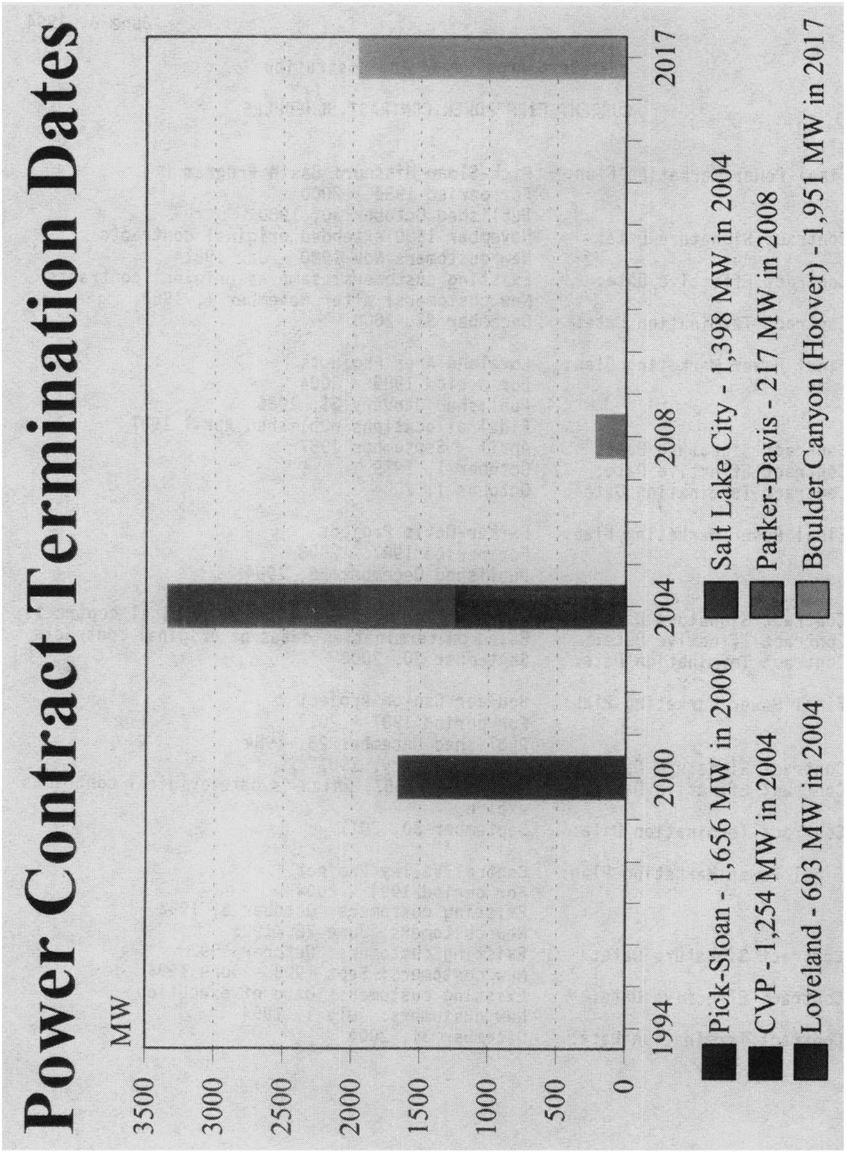
Impact Categories	No Action	Program Alternatives										
		PMI Extension							PMI Limited Extension		PMI Non-Extension	
	1	2	3	4	5	6	7	8	9	10	11	12
Air Emissions												
SO_X (1000s of tons)	267.89	265.51	265.51	265.50	265.51	265.51	265.50	265.51	265.51	265.51	265.32	265.32
		-2.37	*-2.37*	*-2.38*	*-2.37*	*-2.37*	*-2.38*	*-2.37*	*-2.38*	*-2.38*	*-2.57*	*-2.57*
NO_X (1000s of tons)	558.44	553.40	553.41	553.39	553.40	553.41	553.39	553.40	553.37	553.37	553.18	553.18
		-5.04	*-5.03*	*-5.04*	*-5.04*	*-5.03*	*-5.04*	*-5.04*	*-5.07*	*-5.07*	*-5.26*	*-5.26*
TSP (1000s of tons)	51.29	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.83	50.83
		-0.44	*-0.44*	*-0.45*	*-0.44*	*-0.44*	*-0.45*	*-0.44*	*-0.45*	*-0.45*	*-0.47*	*-0.47*
CO_2 (millions of tons)	388.21	384.05	384.07	384.08	384.05	384.07	384.08	384.05	384.01	384.01	384.04	384.04
		-4.16	*-4.14*	*-4.13*	*-4.16*	*-4.14*	*-4.13*	*-4.16*	*-4.21*	*-4.21*	*-4.17*	*-4.17*
Water Quality												
Consumption (1000s of acre-feet)	570.35	565.64	565.67	565.71	565.64	565.67	565.71	565.64	565.63	565.63	565.52	565.52
		-4.71	*-4.68*	*-4.64*	*-4.71*	*-4.68*	*-4.64*	*-4.71*	*-4.72*	*-4.72*	*-4.83*	*-4.83*
Waste Water (millions of tons)	106.45	105.25	105.25	105.27	105.25	105.25	105.27	105.25	105.25	105.25	105.27	105.27
		-1.20	*-1.20*	*-1.18*	*-1.20*	*-1.20*	*-1.18*	*-1.20*	*-1.20*	*-1.20*	*-1.18*	*-1.18*
Thermal Discharge (trillions of Btus)	2239.11	2218.21	2218.37	2218.52	2218.21	2218.37	2218.52	2218.21	2217.99	2217.99	2218.56	2218.56
		-20.89	*-20.73*	*-20.59*	*-20.89*	*-20.73*	*-20.59*	*-20.89*	*-21.12*	*-21.12*	*-20.55*	*-20.55*
Solid Waste - Ash (millions of tons)	5.11	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.05	5.05
		-0.05	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.05*	*-0.06*	*-0.06*
Land Use (acres)	1252.08	1207.58	1210.08	1213.48	1207.58	1208.08	1213.48	1207.58	1211.78	1211.78	1218.68	1218.68
		-44.50	*-42.00*	*-38.60*	*-40.50*	*-42.00*	*-38.60*	*-44.50*	*-40.30*	*-40.30*	*-33.40*	*-33.40*
Employment												
Construction (1000s of employee-years)	15.58	28.88	28.92	28.96	28.88	28.92	28.96	28.88	28.94	28.94	29.04	29.04
		13.30	*13.34*	*13.39*	*13.30*	*13.34*	*13.39*	*13.30*	*13.36*	*13.36*	*13.46*	*13.46*
O&M (1000s of employees)	40.68	40.39	40.40	40.40	40.39	40.40	40.40	40.39	40.39	40.39	40.38	40.38
		-0.28	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.28*	*-0.29*	*-0.29*

(Note: Numbers in italics show how much each alternatives' impacts differ from the impacts estimated for the No-Action Alternative)

TABLE 2.8. Summary of Physical Environmental and Direct Employment Impacts Associated With Each Alternative in 2015

Impact Categories	No Action	Program Alternatives										
		PMI Extension							PMI Limited Extension		PMI Non-Extension	
	1	2	3	4	5	6	7	8	9	10	11	12
Air Emissions												
SO_X (1000s of tons)	263.14	259.49	259.64	259.89	259.49	259.64	259.89	259.49	259.91	259.91	260.41	260.41
		-3.66	*-3.50*	*-3.25*	*-3.66*	*-3.50*	*-3.25*	*-3.66*	*-3.24*	*-3.24*	*-2.73*	*-2.73*
NO_X (1000s of tons)	573.30	563.70	564.12	564.74	563.70	564.12	564.74	563.70	564.72	564.72	565.94	565.94
		-9.60	*-9.18*	*-8.55*	*-9.60*	*-9.18*	*-8.55*	*-9.60*	*-8.58*	*-8.58*	*-7.36*	*-7.36*
TSP (1000s of tons)	51.54	50.73	50.77	50.82	50.73	50.77	50.82	50.73	50.82	50.82	50.92	50.92
		-0.81	*-0.77*	*-0.72*	*-0.81*	*-0.77*	*-0.72*	*-0.81*	*-0.72*	*-0.72*	*-0.62*	*-0.62*
CO_2 (millions of tons)	449.82	440.06	440.44	441.03	440.06	440.44	441.03	440.05	440.96	440.96	442.51	442.51
		-9.75	*-9.37*	*-8.79*	*-9.75*	*-9.37*	*-8.79*	*-9.76*	*-8.86*	*-8.86*	*-7.31*	*-7.31*
Water Quality												
Consumption (1000s of acre feet)	610.42	595.26	595.58	596.10	595.26	595.58	596.10	595.25	596.09	596.09	599.77	599.77
		-15.16	*-14.85*	*-14.33*	*-15.16*	*-14.85*	*-14.33*	*-15.17*	*-14.34*	*-14.34*	*-10.65*	*-10.65*
Waste Water (millions of tons)	129.37	126.55	126.65	126.82	126.55	126.65	126.82	126.54	126.81	126.81	127.35	127.35
		-2.82	*-2.72*	*-2.55*	*-2.82*	*-2.72*	*-2.55*	*-2.83*	*-2.56*	*-2.56*	*-2.01*	*-2.01*
Thermal Discharge (trillions of Btus)	2566.38	2498.61	2500.47	2503.36	2498.61	2500.47	2503.36	2498.55	2503.01	2503.01	2517.00	2517.00
		-67.77	*-65.91*	*-63.03*	*-67.77*	*-65.91*	*-63.03*	*-67.83*	*-63.38*	*-63.38*	*-49.39*	*-49.39*
Solid Waste - Ash (millions of tons)	5.12	5.05	5.05	5.06	5.05	5.05	5.06	5.05	5.06	5.06	5.07	5.07
		-0.07	*-0.07*	*-0.06*	*-0.07*	*-0.07*	*-0.06*	*-0.07*	*-0.06*	*-0.06*	*-0.05*	*-0.05*
Land Use (acres)	2166.56	1993.88	1994.48	2013.12	1993.88	1994.48	2013.12	1987.58	2011.62	2011.62	2072.62	2072.62
		-172.68	*-172.08*	*-153.44*	*-172.68*	*-172.08*	*-153.44*	*-178.98*	*-154.94*	*-154.94*	*-93.94*	*-93.94*
Employment												
Construction (1000s of employee-years)	26.56	60.28	60.29	60.52	60.28	60.29	60.52	60.20	60.50	60.50	61.31	61.31
		33.72	*33.73*	*33.96*	*33.72*	*33.73*	*33.96*	*33.64*	*33.94*	*33.94*	*34.75*	*34.75*
O&M (1000s of employees)	42.64	41.78	41.80	41.83	41.78	41.80	41.83	41.78	41.83	41.83	42.03	42.03
		-0.86	*-0.84*	*-0.81*	*-0.86*	*-0.84*	*-0.81*	*-0.86*	*-0.81*	*-0.81*	*-0.62*	*-0.62*

(Note: Numbers in italics show how much each alternatives' impacts differ from the impacts estimated for the No-Action Alternative)



Power Contract Termination Dates
MW
3500
3000
2500
2000
1500
1000
500
0
1994
2000
2004
2008
2017
Pick-Sloan - 1,656 MW in 2000
CVP - 1,254 MW in 2004
Loveland - 693 MW in 2004
Salt Lake City - 1,398 MW in 2004
Parker-Davis - 217 MW in 2008
Boulder Canyon (Hoover) - 1,951 MW in 2017

June 8, 1994

Western Area Power Administration

CURRENT FIRM POWER CONTRACT SCHEDULES

Final Power Marketing Plan:	**Pick-Sloan Missouri Basin Program** For period 1985 - 2000 Published October 30, 1980
Contract Signature Date:	November 1980 extended original contracts New customers Nov 1980 - Jan 1981
Contract Effective Date:	Existing customers: same as original contracts New customers: after November 1, 1980
Contract Termination Date:	December 31, 2000
Final Power Marketing Plan:	**Loveland Area Projects** For period 1989 - 2004 Published January 31, 1986 Final allocations published April 1987
Contract Signature Date:	April - September 1987
Contract Effective Date:	October 1, 1989
Contract Termination Date:	October 1, 2004
Final Power Marketing Plan:	**Parker-Davis Project** For period 1987 - 2008 Published December 28, 1984 Final allocations approved May 1987
Contract Signature Date:	Based on termination dates of original contracts
Contract Effective Date:	Based on termination dates of original contracts
Contract Termination Date:	September 30, 2008
Final Power Marketing Plan:	**Boulder Canyon Project** For period 1987 - 2017 Published December 28, 1984
Contract Signature Date:	during January, 1987
Contract Effective Date:	January 1, 1987, which is date original contracts expire
Contract Termination Date:	September 30, 2017
Final Power Marketing Plan:	**Central Valley Project** * For period 1994 - 2004 Existing customers: October 5, 1992 New customers: June 28, 1993
Contract Signature Date:	Existing customers: October 1992 New customers: Sept 1993 - June 1994
Contract Effective Date:	Existing customers: Date of execution New customers: July 1, 1994
Contract Termination Date:	December 31, 2004

Final Power Marketing Plan:	**Salt Lake City Area Integrated Projects** For period from 1989 - 2004 Published February 7, 1986 Final allocations published April 2, 1987 **
Contract Signature Date:	March 1989
Contract Effective Date:	October 1, 1989
Contract Termination Date:	September 30, 2004

* Marketing of 420 MW pursuant to the 1994 CVP marketing plan. Remainder of CVP power is sold under contracts that became effective between 1952 and 1982. These are described in a separate document.

** Lawsuits filed October 31, 1986, and December 20, 1988. On February 22, 1989, the Judge combined lawsuits. Judge also required Western to include "reopener" clauses in contracts executed pursuant to this plan that will be exercized upon completion of a marketing plan EIS.

Western Area Power Administration

Central Valley Project
Current Long-Term Firm Power Contracts
NOT Based on the CVP 1994 Marketing Plan

Customer	Year Contract Effective	Year Contract Modified	Year Contract Terminates	Contract Length	Rate of Delivery (kW)
WATER/IRRIGATION DISTRICTS					**81,000**
Arvin Edison Water District	1966	1968	2004	38 yrs	30,000
Westlands Water District					50,000 1/
	1966	N/A	2004	38 yrs	5,475
	1966	1977	2004	38 yrs	4,100
San Juan Suburban Water District	2/	N/A	2004	21 yrs	1,000

Customer	Year Contract Effective	Year Contract Modified	Year Contract Terminates	Contract Length	Rate of Delivery (kW)
MUNICIPALITIES					**450,050**
City of Biggs	1967	1984 3/	2004	37 yrs	4,200
City of Gridley	1963	1984 3/	2004	40 yrs	9,400
City of Palo Alto	1963	1985 3/	2004	40 yrs	175,000
City of Redding	1964	1984 3/	2004	40 yrs	116,000
City of Roseville	1963	1985 3/	2004	40 yrs	69,000
City of Santa Clara	1965	1985 3/	2004	39 yrs	65,000
City of Shasta Lake	1965	1984 3/	2004	39 yrs	11,450
STATE OF CALIFORNIA					**3,000**
Sierra Conservation	1982	1986	2004	22 yrs	3,000

Customer	Year Contract Effective	Year Contract Modified	Year Contract Terminates	Contract Length	Rate of Delivery (kW)
RURAL ELECTRIC COOPERATIVES					**25,000**
Plumas-Sierra Rural Electric Cooperative	1964	1990 3/	2004	40 yrs	25,000
UTILITY DISTRICTS					**377,000**
Sacramento Municipal Utility District	1952	1983	2004	40 yrs 4/	360,000
Trinity 5/ County Public Utility District	1982	1987	2004	22 yrs	17,000
PUBLIC POWER AGENCIES					**14,000**
Calaveras 5/ Public Power Agency	1982	1989	2004	22 yrs	7,000
Tuolumne 5/ County Public Power Agency	1982	1990	2004	22 yrs	7,000

1/ The current rate of delivery to Westlands Water District is 50,000 kW. Westlands currently utilizes 9,575 kW for its own use and the remaining 40,425 kW are being used by other CVP customers on a withdrawable basis, as provided for in the 1981 Power Marketing Plan. The Rates of Delivery listed for the CVP customers receiving Westlands withdrawable power include their withdrawable power allocations.

