BPA COMPETITIVENESS

OVERSIGHT HEARING

BEFORE THE

TASK FORCE ON
BONNEVILLE POWER ADMINISTRATION

OF THE

COMMITTEE ON
NATURAL RESOURCES
HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRD CONGRESS

FIRST SESSION

ON

COMPETITIVENESS OF THE BONNEVILLE POWER ADMINISTRATION

HEARING HELD IN EUGENE, OR
SEPTEMBER 25, 1993

Serial No. 103–20 PART IV

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APPENDIX

September 25, 1993

COMPETITIVENESS OF THE BONNEVILLE POWER ADMINISTRATION

SATURDAY, SEPTEMBER 25, 1993

HOUSE OF REPRESENTATIVES,
TASK FORCE ON BONNEVILLE POWER ADMINISTRATION,
COMMITTEE ON NATURAL RESOURCES,
Washington, DC.

The task force met, pursuant to call, at 9:30 a.m. in the Council Chambers, City Hall, Eugene, Oregon, Hon. Peter DeFazio (chairman of the task force) presiding.

STATEMENT OF HON. PETER A. DeFAZIO

Mr. DEFAZIO. Let us get started. We have got 17 witnesses and a lot of ground to cover. We hope to get out here while the sun is still shining so some people can enjoy this fabulous fall day.

I have a brief opening statement, then Mr. LaRocco may want to say some opening words and then we will move on to the witnesses.

First a little bit about procedure. Those who were in Boise yesterday or who have testified before know you have allocated time. I usually start these hearings by saying that I have read every piece of testimony. In this case because of the press of business, I have not read all of the testimony, but I have read most of it. It is most helpful if you summarize your statement. Yesterday, we had some very good dialogue where subsequent witnesses commented on, rebutted or expanded upon points made by prior witnesses. That is always very helpful to the committee. So it is your time to use as you wish. If you want to just plod through a prepared statement, that is fine. If you can be more spontaneous, that is great. When the yellow light goes on you have got one minute. When the red light goes on you are done. We will strictly enforce the time lines, and you will get to finish your sentence essentially.

This is the fourth hearing of the task force. Yesterday, in Idaho, we did a hearing entirely devoted to the issue of salmon and the related factors that affect the system in the Northwest, particularly river flows and drawdowns and a number of other issues, and debated a lot of biology. Today, issues are more nuts and bolts, and perhaps go a little bit more to the heart of the future of the provision of power supply in the Pacific Northwest.

I have had some people in the industry say to me, well, why all this talk about competitiveness and why the changes that are being proposed? Why can things not be the way they are? We have even had some testimony in a couple of hearings to that extent, or why can they not be the way they were? Well, the world is changing

very quickly around us, and those who followed the Energy Act last year know that I was one of the few conferees to vote against it. There is some good in that and some bad in it and there are some real imponderables. One of the great imponderables for us in the western United States is what it is going to do in terms of transmission in this movement toward open access of transmission and what that means for power providers and purchasers in the West. In fact, I just heard about a move by a very large multinational firm that is looking at setting up a power futures market in the western United States, dependent upon wheeling. We might even go beyond that. You know, there was a day in Springfield, where I live, where we had retailers competing street by street, house by house. There is a question of whether or not we have created that with the Energy Act that passed last year, which I am afraid that many of my colleagues did not fully understand.

So the times are changing, and BPA and the rest of us are going to have to change with them. So, it is very timely to discuss the competitiveness of BPA. Vice President Gore has proposed to—I hate it, but he calls it reinvent BPA. BPA has its own competitiveness review going. We are beginning to question the way we have done things and how we are going to do them in the future. But one thing needs to underlie all of this, and the first witness, I think, will underscore it. That is, in my very strong opinion, anybody who thinks that we are going to have competitiveness, unbundling of services, or reinvention of BPA as a way to get out from the mandates of the Northwest Power Act is dead wrong. At least, I will do my best in the United States Congress to see that does not happen. I think the Act was right on target, and that was one of the reasons I voted against the Energy Bill last year. It was not enough on target in moving this country toward a long-term conservation, renewable, affordable energy power path, including good consideration of environmental impacts. The Northwest Power Act did that. That is not to say there will not be dramatic changes, but it will shape those changes. So those few recalcitrants out there who hold out the hope that this is the way to escape from those mandates, that is not going to happen. So adjust your thinking a little bit and work creatively with us as we grow into the next century.