2/ As a result of a long running dispute with the Bureau of Reclamation, Western agreed to provide San Juan Suburban Water District a retroactive allocation of CVP Preference power.

3/ Contracts renegotiated in settlement of the lawsuit entitled The City of Santa Clara v. Duncan et. al. Length of contracts vary due to date of execution of contracts to achieve a uniform termination date.

4/ Sacramento Municipal Utility District's (SMUD's) original contract was revised in 1954 and extended to 1994. As a result of the SMUD/WAPA Settlement Agreement in 1983, the contract was then extended to 2004. SMUD is entitled to a portion of CVP power through 12/31/2014.

5/ First Preference Rights for counties of origin extend beyond the current contract term.

June 8, 1994

Western Area Power Administration

1994 CENTRAL VALLEY PROJECT POWER MARKETING PLAN (CONTRACTS EXECUTED)

CUSTOMER	ALLOCATION (kW)
UTILITY DISTRICTS	
East Bay Municipal Utility District	1,965
Sacramento Municipal Utility District	1,000
FEDERAL	
U.S. Air Force:	**53,126**
Beale	21,575
Castle	0
McClellan	17,000
Onizuka	500
Travis	12,651
Travis Wherry Housing	1,400
Defense Logistics Agency (U.S. Army):	**83,000**
Parks Reserve Training Area, Dublin	500
Defense Distribution Depot (Sharpe Facility	3,800
Defense Distribution Depot (Tracy Facility)	4,000

U.S. Department of Energy:	
Lawrence Berkeley Laboratory	11,500
Lawrence Livermore National Laboratory	16,211
Site 300	2,500
Stanford Linear Accelerator Center	47,403
U.S. Navy:	57,797
Concord	2,188
Dixon	1,030
Lemoore	18,040
Moffett	2,000
Mare Island	20,388
Oakland	10,581
Skaggs	0
Stockton	3,570
Treasure Island	0
NASA-Ames	80,000
ICA, Dixon Relay Station	500

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WATER/IRRIGATION DISTRICTS

Banta Carbona	3,700
Broadview	500
Byron-Bethany	2,200
Delano-Earlimart	987
East Contra Costa	2,500
Glenn Colusa	3,343
James	987
Kern Tulare	987
Lindsay-Strathmore	987
Lower Tule River	1,965
Modesto	10,805
Patterson	2,000
Provident	750
Rag Gulch	500
Reclamation 2035	1,600
San Luis	6,650
Santa Clara Valley	987
Sonoma County	1,500
Terra Bella	987
Turlock	3,941
West Side	2,000
West Stanislaus	5,200

STATE OF CALIFORNIA	
California State University, Nimbus	40
Deuel Vocational Institution	1,700
Folsom Prison	2,300
Northern California Youth Center	1,700
Parks & Recreation	100
University of California, Davis	14,682
Vacaville Medical Facility	1,800
MUNICIPALITIES	
Alameda	21,145
Healdsburg	3,361
Lodi	13,836
Lompoc	5,317
Santa Clara	11,532
Ukiah	8,933

NEW CUSTOMERS

City of Avenal	622
Bay Area Rapid Transit District	4,000
Cawelo Water District	500
Lassen Municipal Utility District	3,000

**STATEMENT OF CONGRESSMAN BOB SMITH
OVERSIGHT AND INVESTIGATIONS SUBCOMMITTEE
HEARING ON WESTERN AREA POWER ADMINISTRATION
JUNE 16, 1994**

Mr. Chairman,

I apologize that my schedule won't permit me to stay and listen to this important testimony today.

As a representative from the Pacific Northwest, the survival of our economy largely revolves around the Bonneville Power Administration, which is the power marketing authority in that area.

I know that many of my colleagues on this side of the committee room represent constituents who are as equally dependent on competitive power rates from Western Area Power Administration. I'm going to defer to them in helping the Chairman craft a long-term policy to the question of who is going to get WAPA power and for how long.

I thank the Chairman.

Statement
of the
Honorable Barbara F. Vucanovich
on
Western Area Power Administration Proposals

Committee on Natural Resources
Subcommittee on Oversight & Investigations

June 16, 1994

Mr. Chairman, thank you for convening this oversight hearing into the proposals of the Western Area Power Administration (WAPA) for power allocations and contract renewals. My constituents in southern Nevada use electricity generated by the Bureau of Reclamation in both the Boulder Canyon and Parker-Davis Projects. Hydroelectric power is certainly not completely without environmental costs, but it seems to be way ahead of competing forms of power generation. The electric utilities which serve my constituents naturally want to continue to contract with WAPA under favorable terms, but they also want to participate in oversight of Bureau of Reclamation spending at Hoover Dam and elsewhere because of the ultimate pass-through of these costs to the electric customer.

It's no secret the Bureau is nearly finished constructing a "Taj Mahal" visitor center at Hoover which has far exceeded initial cost estimates. In fact, I'm told it will exceed the cost of the dam itself when constructed sixty years ago, when compared without respect to inflation. This outlandish overrun must not be allowed to happen again at Hoover or elsewhere. The bulk of the costs of the visitor center won't be borne by WAPA customers until beginning next year, when further rate increases will be necessary. The small power districts in southern Nevada that serve this hydropower to their rural customers are the entities least able to bear the steep rate increases forecasted yet have the fewest alternatives as well.

So yes, I want to see Nevada get its fair share of project power. That share was set at one-third of the Boulder Canyon Project output when its reauthorization was enacted in Congress a decade ago. While we may have been unable to avail ourselves of the full load at that time, I certainly don't want a repeat of the 1922 Colorado River Compact when Nevada settled for only a small fraction of the river's flow because Las Vegas and surrounding communities were sleepy little byways at the time. Nevada will be able to use one-third of Hoover's electric output before we know it and WAPA contracts to be renewed in the year 2017 ought to reflect that fact.

But, Mr. Chairman, 2017 is over twenty years away so WAPA has plenty of time to plan for this demand compared to, say, Pick-Sloan contracts due up in less than six years. In the meantime, let's see to it the power using entities have proper opportunity to review WAPA and Bureau of Reclamation proposals that will add to their power bills and scrutinize the books before another "Taj Mahal" is built.

CREDA

COLORADO RIVER ENERGY DISTRIBUTORS ASSOCIATION

ARIZONA
Arizona Municipal Power Users Association
Arizona Power Authority
Arizona Power Pooling Association
Irrigation and Electrical Districts Association
Navajo Tribal Utility Authority (also New Mexico, Utah)
Salt River Project

COLORADO
City of Colorado Springs
Platte River Power Authority
Tri-State Generation & Transmission Cooperative (also Nebraska, Wyoming)

NEVADA
Colorado River Commission of Nevada
Silver State Power Association

NEW MEXICO
Farmington Electric Utility System
Plains Electric Generation & Transmission Cooperative (also Arizona)
City of Truth or Consequences

UTAH
Intermountain Consumer Power Association (also Arizona, Nevada)
City of Provo
Strawberry Electric Service District
Utah Municipal Power Agency

WYOMING
Wyoming Municipal Power Agency

CLIFFORD BARRETT
Executive Director
One Utah Center, Suite 900
201 South Main St.
Salt Lake City, Utah 84111
Phone 801-350-9090
Fax 801-350-9051

June 21, 1994

The Honorable Peter A. DeFazio
United States House of Representatives
Washington D.C. 20515

Dear Congressman DeFazio:

It was a pleasure to testify at the Committee on Natural Resources Subcommittee on Oversight and Investigations hearing on June 16, 1994. We especially appreciate your involvement and dialogue with the Western customer panel and with Deputy Secretary White. We are writing to supplement the answers given by Deputy Secretary White to some of your questions. The Colorado River Storage Project (CRSP) customers have answers to these questions that are significantly different from the other Western projects.

Relative to the Western's power purchases to firm up the hydropower resource, you asked Mr. White if customers could be given the choice of buying the power themselves instead of Western buying power for all of their customers. This very issue has been a point of discussion for some time between the CRSP customers and Western. When changes to Glen Canyon Dam operations were first initiated in the fall of 1991, CREDA raised this issue with Western in regard to purchases of power to replace that lost by operational changes. The result is that CRSP customers have the option of either buying the power themselves or having Western buy it for them. This option is contained in contract amendments offered to all CRSP customers. This option was negotiated specifically to solve the problem related to interim operations at Glen Canyon and expires when final operational changes are adopted at the conclusion of the EIS process.

The Grand Canyon Protection Act requires Western to look at ways to replace the generation lost through changes at Glen Canyon. As a part of that process we are working with Western to have a similar customer purchase option ready when long term operational changes are adopted.

You also asked Mr. White some questions concerning level of maintenance and ability to make system improvements in the face of reduced availability of funds for such work. We would like to point out that operation and maintenance of the CRSP power features is done with power revenues and actually funded by the power users on a "pay as you go" or revolving fund basis. One result of this funding mechanism is that CRSP power features are maintained at an acceptably high level and system improvements are done on a timely basis. For example all of the CRSP generating units have or are being rewound and uprated to produce more power. This a very different situation than exists on many other projects.

We hope these additional comments are useful to you as you consider Western's power marketing program. If you have questions please feel free to call me at 801-350-9090.

Sincerely,

Clifford Barrett
Executive Director

CB:mg

IRRIGATION & ELECTRICAL DISTRICTS ASSOCIATION OF ARIZONA

W.A. DUNN
CHAIRMAN OF THE BOARD

R. GALE PEARCE
PRESIDENT

R.D. JUSTICE
VICE-PRESIDENT

SUITE 204
2001 NORTH THIRD STREET
PHOENIX, ARIZONA 85004-1472
(602) 254-5908

CLYDE GOULD
SECRETARY-TREASURER

ROBERT S. LYNCH
ASSISTANT SECRETARY-TREASURER

<u>TELECOPIED AND MAILED</u>

June 29, 1994

Hon. George Miller, Chairman
House Natural Resources Committee
Room 1324
Longworth House Office Building
Washington, D.C. 20515

Re: Subcommittee on Oversight and Investigations Hearing on Western Area Power Administration Power Allocation, June 16, 1994

Dear Mr. Chairman:

I had the privilege of attending the subcommittee hearing you chaired on June 16th and listening to the testimony and the questions from the members of the panel and responses from the witnesses. Our Association comments on the draft environmental impact statement on Western's Energy Planning and Management Program were entered into the record by Cliff Barrett, the witness for the Colorado River Energy Distributors' Association (CREDA). It is not my intent to repeat those comments here. However, I was struck by the misimpression created by certain other witnesses about the true state of affairs in public power allocations by Western, at least as members of our Association have experienced it. Three significant mistaken views could be taken from the hearing.

First, one could conclude from Reclamation Commissioner Beard's and Bruce Driver's testimony that more fossil-fuel electricity will be generated if Western buys supplemental power for its customers rather than forcing the customers to find their own supplement power. Nothing could be further from the truth. Our members, like most of Western's small customers, have supplemental contracts with one or more generating utilities in our area. If Western can't be relied upon, we must fall back on these fossil-fuel and nuclear-based sources. Our members have neither the capital nor the staff to do expensive demand-side management programs even if the technology was presented to us. Nor have we easy access to emerging technology. Instead, we rely significantly upon Western to gain us access to technology and information about it.

Hon. George Miller
June 29, 1994
Page 2

Second, Bruce Driver in his testimony infers that somehow individual small public power entities can magically find and use new types of resources and new technologies in spite of their limitations in funding, staff and expertise. He further supposes that if Western purchases and supplies supplemental power that its customers will neglect or refuse to explore demand-side management opportunities. Mr. Driver has it exactly backwards. It is Western's presence in the market and its transmission system that perfectly positions it to be the driving force in the public power network it serves in funding, accessing and delivering new resources and promoting new technologies. It is a simple matter of recognizing the basic economic principle of economies of scale.

Third, from listening to the testimony and reading the reports of the hearing, one could conclude that Western has placed impediments in the path of Native Americans which prevent them from sharing in the benefits of public power generated at federal hydropower facilities. That is just plainly not true. In Arizona, for instance, seven tribal reservations have allocations of federal hydropower from the Colorado River Storage Project (CRSP) and/or the Parker-Davis Project, either directly or through the Bureau of Indian Affairs. These allottees include one of our own members, the Ak-Chin Indian Community, which holds a CRSP allocation. We are also informed that some 110 megawatts of CRSP power reserved for project use has not been allocated. Certainly, the relatively small amount of power identified by the Ute Mountain Ute Tribe for its needs on its reservation could be considered within further allocation of that rather substantial resource.

Thank you for the opportunity to submit these additional comments. I would ask that these additional comments be made part of the hearing record.

Sincerely,

Robert S. Lynch
Asst. Secretary/Treasurer

RSL:psr

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200

June 16, 1994

Chairman George Miller
House Natural Resources
Subcommittee on Oversight and Investigations
1324 Longworth H.O.B.
Washington D.C. 20515

OTTER TAIL
Power Company

Dear Chairman Miller,

Enclosed for the consideration of the Subcommittee is the testimony of Mr. Warren Nye, which he would like to have entered into the record of today's hearng on the proposed WAPA allocation and contract extensions of over 7000 MW of power.

Mr. Nye is a retired employee of Otter Tail Power Company who was active for many years in the electric industry, and he is familiar with every aspect of power from stringing farm lines to negotiating contracts with WAPA.

I am a former Chair of the Minnesota Public Utilities Commission, and have represented consumers in numerous regulatory matters. I believe you will find Mr. Nye's ideas to be provocative and innovative, and as he is an octegenarian they are founded in the wisdom of experience.

Mr. Nye has been communicating with Senator Paul Wellstone about this idea, and Congressmen Collin Peterson and Bruce Vento were helpful to me in finding the route to your committee. I truly hope you will give full consideration of the idea of using federal preference power to help the poor and the elderly instead of distributing the federal largesse on the ad hoc basis of who was able to get in line a generation or more ago.

Thank you for your consideration of Mr. Nye's testimony.

Sincerely yours,

Katherine E. Sasseville

Katherine E. Sasseville,
General Counsel

Att'n : Linda Stevens

An Equal Opportunity Employer

Route 2
Battle Lake, Minnesota 56515
June 16, 1994

Chairman George Miller
House Natural Resources
Subcommittee on Oversight and Investigations
1324 Longworth H.O.B.
Washington DC 20515

Dear Chairman Miller:

It is unfair that the poor residential or farm electric customer served by most systems is not receiving any benefits from federal hydro electric generation and only a small portion of the benefits on other--"Preference"--systems.

The benefits go primarily to industries, shopping malls, and those well able to pay market prices. In Minnesota only a small portion of the REA cooperatives and municipal electric systems and none of the investor-owned systems receive federal energy and those receiving the energy spread the benefits to all customers, when the poor of all the systems should get the benefits.

A malting plant in Moorhead gets this federal subsidy while the poor in Virginia get none. The well-to-do from the Twin Cities get a federal subsidy for their lake homes by Alexandria while the poor in Battle Lake get none.

The "Preference" program for federal hydro generation started before the interconnection of transmission systems in the United States and Canada and before computer billing. Now it's possible to schedule the federal energy to the poor with the delivery system receiving only their transmission and distribution costs.

This would supplement the LIHEAP program which is underfunded. All the federal electric energy should be received for the poor regardless of their present supplier.

The government wouldn't be in the retail business; just wholesale as now. The delivering utility would have a low income rate with the production portion of its rate removed and replaced by the much lower wholesale rate of the government.

Sincerely,

Warren Nye

Warren Nye

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5555

EEI **EDISON ELECTRIC INSTITUTE**

THOMAS R. KUHN
President

June 23, 1994

The Honorable George Miller
Chairman
Subcommittee on Oversight and Investigations
Committee on Natural Resources
U.S. House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Enclosed is a statement by the Edison Electric Institute, which we request be included in the record for your Subcommittee's hearing on the Western Area Power Administration's hydroelectric power allocation, which was held on June 16, 1994.

Should you or your staff have any comments or questions, please call me at (202) 508-5555 or Kathy Steckelberg, Director, Government Relations, at (202) 508-5478. We appreciate the opportunity to submit comments on this important issue.

Sincerely,

Thomas R. Kuhn

TRK:ks

Enclosure

cc: The Honorable Robert F. Smith
Ranking Minority Member

STATEMENT SUBMITTED BY THE

EDISON ELECTRIC INSTITUTE

TO THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

HOUSE NATURAL RESOURCES COMMITTEE

U.S. HOUSE OF REPRESENTATIVES

ON ALLOCATION OF

THE WESTERN AREA POWER ADMINISTRATION'S

HYDROELECTRIC POWER

The Edison Electric Institute (EEI) appreciates the opportunity to submit testimony on the Western Area Power Administration's (WAPA) proposed allocation of its hydroelectric power. EEI is the association of investor-owned electric utility companies. EEI's member companies generate 78 percent of our country's electricity and serve 76 percent of all the nation's ultimate customers.

Section 114 of the Energy Policy Act of 1992 (EPAct) directs WAPA to require each customer purchasing electricity under a long-term firm power service contract to implement integrated resource planning (IRP). In March 1994, WAPA issued an Energy Planning and Management Program draft environmental impact statement (EIS) which addressed IRP issues, but also proposed a number of Power Marketing Initiative (PMI) alternatives featuring significant extensions of existing power contracts. The PMI Extension Alternatives would extend power contracts by as long as 35 years, while the PMI Limited Extension Alternatives would extend them by 10 years.

EEI believes that the heavy reliance upon long-term contracts which is postulated by WAPA is inconsistent with current IRP practices and with utility planning in the current environment. EEI submitted comments to WAPA on the draft EIS, strongly supporting inclusion of one of the PMI non-extension alternatives in WAPA's Energy Planning and Management Program, which would allow WAPA to market power on a project-specific basis. EEI does not believe that adoption of either the PMI Extension Alternatives or the PMI Limited Extension Alternatives is necessary for WAPA's customers to establish effective IRP practices.

The electric utility industry is entering a period of unprecedented change in response to the Energy Policy Act of 1992 (EPAct), other federal and state policies and changing customer needs. These factors have accelerated the competitive forces affecting the electric utility industry and have induced utilities to develop strategies for the transition to more open, competitive markets. As a result of this transition, the utility industry may look significantly different in five to ten years.

These competitive forces are likely to have a major impact on utilities' IRP practices. There are several potential implications, including increasing emphasis on optimizing short- and medium-term planning decisions and relying on a portfolio of demand-side and supply-side options. In current circumstances, relying primarily upon long-term power contracts reduces a utility's flexibility to react to changing market conditions and may reduce incentives to consider demand-side management programs, as well as the other factors identified as part of IRP in the EPAct. In fact, state regulatory commissions in New England, New York and California, among others, are urging--or requiring--utilities to either buy out or buy down long-term contracts because they are inflexible and substantially exceed the market price of power.

Currently, regulatory IRP processes are guided by statutory or administrative rule in 34 states. In addition, many other states conduct processes addressing IRP issues, e.g., rate cases or plant siting proposals. Long-term planning horizons for formal state regulatory IRP filings generally range from 10 to 20 years. To reflect changes in the market, utilities generally update their filed plans on a biennial basis. Short-term utility action plans filed in conjunction with long-range IRPs usually focus on a three- to five-year range. It is these short-term action plans which govern actual investment in resource acquisition. In some cases, utilities file annual reports with state commissions describing key milestones or other accomplishments associated with actions taken in conjunction with approved plans. The attached table shows state filing requirements for IRP planning horizons and update periods.

There are no state IRP processes that contain explicit, objective criteria requiring long-term planning certainty with regard to supply and price. In fact, the trend is clearly moving away from the relative stability associated with exclusive franchise monopolies. Many state commissions are recognizing the rapidly changing nature of the industry and actively discouraging utilities from incurring costs associated with acquisition of long-lived assets and other resources.

Furthermore, no utility IRPs are required to specifically identify and match load forecasts with corresponding commitments to the resources which are anticipated to meet load throughout the duration of the entire long-range planning horizon. In most cases, state commissions are finding in state processes that load forecasts and resource plans are imprecise for periods beyond a "critical planning path," which is generally a period of two to seven years, depending on individual utility circumstances and the types of resource alternatives under consideration.

The increasingly competitive trend in the industry requires shorter strategic planning horizons for utilities to compensate for increased business and financial risks and to minimize short-run marginal costs. Regardless of the type of ownership, recent trends indicate a preference for construction of short lead-time combustion turbines or combined cycle units fired by natural gas or multi-fuel capable designs in recognition of the significant carrying charges associated with more capital intensive projects. Moreover, terms for purchased power contract periods generally range from 1-20 years, trending recently toward shorter periods, e.g., less than 10 years. Considering these trends, the contract extension periods chosen by WAPA for the Extension Alternatives or Limited Extension Alternatives are unnecessarily long to effectuate IRP.

Overall, the planning objective in the U.S. electricity sector is moving from minimizing long-run average costs for an exclusive franchise monopoly toward minimizing short-run marginal costs in a market with intense wholesale bulk power competition. Contract terms for purchased power agreements, regulatory trends in state IRP processes, and approvals for "special" retail prices which approximate competitive market alternatives for some customers confirm the trend.

EEI believes that the large number of contract extension alternatives in WAPA's draft EIS are not true alternatives at all from an IRP perspective and that WAPA could delete many of these alternatives from the EIS. In its comments on the draft EIS, EEI urged WAPA to include one or more PMI non-extension alternatives in its Energy Planning and Management Program in order to more accurately replicate current trends and the evolving nature of IRP practices. In addition, EEI recommended that at least one of these alternatives require WAPA's customers to seek competitive bids on the primary part of their power purchases.

Congress has mandated that WAPA's customers must undertake IRP. EEI believes that reliance on long-term contract extensions would frustrate the implementation of that mandate.

Thank you again for the opportunity to submit testimony on this important issue.

TESTIMONY
WILLIAM KINDLE, PRESIDENT
ROSEBUD SIOUX TRIBE

REPRESENTING ROSEBUD SIOUX TRIBE
AND THE TRIBES OF THE MISSOURI RIVER BASIN

Respecting
House Natural Resource Committee Oversight Hearing on
Western Area Power Administration Allocation of
Federal Power

Mr. Chairman and Committee Members:

The Rosebud Sioux Tribe and the Indian Tribes of the Missouri River Basin appreciate your willingness to meet with their representatives today. We are here to voice our concerns on the current allocation of process of western area power administration.

1. The Western Area Power Administration regards the Indian tribes as "preference" entities entitled to the sale of low-cost federal energy. Federal power cost approximately 10 mils ($0.010) per kilowatt hour compared with commercial power costs of about 45 mils ($0.045) per kilowatt hour.

2. The demand for power by preference customers exceeds the supply of federal hydropower produced by the mainstem dams. Therefore, the Western Area Power Administration has adopted additional criteria for sale of the available supply to preference customers. That criteria virtually excludes the tribes from receiving direct allocations of preference power. The principle criteria that excludes the Indian tribes from a direct allocation of "preference" power is utility status. Few, if any, tribes quality as "utilities", although all tribes quality as "preference" customers.

3. The Western Area Power Administration will not market "preference" power to non-utilities. Involvement of the public in a power marketing process, will not result in changes in the requirement of utility status for tribes to receive an allocation of "preference' power.

4. Western Area Power Administration will decide within the next 6 to 18 months the proportion of the sale of preference power to old utility customers. A decision will be made to re-market from 70 to 98 percent of the available power to old customers. The 2 to 30 percent of power not immediately re-allocated to old customers will be marketed as follows:

   a. Part will be marketed to old customers who demonstrate initiative in the conservation of electricity.

   b. Part will not be allocated to either old or new customers depending on reduction of available resource stemming from changes in operating procedures for the mainstem reservoirs that do not permit as much firm hydropower production.

c. Part may be allocated to new customers.

With clarity and precision the Western Area Power Administration demonstrated in August 28, 1991, meeting in Billings that the on-going public process for power marketing is not a public process. Only utilities, not the public, are truly involved. Old customers of the Western Area Power Administration will continue to dominate the power marketing process unless there is a demand for change by the tribes.

Demands to change the Western Area Power Administration marketing criteria will go unheeded by that agency. We seek a Legislative mandate that would direct the Secretary of Energy to allocate as much as 25 percent of the firm hydropower energy of the Missouri River mainstem dams to the collective tribes. It is within the Indian Reservations of the Missouri River Basin that an allocation of low-cost federal energy can have the greatest positive impact. Historically, the Reservations have been denied any effective participation in the low-cost federal hydropower and all other Missouri River Basin Pick-Sloan benefits that were approved by Congress in the 1944 Flood Control Act. The Missouri River Basin Program was built on Indian land and vested Winters doctrine water right, but the tribes have not participated in the benefits of the project.

The 1944 Flood Control Act (58 STAT 887) approved the Missouri River Basin Pick-Sloan Plan for irrigation, navigation, hydropower and other purposes. The Bureau of Indian Affairs, acting on behalf of the Indian of the Missouri River Basin, supported the legislation on the following grounds:

"Insofar as the Indian irrigation and power interests are concerned, the report [Senate Document 191] seems to give them adequate consideration."

We respectfully submit that the report may have given the Tribes adequate consideration, but the implementation of plans approved by the Act have given the Tribes virtually no consideration. Little irrigation development identified by the Missouri River Basin Pick-Sloan Plan has been implemented on Indian reservations. Only small amounts of pumping power have been made available to some tribes for limited irrigation. The tribes, which qualify as "preference" bodies, have never been able to contract with the Western Area Power Administration for low-cost federal hydropower.

The Western Area Power Administration, federal marketing agency for Missouri River Basin Pick-Sloan hydropower, has recently initiated a "public" process for re-contracting of Missouri River Basin Pick-Sloan power. Existing contracts for the sale of "preference" power will end in year 2000, and Western is taking steps to re-contract the power. The tribes of the Missouri River Basin seek a direct allocation of 25 percent of the power to be marketed. An allocation of this magnitude would raise electrical rates to customers in the rural electrical cooperatives, principle recipients of the power at present, by an estimated 3.6 percent.

The Indian tribes are now participating in the "public" process of the Western Area Power Administration for re-contracting of this valuable federal asset. It is important to the Indian tribes because federal power is sold at a rate of approximately 10 mils ($0.010) per kilowatt hour while the rural electrical cooperatives that sell electricity to the tribes and their membership charge from 35 to 45 mils ($0.035 to $0.045) per kilowatt hour.

We are shocked to find that the "public" process is not truly public. Western intends to market from 70 to 98 percent of the preference power to existing customers, thereby excluding the tribes and others from consideration as new customers. Of the 2 to 30 percent of the present power resource to be handled differently, part will be marketed to old customers that demonstrate initiative in energy conservation, part will be removed from the marketing process due to reduction in the firm power resource and the remaining will be contracted to new customers. Any new customers must be preference customers as defined by the 1944 Flood Control Act. Western agrees that the tribes quality as preference customers. But in addition to preference status, any new customer must also qualify as a "utility". With Minor exception, the tribes do not qualify as utilities, and we are effectively excluded from the marketing process.

In the near future Western intends to determine on the amount of power made available to new "utility" customers. Your assistance is urgently requested by the tribes of the Missouri River Basin. We petition you to hold a hearing in the current session of Congress to address the ways and means of meaningful tribal participation in the direct purchase of low-cost federal energy produced by the Missouri River Basin Pick-Sloan program. Legislation may be our only avenue. We are hopeful you would sponsor legislation that would direct the Secretary of Energy to allocate low-cost federal hydropower existing transmission and distribution systems that serve the Reservations.

One of the principle provisions of the 1944 Flood Control Act with regard to electric power and energy has never been used to the advantage of the Indian tribes. That provision is as follows:

"The Secretary of the Interior is authorized from funds to be appropriated by the Congress, to construct or acquire, by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at such projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal government, public bodies and cooperatives and privately owned companies." (SEC. 5, 58 STAT 887, p. 890).

We believe that wheeling is a sensible mechanism for making wholesale, preference power available to the Tribes at this point in time. If wheeling is not workable, acquisition of transmission and related facilities (authorized by the language set forth above) may be necessary.

Many of the Indian tribes contributed extensive tracts of land for the construction of the Missouri River Basin Pick-Sloan dams and reservoirs. All of the tribes have vested Winters doctrine rights to the use of water in the Missouri River and its tributaries that are being utilized to generate federal hydropower. Our contributions to the project are great, but our benefits from the project are virtually none.

We seek support in developing legislation which we believe is clearly needed if we are to participate directly in the benefits of low-cost federal hydropower on the Missouri River. Thank you for allowing this time to express our concerns.