With that, I first will see if my colleague Mr. LaRocco has any opening remarks.

STATEMENT OF HON. LARRY LaROCCO

Mr. LaRocco. Mr. Chairman, you had brief remarks and I have even briefer. I just want to thank you for being in Boise, Idaho, yesterday to discuss the salmon issue. I am pleased to be in your district, and to the people of your district, I just want to say as a colleague and member of the Natural Resources Committee, there is not another member in the whole House of Representatives who is more familiar with these issues than you. I look forward to the testimony today. This is an issue of great interest to me. I do not have the grasp of it that you do, so I will be listening intently. I am very pleased to sit on the task force with you. I think you are doing a great job and I look forward to it.

Mr. DeFazio. I thank you for being here, Larry.

With that, I am going to move to the witness list. I would just like to give a brief introduction. I do not usually do introductions of witnesses, and this is one that really does not require one, but I just feel that it would be appropriate.

Jim Weaver is familiar to most of you. He is my former boss. In part, my early interest in and knowledge of power issues came from working with Jim, particularly during the struggle over the Northwest Power Act. And I would say that if acts have fathers—and I do not know whether we really can say that—Jim would be the father of the Act and the principal architect in the House of Representatives. I am really pleased to have him here today to lead off the witnesses in what will perhaps be the next round of historic changes in the way we look at our power system in the Northwest.

With that, the Honorable Jim Weaver.

STATEMENT OF HON. JAMES WEAVER, FORMER REPRESENTATIVE IN CONGRESS FROM THE STATE OF OREGON

Mr. WEAVER. Thank you, Mr. Chairman. I want to compliment Chairman DeFazio and his distinguished colleague, Congressman LaRocco, for setting up and establishing this watchdog committee. I think that is a marvelous thing that you have done, Mr. Chairman.

The BPA needs watching. It acts like a private utility, not a public agency. Indeed, it is closer to the utilities than the public it supposedly represents. You know, Chairman DeFazio has a long history of keeping the BPA in line, all the way back to his suit on net billing, which is long forgotten now, but was an accounting ruse he saw rightly as an underhanded way to finance the WPP nuclear plants with tax dollars and electric bill dollars without voter approval. That is why the BPA needs watching, because they can do so many things without the public being represented.

Indeed, when I filibustered the Northwest Power Bill in the House in 1980, one of my key amendments—that is how you filibuster in the House, as you know. I had 115 amendments, each allowing me five minutes. One of my key amendments was to require voter approval of any BPA-backed bond issues. Oh, did they fight back. This public agency and their utility allies did not want and do not want the public to have any say in their empire building, but the public had to pay for it. Our electric bills are at least twice as high today because they spent our money like water on WPPSS without voter approval.

Chairman DeFazio and I studied the history of the BPA. We read the Congressional debate in 1937 when the BPA Act was up for consideration in the House. Leading the debate was that grand old man of Oregon politics, former Governor Walter Pierce, a fighting populist who went on to serve four or five terms in the House. Do you know what Congressman Pierce said in that debate? He said quote, "The BPA"—it was being established by the Act—"will be the people's agency to provide everyone with low-cost electricity." Now that was nice. But in that same debate, Pierce, wise in the ways of government and power added the oppression clause. "But I know," he said in the floor of the House, "that in a matter of years, the BPA will be captured by the utilities and corporate inter-

ests and taken away from the people." And, of course, that happened. Even the small public utilities were captured.