D R A F T Resolution No. 94-127 D R A F T

WHEREAS, the Rosebud Sioux Tribe is a federally recognized Indian Tribe organized pursuant to the Indian Reorganization Act of 1934 and all pertinent amendments thereof; and

WHEREAS, the Rosebud Sioux Tribe is governed by a Tribal Council made up of elected representatives who act in accordance with the powers granted to it by it's Constitution and By-Laws; and

WHEREAS, the Mni Sose Coalition was established by Missouri River Basin Tribes to, not only, protect and preserve their rights to the use of Missouri River water, tributaries and groundwater located on, near and under their respective reservation, but, also to address in a broad and comprehensive way all issues and matters related to their Indian Winters reserved water rights; and

WHEREAS, the Mni Sose Coalition--at the request of member Tribes who are recognized by Western Area Power Administration (WAPA) as preference customers eligible to receive low-cost federal hydropower Allocation process were reviewed; and

WHEREAS, in the year 2000. WAPA will re-allocate under long-term contracts all hydropower generated at six mainstem dams on the Missouri River and is now proceeding with implementation of policies and criteria that will determine which preference customers will receive low-cost power from the Missouri River Basin Pick-Sloan Program; and

WHEREAS, under these policies it is clear that Indian Tribes, who are recognized as preference customers and also have the greatest need for low-cost power, will not be considered by WAPA in the current hydropower re-allocation process unless they are directed by Congress and Secretary of Energy to do so; and

WHEREAS, to ensure that Tribes in the Missouri River Basin are provided the opportunity to participate in and receive an allocation of low-cost hydropower, the Rosebud Sioux Tribe pursuant to Public Law 102-575, the Reclamation Project's Authorization and Adjustment Act of 1992, submitted a request to the Mni Sose Coalition Board of Directors, on June 15, 1993, for support to seek Congressional Oversight Hearings to address relevant aspects of WAPA's Hydorpower Allocation Process; now

THEREFORE BE IT RESOLVED, that the Rosebud Sioux Tribal Council hereby requests Mni Sose Inter-Tribal Water Rights Coalition to support the Rosebud Sioux Tribe in securing Congressional Oversight Hearings to address concurrently with the Oglala Sioux Tribe: (1) the need for low-cost electrical energy on the Rosebud and other Indian Reservations in the Missouri River Basin; (2) the need for comprehensive re-evaluation of the criteria for allocating Pick-Sloan power resources by the Western Area Power Administration and; (3) the need for acquisition of the local rural electrical cooperatives, in part or in whole, or alternatively the need to transport low-cost federal energy across the transmission and distribution systems of the local rural electrical cooperatives for the benefit of the Rosebud Sioux Tribe and the membership of all Missouri River Basin Tribes; and

BE IT FURTHER RESOLVED, that the Board of Directors for the Mni Sose Inter-Tribal Water Rights Coalition hereby directs the Executive and Assistance Directors for the Coalition to take all appropriate actions necessary to ensure that the Rosebud Sioux Tribe and other interested Missouri River Basin Tribes are given the opportunity to present their en;rgy concerns at a Congressional Oversight Hearing; and

BE IT FURTHER RESOLVED, that the Coalition staff, in close coordination with the Board of Directors and Executive Committee, are further directed to contact and communicate with all Missouri River Basin Tribes and other Indian organizations to secure their support for Oversight Hearings on WAPA's Hydropower Allocation Process; and

BE IT FURTHER RESOLVED, that the President and the Secretary of the Rosebud Sioux Tribe are hereby authorized and directed to sign this resolution for and on behalf of the membership of the Rosebud Sioux Tribe.

CERTIFICATION

WILLIE KINDLE
President

NORMAN WILSON
Vice-President

Rosebud Sioux Tribe

ROSEBUD INDIAN RESERVATION
ROSEBUD, SOUTH DAKOTA 57570

P.O. BOX 430
Phone 605-747-2381 — Fax 605-747-2243

CYNTHIA L. GARY
Treasurer

GERRI GORDON
Secretary

TODD BEARSHIELD
Sergeant-at-Arms

June 30, 1994

Honorable George Miller, Chairman
House Natural Resources Committee
1324 Longworth HOB
Washington, DC 20515

Dear Mr. Chairman Miller:

The Rosebud Sioux Tribe joins other tribes of the Missouri River Basin in support of testimony offered by Wilbur Between Lodges, President of the Oglala Sioux Tribe. The statement of Mr. Between Lodges was presented by Paul Little, one of the panelists at your June 16, 1994 hearing.

The Rosebud Sioux Tribe supports a reservation of not less than 25% of Western's power for Tribes (1) to address the need for low-cost preference power on the Reservations for residential, industrial and irrigation purposes and (2) to protect and preserve our Winters doctrine rights which are being diminished by state court adjudication and negotiation under the threat of adjudication. In the latter case, our plan is reasonable and progressive. It is our alternative to the ongoing 19th-century-style encroachment on the Indian people which involves McCarran amendment adjudication and negotiation under the threat of adjudication.

The Rosebud Sioux Tribe and others are hopeful that we can be afforded sufficient time and opportunity to heard on the two basic propositions presented in Mr. Between Lodges' statement as briefly summarized above.

For our part, the Rosebud Sioux Tribe has offered to analyze the impact of a reservqtion of 25% of Western's power on the rates of consumers served by rural electrical cooperative customers of Western. Our statement, which is attached, shows that the avewrage consumer served by a Western REC customer will experience a 2.5% increase in rates if Western withdraws the power sopught by the Missouri River Basin tribes.

I trust that our statement has been filed timely and can be included in the record of your most important oversight hearing. I personally attended the hearing and appreciate your effort to arrive at a sensible federal policy for allocation of Western power.

Sincerely,

William Kindle

William Kindle
President

STATEMENT OF WILLIAM KENDALL, PRESIDENT
ROSEBUD SIOUX TRIBE

Respecting
Impact of 25% Reservation of Western Firm Wholesale Power for Indian Tribes
on Consumers Served by RECs that are Existing Western Customers
Missouri River Basin Pick-Sloan Project

In 1985, a year not untypical of present practices, Western marketed 12,289,421,000 kilowatt hours of Pick-Sloan energy (Billings and Loveland) and derived $112,734,000 in power revenues averaging 9.173 mills per kilowatt hour. Twenty six (26) rural electrical cooperatives purchased 5,309,645,000 kilowatt hours, 43% of the total, at an average cost of 8.144 mills per kilowatt hour.

Municipalities purchased 3,900,188,000 kilowatt hours. Over 200 municipalities inside the Missouri River Basin and outside (47 municipalities are in Minnesota) purchased part of their power supply from Western. Public and private utilities purchased most of the balance of Western's power, 3,079,588,000 kilowatt hours.

Not all power purchased by the REC's is Western power. In 1986, a year chosen for availability of data (not selectivity), the REC customers of Western purchased 6,653,824,000 kilowatt hours from Western (up slightly from 1985), purchased 10,835,373,000 kilowatt hours from other suppliers and generated 21,215,165,000 kilowatt hours. Of the total 38,704,362,000 kilowatt hours, 17.19% was purchased from Western. Table 3, at the close of my statement, summarizes.

If in 1986 Western had supplied 25% less power (4,990,368,000 kilowatt hours), it would have been necessary for the REC's to forego 8.211 mill per kilowatt hour power and replace it with 37.878 mill per kilowatt hour power (from supplies other than Western) or with 41.980 mill per kilowatt hour power (from generation by Basin Electric or others). Choosing the higher replacement cost of 41.980 mills per kilowatt hour would require Western customers to increase their power expenditures from $1,355,670,346 to $1,411,837,000 (Table 1). Costs of power would increase from 35.026 to 36.477 mills per kilowatt hour, a 4.14% increase.

The Rosebud analysis confirms the statement of President Between Lodges that 25% withdrawal of Western power would increase rates by a small amount, on the order of 2%.

Creativity should govern in the amount of withdrawal from existing Western customers. It is not asserted here that 25% withdrawal should be from each existing customer or class of customer (REC, municipality, public utility, private utility). We simply assert that an average 25% withdrawal from existing REC customers would not have a profound or significant effect on consumer rates.

The Western customer REC's of Pick-Sloan oppose allocation of any amount of power to any new users on the basis that their rates would be raised, however slightly. Midwest Electric Consumers Association opposed the electrical power provisions of HR 3954, an act to expand the Mni Wiconi Rural Water Project, which will deliver safe and adequate drinking water to the Rosebud, Lower Brule and Oglala Sioux Tribes and to the West River and Lyman-Jones rural water systems. The expanded project will require an additional 2 megawatts of Western's firm, wholesale power throughout the year. Midwest opposition to HR 3954 caused the electrical provisions for Western power to be dropped in S. 2066. Unless the power provisions are deleted from the final versions of the House and Senate bills, Midwest made it clear that our drinking water project would not advance in this session of Congress and would be questionable in future sessions. Because our people desperately need a drinking water solution, we cannot risk a major delay caused by Midwest.

The Rosebud Sioux Tribe has ordered Freedom of Information Act data on Pick-Sloan RECs from REA for 1993. We trust that the Committee will accept our analysis and statement for the hearing record, but permit us to work with Western, the RECs, municipalities and others to improve our analysis if elements of the reasoning require refinement and to bring our data closer to the present. Due to the press of time following notice of the oversight hearing, we relied on data in our files from the mid-1980's.

Purchases From All Suppliers (1988)

Customer	REA Borrower	KWH (000)	Revenue $	Average Cost (mills/KWh)	Supplier
East River Electric Power	SD 43				
		714,699	36,435,895	51.039	Basin Electric
		--	44,354	--	Traverse Electric
		658,051	4,989,720	6.833	Western
		1,372,750	41,363,615	30.133	Subtotal
		1,361,489	54,356,691	40.833	Total Sales
		N/A	N/A	N/A	Generation and Other
Grand Electric Power	SD 40				
		42,744	2,116,262	48.379	Basin Electric
		--	1,830	--	Upper Missouri G&T
		34,692	282,834	8.107	Western
		3	38	12.800	Cogeneration
		78,438	2,399,301	30.508	Subtotal
		71,693	4,376,864	61.048	Total Sales
		N/A	N/A	N/A	Generation and Other
Itasca Mantrap CPA	MN 83				
		44,393	2,221,198	50.035	United Power Assoc.
		22,989	288,732	12.570	Western
		67,382	2,509,930	37.268	Subtotal
		62,696	4,254,930	67.898	Total Sales
		N/A	N/A	N/A	Generation and Other
KEM Electric	ND 27				
		18,114	1,072,424	59.259	Basin Electric
		33,561	270,326	8.054	Western
		51,675	1,342,760	26.006	Subtotal
		46,426	3,203,830	69.040	Total Sales
		N/A	N/A	N/A	Generation and Other
L&O Power Cooperative	IA 86				
		65,152	3,567,847	54.762	Basin Electric
		69,930	466,854	6.765	Western
		134,082	4,034,681	30.079	Subtotal
		133,387	4,950,689	37.081	Total Sales
		N/A	N/A	N/A	Generation and Other
Minnesota Valley	MN 63	181,981	10,833,423	36.654	Cooperative Power Assoc.
		181,381	10,833,423	36.654	Subtotal
		177,838	14,682,046	82.309	Total Sales
		N/A	N/A	N/A	Generation and Other
Minnkota Power	ND 20				
		1,373,855	18,807,529	13.692	Manitoba Hydro
		85,571	1,215,625	14.854	Mid Continent Area Power Pool
		734,654	21,377,316	29.098	Square Butte Electric
		684,425	6,076,098	8.388	Western
		473,007	22,762,846	48.122	Miscellaneous
		5,289	80,932	15.298	Cogeneration
		3,329,612	67,800,833	20.900	Subtotal
		4,496,988	98,862,328	21.996	Total Sales
		1,288,176	31,460,812	24.808	Generation and Other
Nor-Gran-Sou Electric	ND 25				
		30,399	2,173,855	54.072	Basin Electric
		28,340	221,863	7.883	Western
		9	139	16.667	Cogeneration
		56,448	2,397,580	29.303	Subtotal
		77,383	5,960,103	76.204	Total Sales
		N/A	N/A	N/A	Generation and Other
Northern Electric	MN 11	156,535	7,474,203	47.748	United Power Assoc.
		156,535	7,474,203	47.748	Subtotal
		145,688	12,589,047	86.498	Total Sales
		N/A	N/A	N/A	Generation and Other
Northwest Iowa Power	IA 85				
		274,944	14,854,183	53.178	Basin Electric
		281,104	2,038,784	7.381	Western
		6,336	88,881	14.300	Miscellaneous
		556,384	16,681,518	29.483	Subtotal
		637,821	24,038,307	37.678	Total Sales
		71,647	7,346,789	102.835	Generation and Other
Oliver-Mercer Electric	ND 32				
		131,001	7,797,479	59.522	Basin Electric
		16,104	126,047	7.827	Western
		7	187	18.142	Cogeneration
		147,112	7,923,647	53.861	Subtotal
		143,317	10,104,698	70.508	Total Sales
		N/A	N/A	N/A	Generation and Other
Renville-Sibley CPA	MN 75	52,820	2,069,123	39.160	East River Electric Power
		52,820	2,069,123	39.160	Subtotal
		50,297	3,176,802	63.161	Total Sales
		N/A	N/A	N/A	Generation and Other
Rosebud Electric	SD 26				
		17,353	985,358	56.843	Basin Electric
		56,527	465,972	8.243	Western
		73,876	1,451,330	19.640	Subtotal
		68,036	3,031,686	44.563	Total Sales
		N/A	N/A	N/A	Generation and Other

Executive Office of the Chairman
WHITE MOUNTAIN APACHE TRIBE

RONNIE LUPE
CHAIRMAN

STATEMENT

OF

CHAIRMAN RONNIE LUPE

WHITE MOUNTAIN APACHE TRIBE,

FORT APACHE INDIAN RESERVATION, ARIZONA

TO THE SUB-COMMITTEE ON OVERSIGHT AND INVESTIGATIONS

OF THE HOUSE NATURAL RESOURCES COMMITTEE

RESPECTING

THE WESTERN AREA POWER ADMINISTRATION'S [WAPA]

DRAFT ENVIRONMENTAL IMPACT STATEMENT AND RELATED ISSUES

Ronnie Lupe, Chairman
White Mountain Apache Tribe
P.O. Box 1150
Whiteriver, Arizona 85941

PHONE (602) 338-1560 P.O. BOX 1150 WHITERIVER, ARIZONA 85941

Executive Office of the Chairman
WHITE MOUNTAIN APACHE TRIBE

RONNIE LUPE
CHAIRMAN

CHAIRMAN RONNIE LUPE'S STATEMENT
TO
CONGRESSMAN GEORGE MILLER, CHAIRMAN
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS
HOUSE COMMITTEE ON NATURAL RESOURCES

As Chairman of the White Mountain Apache Tribe, I am requesting the assistance of this Committee to render it possible for the White Mountain Apache Tribe to obtain an allocation of federal hydroelectric power from the Western Area Power Administration [WAPA]. This is not a request for charity. Rather, it is a request premised upon the fact that the Tribe has been denied an allocation of federal hydroelectric power by WAPA on the false premise that the Tribe was not a utility. Moreover, the Salt River water which arises on the Tribe's Reservation has been committed by the United States, Tribe's Trustee, to the Salt River Project, which has used the water to generate electricity to benefit the Project. Compounding that discrimination by the United States Trustee against my Tribe is the fact that WAPA has awarded an allocation of federal hydroelectric power to the Salt River Project, so greatly subsidized by the Trustee, in constructing Roosevelt Dam and the hydroelectric power complex.

It is my Tribe's position that the Committee should recognize that the White Mountain Apache Tribe has been vastly discriminated against for the benefit of the Salt River Project. I believe it is wholly proper and fitting that my Tribe be assisted by this Committee to obtain from WAPA a substantial allocation of low cost federal hydroelectric power. With that power, my Tribe can build a firm economy and hopefully end the all-persuasive poverty and unemployment that is found on our Reservation.

Your assistance in this matter will be greatly appreciated. In my accompanying statement there is reviewed and documented the discriminatory practices by Agents of the Trustee United States. They have failed to assist the Tribe in using the Salt River water, to which it is legally entitled, and have delivered that water to the Salt River Project where it is used to generate electrical power for the Project. WAPA has, moreover, simultaneously allocated to that Project, as stated above, federal hydroelectric power while denying it to my Tribe.