Once at a convention, I actually heard a former BPA administrator, Charlie Luce—it was here in Eugene in a speech to hundreds of people—Luce said, quote, "The people are our enemies." He was applauded. This was in 1980. What he meant was that they wanted to build a more, bigger and costlier empire, and public groups were trying to stop them. Has the BPA changed today? Not much. It is obvious it still regards itself as an arm of the utility industry. Its halfhearted attempts at conservation amount to little more than lip service. Utilities want to sell more electricity. Certainly, that is their job. I understand that. But BPA is not a private utility.

Mr. Chairman, I would like to make a proposal for legislation affecting the BPA. This legislation harkens back to another amendment I offered during the filibuster of the Northwest Power Bill, and this amendment almost passed. The vote in the Interior Committee—which you now call the Natural Resources Committee—the vote in the Interior Committee was 21–21—I had to go over to the floor of the House and get Austin Murphy, who promised to vote with me, back to make it 21–21. And that was under intensive lobbying against it by the utility industry and its allies. Indeed the *Oregonian* newspaper was adamantly opposed to it. But I saw recently that the *Oregonian* had editorialized for the approach I am about to mention, and it is called two-tier rates.

I first introduced the idea of two-tier rates over 20 years ago. By the way, both for gasoline as well as electricity. It is something I think that would go a great way toward resolving most of the conservation issues that we face. Let me explain briefly how two-tier rates work. They mean simply that the first amount of electricity you purchase is at a low rate. If you are prudent with use of electricity and use conservation methods, you may have only to pay that low rate. Those that use more electricity would pay a much higher rate. They would be penalized for extravagance. The utility itself would adjust these rates to receive on average the same amount of dollars they would under any other rate structure.

When I first introduced this 20 years ago, the utilities screamed that poor people with leaky houses would bear the brunt of this approach. It was, of course, the first time utility executives ever concerned themselves with poor people except to cut off their electricity when they did not pay their bills. The answer to this, of course, is to insulate those leaky homes, providing, by the way, lots of jobs in local communities.

There are, of course, Mr. Chairman, many complications involved in two-tier rates, but there are just as many complications in present rate structures. BPA under legislation could strongly motivate local utilities to implement two-tier rates while leaving precise details to the local communities. I encourage the Chairman, if he has not already done so, to introduce a bill requiring BPA to implement two-tier rates.

In closing, I have always hoped that my local utility, EWEP, would do this. It is another public agency that also acts like a private utility.

Mr. Chairman, Congressman LaRocco, I again want to compliment you for this hearing, for your watchdog committee on the BPA, and commend you and thank you for the good work you are doing.

Mr. DEFAZIO. I thank the gentleman. I think the statement is pretty self-evident. I do not have any questions. Do you?

Mr. LAROCCO. I do not have any questions.

Mr. WEAVER. Thank you very much.

Mr. DEFAZIO. Thank you.

We will move on to the next panel which will be Randy Hardy, Tom Trulove and Ms. Judith Merchant. Angus Duncan will be accompanying Tom Trulove.

We will go in order of the list here. We will start with Administrator Hardy.

PANEL CONSISTING OF RANDALL W. HARDY, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION; TOM TRULOVE, WASHINGTON COUNCIL MEMBER, NORTHWEST POWER PLANNING COUNCIL, ACCOMPANIED BY ANGUS DUNCAN, OREGON COUNCIL MEMBER; AND, JUDITH MERCHANT, DIRECTOR, WASHINGTON STATE ENERGY OFFICE

STATEMENT OF RANDALL W. HARDY

Mr. HARDY. Thank you, Mr. Chairman, and thank you particularly for the opportunity to discuss Bonneville's competitiveness and some of the changes that are going on in the utility industry.

As you mentioned in your opening statement, we have been engaged for about the last eight or nine months on what we called our Competitiveness Project. Before we get into some of the details of what is involved with the Competitiveness Project, I think it is important to explain why we are concerned today and in the future about Bonneville's competitiveness. There are three reasons, from my perspective, driving this concern.