Ronnie Lupe

Chairman Ronnie Lupe, Chairman
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INTRODUCTION

Economic Strangulation of Tribe by Agents of the United States Trustee

A continuing economic crisis confronts the White Mountain Apache Tribe, Fort Apache Indian Reservation, Arizona. That crisis was precipitated by the policies to which there is adherence by the Western Area Power Administration, WAPA. Compounding the crisis with which the Tribe is confronted by WAPA's policy is the fact that agency is today formulating plans to allocate "federal hydroelectric power" exclusively for WAPA's current customers. In simplest terms, the White Mountain Tribe, that has been historically excluded from participating in the low costs federal hydroelectric power will continue to be prohibited from obtaining the benefit of that low cost power.

Recently, the White Mountain Apache Tribe sought to obtain from WAPA an allocation of federal hydroelectric power which was to be provided on a short term basis. Irrespective of the then availability of the power and the Tribe's imperative need for low cost power, WAPA denied the Tribe any opportunity to participate in the available supply of that power due to the fact that the Tribe was not a "utility." A short summary of that denial of the Tribe's request is set forth in the June 16, 1994 testimony of the Oglala Sioux Tribe, which appeared with its representatives at that hearing conducted by the House Sub-committee on Oversight and Investigations. That succinct statement is hereafter quoted:

> The requirement of utility status is so prevalent in the thinking of Western [WAPA] and its existing customers that instances can be cited to where the existing consumer utilities have refused to wheel [transport] federal power to the Tribe (assuming they could receive a Western [WAPA] allocation) on the basis that the Tribes are not utilities. The White Mountain Apache Tribe in Arizona, where electrical costs are among the highest in the nation, can cite this experience. Not only does Western deny the tribes an allocation of power on the basis that Tribes do not qualify as utilities, the existing customer utilities of Western refuse to wheel [transport] power to the tribes unless they have utility status.[1]

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[1] Testimony, Wilbur Between Lodges, President Oglala Sioux Tribe, June 16, 1994 hearing, p. 5, 3rd full paragraph.

In a subsequent phase of this consideration, there will be reviewed and documented the specious, indeed, contrived policy adopted by WAPA, as a predicate for denying federal hydroelectric power to the Indian tribes. WAPA's course of conduct is unconscionable. It exists without a scintilla of legal authority. To deny the Tribe its right to federal power on the basis of the fact that the Tribe is not a utility partakes of racial discrimination, all as will be emphasized with legal authorities in support. There is fully reviewed the principles of law which demonstrate that the policy to which reference is made by WAPA is contrary to both legal precedent and the fiduciary obligations of the United States Trustee.

Let it be stressed that, irrespective of the exorbitant costs for power, the Tribe, of necessity, meets all municipal requirements, domestic requirements, and pays outrageous costs for power in the operation of its Fort Apache Timber Company, its Sun Rise Ski Resort, its Canyon Day Irrigation Project and, indeed, all of the numerous activities on the Fort Apache Indian Reservation. In addition, there is subsequently reviewed the unconscionable fact that the United States Trustee, early in the twentieth century, in clear violation of its fiduciary obligations, committed all of the Salt River water which arises on Tribe's Reservation for the purpose of generating electricity and providing irrigation water for the non-Indian Salt River Federal Reclamation Project. As will be reviewed, the Salt River Project has been allocated by WAPA a substantial block of the federal hydroelectric power in addition to the vast generating facilities provided to the Salt River Project by the Secretary of the Interior. Antecedent to the review of controlling principles of law, reference will be made to the issues raised by Chairman George Miller of the Subcommittee on Oversight and Investigations House Committee on Natural Resources respecting the policies of the Western Area Power Administration (WAPA).

Chairman Miller Is Petitioned to Preclude Perpetuation
of the Power Monopoly by Current Users

These issues confronting the White Mountain Apache Tribe in regard to obtaining low cost federal hydroelectric power at Tribe's Reservation are well stated and reviewed in the Chairman's letter dated May 25, 1994, to the Secretary of the Department of Energy, Hazel

O'Leary. There is attached to this statement a copy of Chairman Miller's May 25, 1994 letter, in which he invited Secretary O'Leary or her designate to appear at the June 16, 1994 hearing. Accompanying that letter is a document submitted by Chairman Miller to the Department of Energy, entitled "Department of Energy Questions, June 16, 1994, Hearing on WAPA Power Allocation."

It will be observed from the May 25, 1994 letter, that Chairman Miller was seeking to obtain testimony respecting proposed policies that would result in the allocation of federal hydroelectric power for as long as the next forty years. Chairman Miller, in his letter, likewise alluded to the proposals which are set forth in WAPA's "Draft Environmental Impact Statement," which contemplated the renewal of contracts to provide federal hydroelectric power for "...as long as 35 years and that current customers receive between 90 and 100 percent of the available power resource."

Chairman Miller, in his "Questions," challenged the wisdom of perpetuating the monopoly by current consumers of the federal hydroelectric power and presented among others this question:

> 6. The DEIS [Draft Environmental Impact Statement] only considers power allocation options that involve reserving between 90 and 100 percent of the available power resource for WAPA consumers. The DEIS does not analyze the environmental effects of any alternative power allocation regimes, including the following:
> * providing power to preference entities that do not currently receive WAPA power such as Indian tribes and others,

The White Mountain Apache Tribe has considered the oral testimony that was given at the June 16, 1994 hearing. It has likewise analyzed in detail the relevant comments made by those entities that have contracted for WAPA power to the exclusion of the White Mountain Apache Tribe. Predicated upon both the oral and documented material, this conclusion is expressed by the Tribe:

> The current holders of WAPA contracts seek to perpetuate the monopoly of federal hydroelectric power dating back to the period when the Bureau of Reclamation and the Corps of Engineers were not only the principal producers of federal hydroelectric power, but were likewise the dispensers of that power. Included in the monopoly of the federal hydroelectric power is the Salt River Project, which was

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> initially vastly subsidized by the Secretary of the Interior, when that official constructed pursuant to the Reclamation law the Salt River Federal Reclamation Project.

In a subsequent phase of this consideration, the White Mountain Apache Tribe reviews and documents the unconscionable violation of its invaluable Salt River rights and the violation of the trust responsibilities of the United States. It is important to stress here that Chairman Miller, at the June 16, 1994 hearing, was an outspoken advocate on behalf of the Native American Tribes. Chairman Miller, moreover, placed squarely in issue the discriminating policy of WAPA denying the Tribe federal hydroelectric power on the basis that Tribes do not qualify as utilities created under local state laws.

TRIBAL SOVEREIGNTY DENIGRATED BY WAPA'S REQUIREMENT THAT TRIBES BECOME STATE UTILITIES TO QUALIFY FOR FEDERAL HYDROELECTRIC POWER

The Tribe perceives it to be most unfortunate that Deputy Secretary White, Department of Energy, reiterated WAPA's requirement that as a condition precedent to the Tribes participating in available federal hydroelectric power that they must become "Native American" utilities. The only means pursuant to which the Tribes could become utilities is by complying with the laws of the states in which the Reservations are located, and simultaneously subjecting themselves to state law. WAPA's illegal requirement strikes at the Tribe's inherent sovereign power dating from time immemorial. Compliance with requirements of that character effectively reduces the Tribe to the status of "...cities, counties, and other organized bodies..." which derive their power from the states,[2] drastically diminishing the sovereign status of the Tribe.

The White Mountain Apache Tribe aggressively rejects the policy of WAPA that the Tribe should diminish its inherent sovereign status as a condition to receiving federal hydroelectric power. Respecting the Tribe's inherent sovereign powers, the Supreme Court in its hallmark decision of *White Mountain Apache Tribe v. Bracker*,[3] declares:

> ...congressional authority and the 'semi-independent position' of Indian tribes have given rise to two independent but related <u>barriers to the</u>

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[2] *See, United States v. Kagama*, 118 U.S. 351, 379-380, (1886).

[3] 448 U.S. 136, 142-145 (1980).

> assertion of state regulatory authority over tribal reservations and members.[4]

These are the barriers to which the Supreme Court had reference:

> First, the exercise of such authority may be pre-empted by federal law... Second, it may unlawfully infringe 'on the right of reservation Indians to make their own laws and be ruled by them...The two barriers are independent because either, standing alone, can be a sufficient basis for holding state law inapplicable to activity undertaken on the reservation or by tribal members.[5]

Continuing to emphasize the nature of the sovereign powers of Native American Tribes, and the White Mountain Apache Tribe itself, the Supreme Court added this statement:

> ...traditional notions of Indian self-government are so deeply engrained in our jurisprudence that they have provided an important 'backdrop,'...against which vague or ambiguous federal enactments must always be measured.[6]

In simplest terms, absent explicit federal legislation, the inherent powers of the Indian tribes will not be diminished. On the subject of diminishment of Tribal sovereignty, the Court in *Bracker* continued rejecting policies which would tend to diminish the sovereign power of the White Mountain Apache Tribe using these terms:

> Ambiguities in federal law have been construed generously in order to comport with these traditional notions of sovereignty and with the federal policy of encouraging tribal independence.[7]

It is abundantly manifest that the Highest Court seeks to strengthen--not diminish--the Tribe's inherent sovereign powers. Under those circumstances it is urged to this Committee that WAPA should no longer demand that the Tribe subject itself to State law and the administration of the states in order to become a utility acceptable to WAPA. It is repeated that the concepts that the Tribe must become a utility have no basis whatever in law, but rather is strictly a policy determination that is in grave error.

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[4] *White Mountain Apache Tribe v. Bracker*, 448 U.S. 136, 142, (1980).
[5] *Ibid.*, pgs. 142-143. (Emphasis supplied). *Williams v. Lee*, 358 U.S. 217, 220, (1959), *See* also *Washington v. Yakima Indian Nation*, 439 U.S. 463, 502 (1979); *Fisher v. District Court*, 424 U.S. 382 (1976); *Kennerly v. District Court of Montana*, 400 U.S. 423 (1971).
[6] *Ibid.*, p. 143.
[7] *Ibid.*, pgs. 143-144.

In *Bracker*, the Supreme Court clearly establishes the criteria that will control in determining whether the White Mountain Apache Tribe should be subjected to the laws of the State of Arizona relative to the creation, control, and management of utilities. This is the language used in that decision:

> When on-reservation conduct involving only Indians is at issue, state law is generally inapplicable, for the State's regulatory interest is likely to be minimal and the federal interest in encouraging tribal self-government is at its strongest.[8]

The Supreme Court reaffirmed the concepts of *White Mountain Apache Tribe v. Bracker*, in the case of *New Mexico v. Mescalero Apache Tribe*.[9] There, the Supreme Court denied the State of New Mexico the power and authority to impose upon the Mescalero Apache Tribe the laws of the State of New Mexico as they pertain to the management of the fish and wildlife resources within the Reservation. The Supreme Court stated:

> The Tribe has engaged in a concerted and sustained undertaking to develop and manage the reservation's wildlife and land resources specifically for the benefit of its members.[10]

Continuing, the Supreme Court emphasized that the independence of the Tribe there involved from state control stems from the fact that:

> The tribal enterprise in this case clearly involves 'value generated on the reservation by activities involving the Trib[e].'[11]

In *Mescalero Apache*, the Supreme Court summarized governing principles that are controlling here. For example, the Highest Court emphasized that:

> The sovereignty retained by the tribes includes 'the power of regulating their internal and social relations,....' A tribe's power to prescribe the conduct of tribal members has never been doubted, and our cases establish that 'absent governing Acts of Congress,' a State may not act in a manner that 'infringe[s] on the right of reservation Indians to make their own laws and be ruled by them.'[12]

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8 *Ibid.*, p. 144.
9 462 U.S. 324, 341 (1983).
10 462 U.S. 324, 341, (1983).
11 *Ibid.*
12 *Ibid.*, p. 332.

Bracker and *Mescalero Apache* underscore the shocking impropriety of WAPA denying the White Mountain Apache Tribe the right to participate in an allocation of federal hydroelectric power absent submitting to the jurisdiction and control of State laws regulating the creation and operation of utilities which are empowered to distribute electricity to its customers. It is too clear for question that the White Mountain Apache Tribe has inherent sovereign power to perform all those services without any consideration of state law or the interference of state administration.

The Supreme Court in its *Crow* Tribe Decision[13] further strengthens the assertions of the White Mountain Apache Tribe that it is fully empowered to perform all of the services and to enter into all of the contracts that would be involved in obtaining a supply of federal hydroelectric power from WAPA. The *Crow* Tribe Decision alluded to the fact that the Native American Tribes had retained "...some of the inherent powers of the self-governing political communities that were formed long before Europeans first settled in North America." Involved there is whether the Tribes had retained "...the power to resolve disputes..." in tribal courts between Indians and non-Indians as "...an attribute of inherent tribal sovereignty...."[14] That critical issue, said the Highest Court, should first be considered "...in the Tribal Court itself. Our cases have often recognized that Congress is committed to a policy of supporting tribal self-government and self-determination."[15]

In its *Crow* Decision, the Supreme Court demonstrated the dignity that it has accorded to the Tribe's sovereign status using this language:

> Exhaustion of tribal court remedies, moreover, will encourage tribal courts to explain to the parties the precise basis for accepting jurisdiction, and will also provide other courts with the benefit of their expertise in such matters in the event of further judicial review.[16]

To strengthen Tribal self-government, the Supreme Court emphasized these principles:

> We have repeatedly recognized the Federal Government's long-standing policy of encouraging tribal self-government...This policy reflects the fact

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[13] *National Farmers Union Insurance Co. v. Crow Tribe of Indians, et al.*, 471 U.S. 845, 851 (1985).
[14] *Ibid.*, at 852.
[15] *Ibid.*, p. 856.
[16] *Ibid.*, p. 857.

> that Indian tribes retain 'attributes of sovereignty over both their members and their territory,'....[17]

As Chairman of the White Mountain Apache Tribe, I petition Chairman George Miller to support my Tribe and other Tribes in their resistance to WAPA's mandate that the Tribes must submit to the state laws respecting utilities as a condition to participating in the allocation of federal hydroelectric power. It is too clear for controversy that the Tribes have retained their inherent sovereign power fully to contract with WAPA for an allocation of the power in question. Moreover, they have vested authority by reason of their sovereignty to perform all acts essential properly to manage, control, and to distribute within their Reservation the electrical energy so vital to their economic development and social stability.

TRUSTEE'S ATTEMPTED ILLEGAL SEIZURE OF TRIBE'S RESERVED SALT RIVER RIGHTS INSEPARABLE FROM TRUSTEE'S DISCRIMINATORY PRACTICES IN DENYING TRIBE AN ALLOCATION OF FEDERAL HYDROELECTRIC POWER

Chairman Miller's Question No. 6 quoted above as to why WAPA does not consider an allocation of federal hydroelectric power to Indian Tribes is most relevant. That inquiry should be considered indepth by the committee.[18] Chairman Miller has raised one of the most critical inquiries in light of the "fiduciary relationship" between the Native American Tribes and the United States Trustee. In these succinct terms, the Supreme Court in the case of *United States v. Mitchell* makes this most relevant, indeed controlling, declaration as it pertains to the Chairman's question:

> This Court has previously emphasized 'the distinctive obligation of trust incumbent upon the Government in its dealings with these dependent and sometimes exploited people.'[19]

Continuing, the Supreme Court declared "this principle has long dominated the Government's dealings with the Indians."[20] The Tribe, based on Chairman Miller's Question No. 6, inquires as

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[17] *Iowa Mutual Insurance Co v. LaPlante et al.*, 480 U.S. 9, 14 (1987).
[18] *See* attached Chairman Miller's May 25, 1994 letter with Questions.
[19] 463 U.S. 206, 225 (1983).
[20] *Ibid.*, citing *Seminole Nation v. United States*, 316 U.S. 286, 296 (1942); *United States v. Mason*, 412, 391, 398 (1973); *Minnesota v. United States*, 305 U.S. 382, 386 (1939); *United States v. Shoshone Tribe*, 304 U.S. 111, 117-118 (1938).

to why, when there is a "fiduciary relationship" between the Tribes and the United States does WAPA, an agency of the United States, deny the Tribes the imperatively required low-cost power which can and should be allocated to the Tribes. Throughout the remainder of this consideration, the "fiduciary relationship" between the Tribes and the United States Trustee, as it pertains to the allocation of federal hydroelectric power, will be the dominant factor.

The Tribes' inquiries include not only the violation of the "fiduciary relationship" between the Trustee and the Tribes, but likewise the serious questions as to whether WAPA is acting in a discriminatory fashion against the Tribes in refusing to allocate to the Tribes a share of the federal hydroelectric power. Moreover, the monopoly exercised by the politically powerful entities that control disposition of federal hydroelectric power are identically the same entities that monopolize the rights to the use of water throughout the arid and semi-arid west. The destructive consequences of those two monopolies upon the Native American Tribes can best be comprehended when consideration is given to the all-pervasive poverty and unemployment on Indian Reservations.

An integral part of this consideration pertains to the Native American Tribe's invaluable reserved rights to the use of water which vastly contribute to the generation of federal hydroelectric power. Reference in that connection is made to the *Winters* Doctrine in which the Supreme Court of the United States, in explicit terms, declared the nature, extent, validity, and paramount character of the Native American Tribes' reserved rights to the use of water in the Western streams.[21]

It is most relevant here in regard to the White Mountain Apache Tribe that the Court of Federal Claims concluded as a matter of law that the "trust relationship" between the United States and the Tribe commenced when the Tribe entered upon the White Mountain Apache Indian Reservation pursuant to the November 9, 1871 Executive Order.[22] Predicated upon that

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[21] *Winters v. United States*, 207 U.S. 564 (1908).
[22] *White Mountain Apache Tribe v. United States*, 11 Cl.Ct. 614, 621, (1987).

Court's decision that the "fiduciary relationship" existed between the Tribe and the United States, it concluded as a matter of law that the White Mountain Apache Tribe's "...*Winters* Doctrine rights...take their life from the date, at the latest, when the reservation was created..." which, as stated, is 1871.[23]

In reviewing the controversy between the White Mountain Apache Tribe and the Salt River Project, it is an undeniable fact that the Project is now and has been the prime beneficiary of all of the Salt River water which arises on the Tribe's Fort Apache Indian Reservation. It is likewise the fact that WAPA has allocated to the Salt River Project a substantial share of the federal hydroelectric power administered by WAPA.

The Court of Federal Claims declared and adjudged against the United States Trustee that, the White Mountain Apache Tribe's "...*Winters* Doctrine rights...have priority over the rights asserted by the later-created SRVWUA [Salt River Project]."[24] Those reserved *Winters* Doctrine rights to the use of water retained by the White Mountain Apache Tribe – not transferred to the United States Trustee – are adequate to meet the Tribe's present and future water requirements for all beneficial uses.[25]

Rationale of the Supreme Court, when it enunciated the *Winters* Doctrine, is most relevant in this consideration. It is stated by the Supreme Court that in the arid and semi-arid regions of the United States, in which the Tribe's Fort Apache Indian Reservation is located, an adequate and permanent supply of water is an imperative necessity if the Tribe is to have a sound economic base both now and in the future. It is most relevant that the Supreme Court was explicit in declaring that the United States Trustee was obligated to provide an adequate supply of water to meet the Tribe's needs. Continuing, the Court stated that without water the reservation lands were "practicably valueless." As will be emphasized, the Secretary of the Interior, the principal agent of the United States Trustee, rather than fulfilling the obligations of

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23 *Ibid.*, p. 638.

24 *Ibid.*, p. 638.

25 *White Mountain Apache Tribe v. United States*, 11 Cl.Ct. 614, 638 (1987) citing *Winters v. United States*, 207 U.S. 564 (1908); *Conrad Investment Co. v. United States*, 161 F.829 (CA 9, 1908); *Arizona v. California*, 373 U.S. 546 (1963).

the Trustee on behalf of the Tribe, monopolized all of the Salt River water for the benefit of the Salt River Project. In the process, the Secretary of the Interior suppressed all possibility of the Tribe undertaking a program to develop hydroelectric plants on the upper reaches of the Salt River within the Tribe's Reservation. Continuing, the Supreme Court in *Winters* emphasized that, absent an adequate and reliable water supply, the agreement between the Tribe there involved and the United States Trustee creating the reservation would be defeated. Precisely the same principles are applicable to the White Mountain Apache Tribe and its Reservation.

It is most relevant here that the Tribe's reserved *Winters* Doctrine Salt River rights to the use of water are interests in real property of the highest dignity, and are fully protected by the due process provisions of the Constitution of the United States.[26]

In the paragraphs which follow, there will be reviewed the intentional violation of the trust obligation owing by the United States to the White Mountain Apache Tribe. Positive proof will be offered to establish that the United States Trustee, rather than fulfilling its fiduciary obligations to preserve, protect, and utilize Tribe's property solely for the benefit of the Tribe, has violated those principles of law. The single most controlling principle of trust law is this:

> <u>The Trustee is under a duty to the beneficiary to administer the trust solely in the interest of the beneficiary</u>.[27]

It is to be observed that the United States Trustee, for its own benefit and for the benefit of the Salt River Project, constructed the dam and reservoir pursuant to which the Salt River Project generates vast quantities of hydroelectric power while the White Mountain Apache Tribe is economically depressed due to the lack of low cost power to service its business enterprises.

<u>"The Salt River Project" Monopolizes The Salt River Water</u>

There is reviewed below the fact that the Secretary of the Interior, while refusing to aid the Tribe in the utilization of the Salt River water on the Tribe's Fort Apache Indian Reservation, nevertheless, as reviewed above, committed that water to the benefit of the Salt River Project

[26] *Ashwander v. T.V.A*, 297 U.S. 288, 330 (1936); *United States v. Chandler-Dunbar*, 229 U.S. 5473 (1913); Gila River, *Pima Maricopa Community v. United States*, 684 F.2d 852, 863 Cl.Ct. (1982).
[27] Vol. 1, Restatement of the Law, Trust 2nd, Sec. 170, Duty of Loyalty.

and subsidized the use of that water by the Project. Plate 1 of this consideration, which follows, graphically displays (1) the source of the Salt River, most of the flow of which arises within the Tribe's Fort Apache Indian Reservation; and (2) that the entire flow of the Salt River enters

WHITE MOUNTAIN APACHE TRIBE OF ARIZONA v. U.S.
Cite as 11 Cl.Ct. 614 (1987)

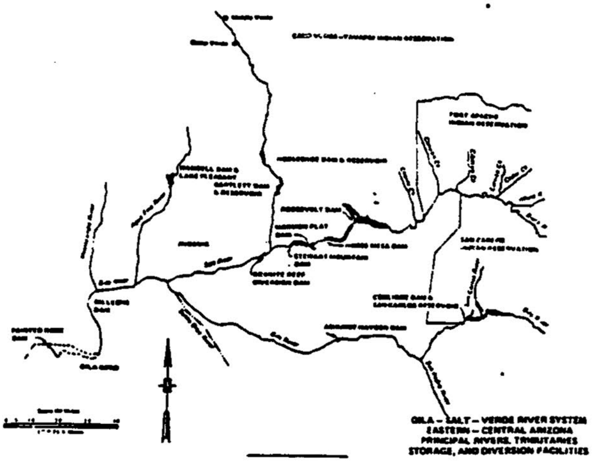

PLATE I

Roosevelt Reservoir created by the dam, constructed and largely subsidized by the United States Trustee for the benefit of the "Salt River Project," not the White Mountain Apache Tribe, which is the beneficiary of the trust.

The Court of Federal Claims reviewed the critical facts graphically displayed on Plate I stating that:

> Downstream of the [Tribe's] reservation on the Salt River are the Roosevelt Dam and Reservoir; Horse Mesa Dam and Apache Lake; Mormon Flat Dam and Canyon Lake; and Stewart Mountain Dam and Saquaro Lake. [28]

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[28] *White Mountain Apache Tribe v. United States*, 11 Cl.Ct. 614, 623 (1987). (Emphasis supplied)

The Court of Federal Claims continued to describe in detail the magnitude of the commitment by the United States Trustee of the Salt River waters, to which the Tribe is legally entitled, and described in detail the vast expenditure of federal funds to build generating capacity for the Salt River Project. On the subject the court stated:

> These structures were constructed from 1905 to 1930 as the Salt River Federal Reclamation Project and utilized all of the natural and surplus flow of the Salt River coming off of the reservation that has not been appropriated and used upstream.[29]

The explicit findings of the court established beyond challenge that the United States Trustee, acting for the benefit of the Trustee's own Salt River Federal Reclamation Project, attempted illegally to commit all of the Salt River water to the Salt River Project to which the Tribe is legally entitled.

Those conclusions are fully supported by the following findings of the court:

> ...the study of water storage potential undertaken by Arthur Powell Davis of the United States Geological Survey, in 1903, before construction began on the Roosevelt Dam, postulated that no upstream diversions [on the Tribe's Reservation] would diminish the flow into the Reservoir.[30]

Reference is again warranted to Plate I, set forth above, establishing the degree of total commitment by the Tribe's Trustee of all of the waters of the Salt River to the non-Indian Salt River Project in disregard of the Tribe's basic *Winters* Doctrine Rights, and the unconscionable violation of the Trustee's obligation owing to the White Mountain Apache Tribe.

In underscoring the fact that title to the reserved *Winters* Doctrine Salt River rights resides in the White Mountain Apache Tribe, the Court of Federal Claims concluded as a matter of law and entered its judgment declaring that:

> [the Tribe's title to reserved rights based on] 'the *Winters* Doctrine was not preempted by the facts that downstream users had claimed all of the

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[29] *White Mountain Apache Tribe v. United States*, 11 Cl.Ct. 614, 623 (1987). (Emphasis supplied)
[30] *Ibid.*, p. 629. (Emphasis supplied)

> natural flow, or that the dam was designed [by the Trustee United States] to take all of the flow the Salt River could give it.'[31]

This Committee is requested carefully to review the shocking injustice that the White Mountain Apache Tribe is experiencing today. As graphically displayed, a gigantic hydroelectric empire was constructed and delivered by the United States Trustee to the Salt River Project. That same project is today receiving an additional bonanza of federal hydroelectric power by the allocations of the Western Area Power Administration, which agency of the Trustee is today denying the Tribe any federal hydroelectric power by reason of the sham that the Tribe is not a state created utility, all as reviewed in detail above.

<u>WAPA Intends to Perpetuate the Monopoly of Current Users of Federal Hydroelectric Power to Exclude the White Mountain Apache Tribe</u>

It was manifest at the June 16, 1994 hearing before the Subcommittee on Oversight and Investigations of the House Natural Resources Committee that the politically powerful beneficiaries of WAPA's allocation of federal hydroelectric power had no intention of releasing their share of the power allocated to them by WAPA. CREDA, the Colorado River Energy Distributors Association, broadly displayed its strong opposition to relinquishment of any of the power that WAPA has allocated to its members. It was of intense interest to the White Mountain Apache Tribe, that has been consistently denied any federal hydroelectric power, to read this statement by CREDA, of which the Salt River Project is a member:

> CREDA members were involved in demand side management and energy efficiency programs prior to enactment of the Energy Policy Act....For example, DSM initiatives begun in 1986 have saved the Salt River Project (SRP) in Arizona about 70 MW of capacity. Salt River Project plans to reduce peak demand for the next 20 years by another 540 MW through additional DSM programs.[32]

It is respectfully urged to this Committee that CREDA, predicated upon the plans of the Salt River Project to reduce peak demands, could very well, as part of its program, share with

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31 *Ibid.*, p. 629.

32 CREDA, Testimony of Clifford Barrett, Executive Director, Colorado River Energy Distributors Association, p. 1, final paragraph.

the White Mountain Apache Tribe a substantial block of federal hydroelectric power that has been allocated to it. The Salt River Project, as reviewed above, has been vastly subsidized and has been accorded preferential treatment by the United States by providing Salt River water utilized in the generation of hydroelectric power in the vast Roosevelt Dam power generating complex.

It is only fair, equitable, and sound planning for the members of CREDA and WAPA willingly to permit the White Mountain Apache Tribe, which has been discriminated against for so long, to have allocated to it a substantial block of the low cost federal hydroelectric power delivered to Tribe's Fort Apache Indian Reservation.

Respectfully submitted,

Dated: July 7, 1994

Ronnie Lupe

Ronnie Lupe, Chairman
White Mountain Apache Tribe
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Whiteriver, Arizona 85941

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June 28, 1994

Honorable George Miller
House Natural Resources Committee
1324 Longworth HOB
Washington, DC 20515

Dear Mr. Chairman:

The Blackfeet Indian Reservation is at the headwaters of the Missouri River. Our Reservation is bounded on the west by Glacier National Park, lands that were taken from us on the prospect that gold might be discovered as it was in the Black hills, and on the north by Canada.

The Blackfeet Tribe supports the statement of Wilbur Between Lodges, Chairman of the Oglala Sioux Tribe. His written statement was presented on behalf of the Oglalas and other Missouri River Basin tribes in your June 16, 1994, oversight hearing on the allocation of power by the Western Area Power Administration. The history of encroachments upon the Blackfeet water rights on the St. Mary and Milk rivers is presented with reasonable accuracy in Mr. Between Lodges' statement. It is likewise correct that the State of Montana has an ongoing McCarran Amendment adjudication involving reserved water rights of the Blackfeet Tribe and that, absent negotiation to settle the lawsuit, there is no other forum or alternative available to the Blackfeet.

There is a strong need for an allocation of Western power resources on the Blackfeet Indian Reservation. Our cost of power from Glacier Electric averages 25 mills per kilowatt hour, (1992). Western power is sold at a firm wholesale rate of 14 mills per kilowatt hour. Climactic conditions are extreme during our winters, sufficiently severe to support glaciers that drift ever so slowly from our mountains in the west.

According to the 1990 Census, the Blackfeet Indian population had a per capita income of $4,718.00 annually, compared with Montana per capita income of $11,213.00 annually. Changes in federal policy that would allocate federal low-cost energy in greater proportion than presently available through Glacier Electric would bring a measure of relief to my people. Changes in federal policy to allow us to exercise our Missouri River

Honorable George Miller, Chairman
June 28, 1994
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tributary water rights via the mechanical equipment of the Pick-Sloan project would assist the Blackfeet and other tribes immeasurably.

I submit this correspondence to become part the Hearing record. Thank you for your foresight in this matter.

Sincerely,

Earl Old Person, Chairman
Blackfeet Indian Nation

Oglala Lakota Nation
Box H
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(605) 867-5821

Wilbur Between Lodges

Mel V. Lone Hill

Theresa B. Two Bulls

Crystal R. Eagle Elk

Philip Under Baggage

June 29, 1994

Honorable George Miller, Chairman
House Natural Resources Committee
1324 Longworth HOB
Washington, D.C. 20515

Dear Mr. Chairman:

The Oglala Sioux Tribe wishes to clarify the record of the June 16, 1994 oversight hearing regarding your inquiry on the need for legislation to address Western's requirement for *utility* status as a pre-requisite for marketing Western's power. Likewise, we seek to address a remark by Mr. Driver concerning his opinion of the amount of power to be withdrawn from existing customers to meet Indian and enviromental needs.

On the first matter, *utility* status is presently an administrative requirement of the Department of Energy, not a Congressional or Statutory mandate. My written statement petitions the Committee to consider legislation (that we would be willing to draft) because Western requires that Indian tribes have *utility* status as a condition of a power allocation. I cited the following as representative of Western's policy in this matter.

....The primary consideration of 'utility' status is that an entity must control and operate its own distribution system. Since Western has not taken action on the proposed allocation criteria, and the interim Navajo Surplus will be sold under the provisions of Section III, B, 3 of the Interim Plan, this factor will only be considered if a conflict arises over contracting with a utility or a non-utility. ***Western will first contract with the entity considered to have 'utility' status...***

I also cited the following as the representative view of the federal courts in reviewing Western decisions on allocation of Western energy.

The preference clause requires only that public entities be given a preference over private entities in the marketing of power generated by federal

Honorable George Miller, Chairman
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reclamation projects...It does not require that all preference customers receive an allotment...Where, as here, one preference entity challenges the Secretary's decision to discriminate against it in favor of other preference entities, the reclamation laws provide no law to apply to the dispute. If he so chooses, the Secretary can market all available...power to a single entity without running a fowl of the preference clause.

In light of the Energy Department's apparent willingness to change its policy, we would have increased faith in measures short of legislation. Specifically, a firm letter from the Committee to Department of Energy expressing the desire of the legislative branch for Western to allocate power directly to Indian tribes without a requirement for *utility* status would strengthen our capability to participate in Western power.

Part of the Missouri River Basin tribes' request for allocation of power is based on residential, industrial, agricultural and institutional needs and part is based on a need for equity in the treatment of our *Winters* doctrine water rights: equity that is absent in the McCarren Amendments atmosphere of litigation and negotiation. Any negotiation with a state starts from a position of weakness forced on the tribes by decades of encroachment. Legislation will clearly be required with rationale similar to the lower Colorado River Basin Development Fund (43 USC 1324) or for some other mechanism that permits the tribes to exercise their *Winters* doctrine water rights in the matter that brings dignity to, rather than drains dignity from, the Indian people.

I am informed that Mr. Bruce Driver of land and Water Fund of the Rockeies responded to one of your inquiries during the June 16, 1994 hearing to the effect that he had concluded that 80% of Western's power marketing to existing customers would leave sufficient capability to withdraw or reserve power to meet both enviromental and Indian needs. Our representative met briefly with Mr. Driver following the hearing and determined that Mr. Driver had not researched the Indian needs and had inadvertently combined Indian power needs (unsearched by the enviromental groups he represents) with needs to withdraw power from existing customers to maintain or enhance the environment. We trust that Mr. Driver will confirm that he did not intend to include Indian needs in his response to your inquiry.

Your inclusion of this letter in the hearing record will be greatly appreciated. On behalf of the Oglala Sioux and other Missouri Basin tribes, I express my genuine gratitude for the steps taken by you and your Committee to bring a more sensible and equitable policy to the allocation of Western power.

Honorable George Miller, Chairman
June 29, 1994
Page Three

Sincerely yours,

for - Wilbur Between Lodges, President
Oglala Sioux Tribe

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PLEASE REPLY TO THE
WASHINGTON, D.C. OFFICE

June 30, 1994

Honorable George Miller, Chairman
House Committee on Natural Resources
Subcommittee on Oversight and Investigations
1324 Longworth House Office Building
Washington, D.C. 20515-6201

Re: Supplementary Oglala Sioux materials for the record of the June 16, 1994 Hearing on Western Area Power Administration Proposals to Determine the Allocation of 7,000 Megawatts of Federal Hydroelectric Power

Dear Chairman Miller:

On June 16, 1994, the Oglala Sioux Tribe was privileged to present testimony before your subcommittee on behalf of the Mni Sose Inter-Tribal Water Rights Coalition of the Missouri River Basin. Our firm is special counsel to the Tribe on water and power issues. At the direction of the Tribe, we are submitting material to supplement the record of the June 16 hearing with information relating particularly to the Oglala Sioux Tribe. We appreciate the opportunity to do so.

This information deals with the electric supply system serving the Oglala's own Pine Ridge Reservation, addresses some of the legal implications of utility requirements contracts, perhaps necessitating the need for federal legislation, addresses legal and political issues surrounding obtaining a WAPA allocation and emphasizes basic reasons supporting such an allocation for the Oglala Sioux Tribe.

We are grateful for your leadership on this critical issue. For so long the Tribe has sought equity in its dealings with WAPA, both in terms of the decisions to be made for the year 2000 and those being made even now. The Tribe sought your intervention only after all its efforts failed and a fair policy from the Department of Energy seemed impossible.

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I. The Electric Supply System Serving the Pine Ridge Reservation in South Dakota

The direct supplier of most of the electricity to the Pine Ridge Reservation is the Lacreek Electric Association which also serves areas beyond the Reservation. In addition, the extreme southwestern part of the Reservation is served by the Nebraska Public Power System.

Lacreek is a "rural electric cooperative," a non-profit utility owned by its customers. In return for membership, the members agree to buy all the power they need from the cooperative. The customers theoretically control the cooperatives by electing the governing board in annual elections. However, all tribal efforts to become involved politically in the cooperative to affect its policy and administration have failed miserably. The cooperatives (hereinafter occasionally referred to as co-ops or RECs) are organized under a South Dakota law governing electric co-ops specifically. S.D.C. Chap. 47-21.

Lacreek does not have any electric generating equipment of its own. It purchases all of the electricity its customers need from another utility. What Lacreek owns are the distribution power lines and equipment that link customers to the high voltage substations and transmission lines owned by the generating utilities which indirectly supply them.

Lacreek obtains its electric power from a larger "generation and transmission" (G&T) cooperative of which it is an owner/member. That supplying G&T utility is the Rushmore Electric Power Cooperative operating out of Rapid City, South Dakota. It serves seven cooperatives. Lacreek has signed "full requirements" contracts with Rushmore, promising to purchase all of the electricity it needs from Rushmore. The contracts last until 2020.

Rushmore has generating capability of its own from its member co-ops and owns other generating equipment that it leases, however, to Black Hills Electric Company. But by far the bulk of the power it transmits to its members comes from two other sources. One is the very inexpensive electricity from the federal hydroelectric facilities on the Missouri River which is marketed by the Western Area Power Administration (WAPA) operating out of Billings, Montana to various regional utilities including Rushmore.

The other source of supply Rushmore draws upon to serve the local RECs' needs is a third electric cooperative, Basin Electric Power Cooperative operating out of Bismark, North Dakota. Basin is the largest producing electric cooperative in the United States. It serves rural electric cooperative loads in eight states on the northern plains. It has major coal-and lignite-fired generating facilities that are used to supplement the electric supply provided by the federal hydroelectric facilities, but at a much higher price. Basin sells its power at about five times the rate at which WAPA sells its power.

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Rushmore's contract with Basin obligates it to purchase all its requirements from Basin except for that it obtains from WAPA and other generating sources of its own. The Tribe's calculations indicate that 13.5 percent of Rushmore's energy needs are met with WAPA power and the remaining 86.5 percent comes from Basin. The contract expires in 2020.

Thus, the basic structure of supply is one of utilities of increasing geographic size: Lacreek serves the local area; Rushmore serves the local REC and six others in South Dakota; Basin and WAPA serve Rushmore and most other cooperatives throughout an eight state region. Because of its low prices, WAPA is the preferred source of supply.

South Dakota is a part of the Mid-Continent Area Power Pool that encompasses an area stretching from western Wisconsin to eastern Montana and from Manitoba-Saskatchewan to Iowa and Nebraska. This area is interlinked by various utilities' transmission lines. These linkages help protect reliable electric service in the case of the failure of a generating unit or transmission line. They also facilitate the transfer of electricity from areas of surplus to areas of deficit and from low cost areas to higher cost areas.

II. Legal Implications Of The "Requirements Contracts"

As mentioned previously, some of the utilities involved in serving the Reservation are related by way of requirements contracts. Lacreek has agreed to buy all the electricity it needs from Rushmore. The basic legal rule is that under a requirements contract the purchaser is required to conduct its business in good faith and may not use some subterfuge to violate its obligations to buy. That does not mean that the buyer has to operate its business to maintain some particular level of requirements. In fact, if a requirements customer goes out of business, its requirements drop to zero. If it buys nothing, thereafter, it has not breached the contract. See generally, 1 Williston Contracts § 104A (3rd Ed. 1957); 67 M. Jur. 2d § 288, § 289; see Empire Gas Corporation v. American Bakeries Company, 840 F.2d 1333 (7th Cir. 1988) (Posner, J.)

Courts have used the obligation of good faith to stop requirements customers from simply renaming their corporation, or selling or leasing it in such a manner that they retain control, as a means of eliminating the original company's requirements. See Western Oil and Fuel Company v. Kemp, 245 F.2d 633 (8th Cir. 1957). In at least two instances, courts have foreclosed the efforts of distribution co-ops (like Lacreek) to break their requirements contracts to G&T co-op in order to reduce their retail rates. In Tri-City Generation and Transmission Association v. Shoshone River Power, Inc., 874 F.2d 1346 (10th Cir. 1989), a distribution co-op sold all of its assets to a private utility which would then serve the co-op members' loads. The court noted that in the special world of electric cooperatives, a requirements contract is not really "a routine arms-length . . . contract between unrelated, private for profit parties." Rather, the requirements contract established the essential relationship between the parties and was instrumental in permitting the G&T to obtain REA loans. The court held that a primary purpose of the contract was to serve the members of the distributing co-op members (also, the co-op owners) as long as they needed power. The mere sale of the utility did not change the members' (owners') needs. The court decided that the co-op had breached the requirements contract by selling itself to another utility and assessed damages in favor of the G&T.

The Tri-City court, among other things, relied upon the case of Texas Industries, Inc. v. Brown, 218 F.2d 510 (5th Cir. 1965). There the court found breach of a requirements contract when the buyer simply leased its plant to a third party. The court there decided that the obligations of the plant were to subject of the requirements contract, not the particular owner or operator. It said the buyer could not avoid responsibility by leasing the plant to someone else to operate; the party assuming the lease also assumed the requirements obligations of the lessor. Cf. United States v. Southwestern Electric Coop. Inc., 869 F.2d 310 (7th Cir. 1989) (refusing to excuse a distribution co-op from its requirements contract with a G&T simply because rates have skyrocketed).

Even if a breach of a requirements contract is shown, that does not necessarily mean that a court will require the purchaser to continue buying power. Such a remedy, known in the law as "specific performance," is rare. Courts usually do not demand that a party actually perform a contract. Instead, they assess damage against the breaching party. Thus, a distribution co-op that stopped buying power on a requirements contract might have to pay the G&T the difference between the price that G&T could get from selling its power elsewhere and the price it would have obtained from the cooperative. If there were a strong energy market with much demand for electricity, then a cooperative could breach an agreement and perhaps pay no damages at all. If the circumstances are those that prevail in the Upper Plains now, however, where there is a substantial energy surplus, it is unlikely that a G&T could sell the power for anything close to the full rates it charged to a member cooperative. That happened in the Tri-State case, and the court awarded damages -- to be paid by the utility that purchased the co-op's lines and was serving the co-op's members.

If a co-op retail member breached his obligations to buy all his power from the co-op, presumably the co-op could sue him for damages. It could also end his membership under its bylaws and thus deny him any co-op power.

Although the result in Tri-State may seem somewhat unusual in contract law, the result does make some sense if one considers that the distribution co-op is owned by its customers. So, by deciding simply to put the co-op out of business, the "owners" did not stop using electricity. They just changed their supplier and breached the requirements contract.

If specific performance were imposed by a court, breaching a requirement contract would not do anything for the buyer except cost it attorneys fees. But, if only damages were assessed, it might well be to the advantage of the co-op to breach, depending on the circumstance. It depends on the energy market.

III. Possible Need for Federal Legislation

Thus, in the Tribe's situation, if a valid tribal regulatory order directed the Reservation's utility to accept additional WAPA power if available or to purchase some other non-Rushmore power, the utility might well not be guilty of breach. However, such a decision would likely lead to litigation. There is no guarantee what a court would do.

It would be preferable for the Congress to enact legislation authorizing the Reservation's utility to accept WAPA power.

IV. Obtaining a Tribal Allocation Directly From WAPA

The federal hydroelectric facilities on the upper Missouri generate about 2000 megawatts of firm electric power. By comparison, the local RECs serving the reservations each has peak loads of less than ten megawatts. This federal hydroelectric power is marketed by WAPA at very low rates in South Dakota compared to Basin's and Rushmore's cost. Clearly, tribal members' electric costs could be brought down significantly if the tribes could obtain part of the inexpensive WAPA power.

WAPA is directed by the Reclamation Act, 43 U.S.C. § 485h(c), and the Flood Control Act of 1944, 16 u.S.C. § 825s, to give preference in the sale of power to "municipalities and other public corporations and agencies; and also to cooperatives, 43 U.S.C. § 485h(c), and to "public bodies and cooperatives. 16 U.S.C. § 825s. The Tribe, as a government organization, a "public body," qualifies under statutory law as a preference customer of WAPA. The Interior Solicitor reached that conclusion, at least with respect to Section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. § 485h(c). See "Indian tribes as preference customers under the Reclamation Project Act of 1939," M-36771 (July 25, 1967, reprinted in Dept. of Int., II Opinions of the Solicitor at 1968. The Solicitor concluded that a tribe was a self-governing sovereign entity carrying out the obligations of a local government and should be treated as a preference customer.

WAPA, however, has erected a second test that a tribe or any other "public body" must pass to obtain a power allocation. WAPA requires that any public body, other than an agency that consumes all the power itself, like a school, must operate a utility distribution system that serves ultimate retail customers and must undertake the typical responsibilities of a utility. This requirement is not explicit in the statutory law. This suggests that the tribes would have to take over the local RECs to become preference customers. But various state and federal institutions including universities, prisons, and military bases are preference customers. On the other hand, those institutions also use the power directly in their facilities. But Rushmore does not own any distribution facilities itself. Yet it receives a WAPA allocation. It simply transfers the WAPA power to local RECs.

A tribal electric marketing agency could do the same thing. The theory of such an organization is simply to buy the power and use another entity's distribution lines to transmit it to tribal members. In fact, the State of South Dakota considered setting up exactly this type of electric marketing agency to receive and sell WAPA Power. The State of Arizona already does this with federal power from the dams on the lower Colorado. This initially attractive concept has inherent difficulties for the tribes because of WAPA's interpretation of the preference statutory provisions.

WAPA's construction of the preference laws has been upheld in Salt Lake City v. WAPA, 926 F.2d 974 (10th Cir. 1991). Of course, even if the Tribe could set up arrangements, through acquiring utility status, that meet WAPA's test, WAPA is not obligated to sell power to it. The courts, in fact, have held that WAPA's choice among preference customers is not even subject to court review. Arizona Power Authority v. Morton, 549 F.2d 1231 (9th Cir.), cert. denied 434 U.S. 835 (1977); City of Santa Clara v. Andrus, 572 F.2d 660, (9th Cir. 1978).

V. WAPA Prior to the Year 2000

Given its low price, it is not surprising that the demands on WAPA exceed the supply of electricity it has available. As a result. WAPA has had to ration out the inexpensive federal hydro power, giving customers only part of what they would like. In addition, WAPA has signed contracts which appear to commit most if not all of its electric resources to existing customers through the year 2000. WAPA's position is that it is fully committed and has no firm electricity it can allocate to new customers.

Despite these assertions by WAPA, its contracts with its customers clearly indicate that their allocations should have declined at the end of 1990 to free up capacity which was expected to be needed by irrigation projects. Because those irrigation projects have not materialized, this power could be allocated to new preference customers including the tribes. This, however, will not happen automatically. WAPA, at this point, unless the recent interest of the Chairman of the House Committee on Natural Resources can effect change in the Department of Energy and WAPA, intends to simply allow existing customers to keep using this power.

Because the demand exceeds the supply, WAPA has always been very careful to minimize potential customers expectations. During the 1980s when the allocations that went into the 1985-2000 contracts were set, WAPA primarily decided to simply let existing customers continue using their original allocations, adjusting them across the board to accommodate any decrease in power availability. WAPA was very careful not to open up the allocation process to all potential customers. It did, however, increase its projected capability slightly to accommodate several small new customers. Thus, there appears to be some flexibility in the process that could accommodate the size of the loads that the tribes might place on WAPA prior to the end of this century.

Since Rushmore already received a WAPA allocation, WAPA may argue that the tribes cannot apply for a separate allocation at this time. Given that the tribes would be seeking to replace the Rushmore electricity along with the WAPA allocation contained in it, this would not seem to be a very convincing position. The tribes would not be seeking to "double dip." In addition, the tribes were not in a legal position to seek an allocation back in 1958 or 1965 when the existing allocations were set.

WAPA, with the political backing of its existing customers, is likely to resist any reduction in allocations to existing customers to facilitate the addition of new customers. The strength of this resistance to "tampering with" the existing WAPA allocations can be seen in the State of South Dakota's ongoing effort to obtain the benefits promised to it under the Pick-Sloan Plan. The governor and legislature of South Dakota have been seeking compensation for the state for the costs that the inundation of prime farm lands behind the mainstem Missouri dams imposed upon South Dakota. But in analyzing the alternative ways in which South Dakota might be compensated by the federal government, the legislature has excluded any arrangement that would either raise the price of WAPA power or reduce the allocations of WAPA power existing customers get. Even though the primary beneficiaries of WAPA reside outside of South Dakota and even though the State of South Dakota would be receiving significant benefits from any compensation arrangements, the political power of existing WAPA customers is such that the State of South Dakota is not willing to challenge the existing distribution of WAPA benefits even if this means that most attractive and feasible compensation plans have to be abandoned.

Unless WAPA has had a major change of heart, the Tribe will face the same political resistance when it seeks access to WAPA power directly. The special circumstances of the Tribe and the small size of its loads, however, has not made the Tribe's requests appear less threatening.

VI. The Oglala Tribe's Recent Experience With WAPA and Related Political Forces

Section 9(a) of the Mni Wiconi Project Act of 1988, Pub. L. 100-516, mandates that all the systems authorized by that Act (including the Oglala Sioux Rural Water Supply System) use Pick-Sloan power for operation and mandates that this power be a requirement of pick-Sloan. Section 9(b) of the Act mandates that former Pollock-Herreid Unit power be reserved for the systems and made available for their operation.

Although a 1980 Reclamation report identified six megawatts for the future Pollock Herreid project on a seasonal basis, i.e., just during the irrigation season, the Bureau of Reclamation agrees that "the intent of the Mni Wiconi Act, P.L. 100-516 and specifically section 9 was to provide Pick-Sloan power for project use on a year-round basis." October 25, 1933 letter, Daniel P. Beard, Commissioner, United States Bureau of Reclamation, to Fran Ayer, Pirtle, Morisset, Schlosser & Ayer. The Tribe, with its legal counsel and consultants, developed and presented to WAPA extensive legal and practical arguments, but all attempts by the Tribe to obtain the commitment of WAPA to supply the six megawatts on a year-round basis were met with absolute refusals.

The decision was made by the Tribe and the South Dakota congressional delegation to clarify the original intent of Pub. L. 100-516 in amendments to that Act. H.R.3954 and S.2066, 103d Congress, 2d Sess. (1994), are now pending. H.R. 3954 was introduced with the provision clarifying that the six megawatts are to be supplied on a year-round basis. It would be difficult to describe the political forces unleased upon the South Dakota delegation by that provision. The opposition came from the lobbyists of the rural electric cooperatives, primarily Mr. Thomas Graves, Executive Director, Midwest Electric Consumers Association, Denver, Colorado. All attempts by the Tribe to meet rational concerns of the REC's representatives, such as demonstrating the nominal effect on rates of REC consumers and even drafting bill language to protect ratepayers from any increases, were totally unacceptable to Midwest Electric. It was clear that their concern was irrational. Moreover, it was clear that their political power was real. In order to secure passage of the Senate bill, S.2066 was introduced without the clarifying provision and the provision will be deleted from H.R.3954 at mark up.

That six megawatts causes such opposition from WAPA and the RECs demonstrates the necessity for the courageous leadership which Chairman Miller is showing. The Tribe needs a champion willing and able to take on the irrational forces of opposition to an equitable allocation of WAPA power both for the year 2000 and even before to the extent that power capacity is available.

VII. Three Basic Reasons for Overcoming the Forces Against a Reallocation of WAPA Power

Simply stated, the Oglala Sioux Tribe retains substantial water rights to the Missouri River, the benefit from which they have never seen. "Tribal water," on the other hand, is now used by others to generate massive amounts of power. The Tribe deserves some of the power thus generated.

As a legal matter, this argument is not likely to lead a court to force a WAPA allocation to Oglala. The Tribe's treaty water rights are a separate entitlement and the Tribe is free to assert its treaty rights in court or the Congress. As the Tribe testified at the June 16 hearing on behalf of Mni Sose, equity is absent in water rights litigation and negotiation in state courts under the McCarran Amendment, 43 U.S.C. § 666.

As a moral and political matter, the argument is compelling. It starkly reveals the inequitable uses to which the Missouri River has been put and emphasizes how little the Tribe has seen by way of benefits, despite the fact that the denial of tribal access to water has made it possible to generate electricity with tribal water. At a minimum, the treatment of the Tribe with respect to water and power from the Missouri River hardly comports with the high fiduciary standard that should apply to the United States as the Tribe's trustee.

The Oglala Sioux Tribe wishes the record to be absolutely clear, however, that any allocation of WAPA power would be in the nature of royalties for the use of its trust resource. Such an allocation would not be compensation for the Tribe's treaty water rights which the Tribe resolutely retains.

A second argument for an additional allocation to the Reservation actually sweeps larger than the Reservation itself. The "South Dakota equity" argument is essentially this: South Dakota lost hundreds of thousands of acres of land to Pick Sloan projects which now produce WAPA power. A major portion of that land was Indian land. The primary benefits of those projects, however, have flowed downstream, in the form of navigation and flood control; to the states of Iowa, Nebraska, and Minnesota in terms of cheap energy (South Dakota receives 17 percent of the Pick Sloan electricity from South Dakota dams) and to Nebraska and North Dakota, in terms of irrigation. In return for sacrificing much land, South Dakota expected several hundred thousand acres of irrigation improvements. Most of that irrigation never materialized.

Given this disproportion between the Indians' and South Dakota's burden and benefits from the Pick Sloan program, it seems fair that the State, including the tribes, should receive a greater share of WAPA power. Not much more federal irrigation development will ever take place.

Past State efforts to explore equity options for obtaining a larger share of Pick Sloan power have met with fierce political opposition from the RECs and municipal electricity utilities even in South Dakota because they were unwilling to support options that might have helped them at the expense of their brother and sister utilities outside the State. Their may be some future, however, in a political alliance between the tribes in South Dakota and those parts of the State political spectrum willing to demand changes in WAPA programs.

A third compelling reason for an additional WAPA allocation for the Pine Ridge Reservation is simply the dire economic circumstances in which the Reservation finds itself. Shannon County, where the bulk of the Oglala Sioux Indians live, has been classified the poorest county in the United States. The hardships suffered each winter are heart rending as the cold weather sets in and electric bills eat up every available dollar or simply go unpaid until service is terminated.

Economic benefits that could be realized by the Oglala Sioux if wholesale, preference power were made available are many, some at this point theoretical and yet to be identified. However, a project already conceived by the Tribe is the establishment of a an Oglala Sioux pottery factory.

Every year, tourists who visit the Black Hills purchase Sioux pottery from local pottery stores. Many of these stores hire Sioux Indians to design the pottery, with distinctly Sioux designs.

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Much of the cost of making pottery is in the cost of purchasing clay and electricity for the kilns. The Oglala Sioux Tribe already owns lands that produce some of the highest quality clays available in the United States. It also has the manpower and talent available to design and make pottery. If the Tribe were able to acquire cheap electricity from WAPA, it would have the three main ingredients necessary to establish a pottery company that could make Sioux pottery and market it nationwide at reasonable cost.

VIII. All Other Points Aside the Tribe Preserves Its Option to Establish a Tribal Utility

Many Tribes in the Missouri River Basin, including the Oglala Sioux, have or will undertake steps to partition and acquire parts of existing RECs and may also build distribution lines. The Oglalas do own a substation which serves the Village of Pine Ridge. It is presently leased to Nebraska Public Power. In addition, § 3(a)(7) of Pub. L. 100-516 recognizes tribal authority by authorizing the Oglalas to construct electrical power transmission and distribution facilities necessary for services to the Mni Wiconi water systems. Instances can be cited where the existing customer utilities have refused to wheel federal power to the tribes even should the tribes be able to achieve a WAPA allocation. In addition to the problem of the requirements contracts, WAPA and its existing customers have focused on the lack of tribal utility status.

Assuming the WAPA utility requirement will be resolved due to the efforts of the tribes and Chairman Miller, the Oglala Sioux Tribe nonetheless wishes to preserve its option to establish a tribal utility for its long-range planning and benefit. There are other advantages associated with establishing a tribal electric utility, one important advantage being the reduction in the cost of electricity to tribal members.

The local RECs' current exclusive source of supply is the Rushmore Electric Power Cooperative. Rushmore, in turn, obtains its electricity from two sources: Basin Electric Cooperative and WAPA. Only 13.5 percent of Rushmore's electricity comes from WAPA.

Another important reason for setting up a tribal utility is the extension and exercise of tribal sovereign powers in the provision of a basic necessity to tribal members. Electric supply is like roads, water supply, and sewage disposal: it is part of the basic infrastructure of a modern society. That is the reason it is entrusted to either public or quasi-public organizations or regulated by the state. Just as many municipalities in South Dakota are served by municipal utilities and the entire state of Nebraska is served by a public power agency, the Tribe may wish to control and operate the electric utility serving the Reservation.

This is more than a desire to make a symbolic gesture of sovereignty. With the operation of a tribal utility will go opportunities to make real changes in how the utility impacts tribal members and the Reservation. Operating the utility will allow the Tribe to develop managerial and

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technical skills and see that more of the jobs associated with this basic technology are filled by tribal members.

In addition, the policies of a tribal utility could deal more directly with specific reservation problems. For instance, a tribal utility could seek to minimize the "leakage" of funds off of the Reservation by supporting real conservation programs that make the Reservation more self-sufficient. This contributes to basic economic development. In addition, a tribal utility could seek to design its rate structure, hook up, and disconnect policies to recognize the extent of low income problems on the Reservation. Finally, to the extent that other tribes in the Northern Plains also set up tribal utilities or tribal electric marketing agencies, it is also possible that business coalitions of tribal utilities could develop future sources of supply using reservation resources. This would give the tribes still further experience in business and public administration, allow them to make greater use of their resources, and lower their costs of electricity.

The Tribe itself, of course, will have to weigh the potentials, risks, and burdens and make its own informed decision about its future.

On behalf of the Tribe, we would like to say that your advocacy on this issue is greatly appreciated and, it is fair to say, without precedent.

Sincerely,

PIRTLE, MORISSET, SCHLOSSER & AYER

Fran Ayer

M. Frances Ayer

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Sisseton-Wahpeton Sioux Tribe

LAKE TRAVERSE RESERVATION

BIG COULEE • BUFFALO LAKE • ENEMY SWIM • HEIPA/VEBLEN • LAKE TRAVERSE • LONG HOLLOW • OLD AGENCY

June 29, 1994

Honorable George Miller, Chairman
Natural Resource Committee
U.S. House of Repersentatives
Washington, D.C. 20515

Dear Chairman Miller:

The Sisseton-Wahpeton Dakota Nation along with the other Missouri River Basin, tribes in support of an allocation of Western Power to the tribes and their membership. Not unlike others in the Missouri River Basin, The Sisseton-Wahpeton Dakota Nation have electrical rates on the Lake Traverse Reservation that are higher then our people can afford.

Our income levels are simply inadequate to pay the high cost. Federal power, which Western sells at whole sale price of 14 mils per kilowatt hour, is significently lower in cost than that recieved through our electrical utility at a cost of 35 to 40 mils per kilowatt hour.

Although not statutory requirement, Western has historically allocated power to utilities only. The Sisseton-Wahpeton Dakota Nation does not qualify as a utility but does meet the statutory test for preference status. Western's judgment has been reviewed by the courts, and the decisions are consistently in favor of Western on the basis that Congress has not defined the means of allocating preference power. Therefore, Western is without limitation on the judgments that it can exercise with regard to the allocation of electricity to preference customers. Historically, Western has not allocated electricity to the Indian tribes of the Missouri River Basin, including the Sisseton-Wahpeton Dakota Nation, on the basis that we are not a utility.

We appreciate the oversight by your Committee into this matter and gain hope that changes can be made. We are encouraged by the statements made during your hearing on June 16, 1994

Sincerely,

Arnold R. Ryan, Tribal Chairman
Sisseton-Wahpeton Sioux Tribe
also Known as Sisseton-Wahpeton
Dakota Nation

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June 29, 1994

Honorable George Miller
Chairman
Committee on Natural Resources
1324 Longworth House Office Bldg.
Washington, D. C. 20515-6201

Dear Chairman Miller:

The Standing Rock Sioux Tribe located in North Dakota and in South Dakota, respectively, and along the Missouri River does support for an allocation of Western power to the Tribes and their membership. Unlike others in the Missouri River Basin, the Standing Rock Sioux Tribe was promised "free electricity" when the land was taken in 1957, but now we have electrical rates on our Reservation that are higher than what we can afford.

Income levels are simply inadequate to pay the high costs of power. Federal power, which Western sells at a wholesale price of 14 mils per kilowatt hour, is significantly lower in cost than that received through our electrical utility at cost of 35 to 40 mils per kilowatt hour.

Although not a statutory requirement, Western has historically allocated power to utilities only. The Standing Rock Sioux Tribe does not qualify as a utility, but does meet the statutory test for super preference power. Therefore, Western is without limitation on the judgments that it can exercise with regard to the allocation of electricity to preference customers.

We do appreciate the Oversight by your Committee into this matter and hope that changes can be made so the Standing Rock Sioux Tribe can receive super preference power allocation from Western.

Respectfully,

Jesse Taken Alive, Chairman
Standing Rock Sioux Tribe

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