First is the double-digit rate increase we are putting into effect on the first of October for all of our customers and the effect, it will have on our customers and on the region's economy. Our customers, whether they are direct service industry (DSI) small businesses or large industrial customers of retail public utilities, are facing increasingly global competition in their own marketplaces; shrinking price margins; enhanced, heightened sensitivity and heightened impacts to our rate increases. That is one set of reasons why we are concerned about our competitiveness—the residual impact on our customers' competitiveness. This has been pretty consistent throughout the last 20 years or so; although, the global marketplace is making that competition even fiercer.

The second reason involves what is going on in Washington, DC, right now concerning the reinvention of government. It is clear the Clinton Administration is taking a major initiative to try and overhaul the Federal Government in talking about cutting 250,000 Federal employees and when talking about the potential of government corporation status for Bonneville, debt buy outs, and other kinds of alternatives. As part of the Vice President's national performance review effort, we have been designated as one of 17 reinvention laboratories by the Administration. The basic quid pro quo there is,

you volunteer to be a reinvention guinea pig and, in theory at least, get some relief from governmental administrative regulations. That is precisely what we are seeking, and that is precisely why we have advanced ourselves to be a reinvention candidate. Rather than being a passive actor, we thought a more activist approach in trying to shape our own destiny in this regard would be the most appropriate course to follow.

Finally, the third and probably principal reason why we are concerned about our competitiveness has to do with the changing utility marketplace. There are fundamental changes going on in this industry. As an electric utility in the 1990s, we will see structural changes very similar to what the airlines, the phone companies, and the gas companies have been through in the 1980s. You only have to look at what has happened to those industries to get some idea of the magnitude of that change. And the change will come quite rapidly. A couple of our colleagues have used the analogy of the Berlin Wall. It does not come down one brick at a time. It happens quite rapidly. And that is the kind of change we anticipate.

What are the factors that are causing that change? I believe this is the essence of what we need to understand and try to grapple with. I will explain them as best I understand them. First is cheaper gas and the competitive advantage it is providing for combustion turbines and cogeneration facilities in the utility marketplace. Five years ago, the marginal cost resource was a coal plant at 5 cents a kilowatt hour. Today the marginal cost resource is a combined cycle gas turbine at 3–3.5 cents a kilowatt hour when our wholesale rate is at 2.7 cents after the latest rate increase. While we are still the low-cost supplier, that margin is shrinking and customers have new competitive alternatives that are very close or getting close to what our Priority Firm (PF) rate is.

Second is the proliferation of independent power producers. The generation side of the electricity market is basically deregulated and the competition is fierce. I think you can question some of the other witnesses today who have had experience in acquiring resources through independent power producers (IPPs) to get some idea of that. But just to give you one example, between the time of our competitive bid 18 months ago in which we selected the Tenaska Project and the resource contingency plan which we executed earlier this year which provided options, the costs have gone down, not up, in terms of the costs and the potential prices of resources. This is a declining-cost industry with all of the implications which that provides relative to our competitive position.

The third reason, Mr. Chairman, is the one you alluded to. There are new players coming into this marketplace. Let me cite two examples. We are buying power today from Louis Dreyfus Company. Louis Dreyfus is a French-owned multinational firm that is in the tanker business and the oil and gas business. They own a lot of gas and a lot of oil, and they have looked at the West Coast marketplace. They have leased generation, and now they are matching the gas up with the leased generation and they are looking around for people to sell the electricity to. They are undercutting other suppliers by a mil or two here and there. You are going to see those kinds of marketplace entrants increasingly. About two months ago, we were visited by representatives of the New York Commodities

Exchange. While I think they have a ways to go in understanding some of the institutional constraints relative to the Northwest Transmission System, they clearly see market potential for setting up a commodities exchange or a commodities future market 3 to 5 years down the line. These are players that are the equivalent in our industry of the MCIs and the Sprints and other competitors in the telephone industry. I think that will give you some idea of the degree of structural change that is occurring.

The fourth element of this is last year's Energy Policy Act which you alluded to, Mr. Chairman. That basically has opened up transmission access at the wholesale level in electrical generation. While there are some protections in there for the Northwest, they are limited. They are limited to existing firm-load customers and compensation for transactions that would cause us to spill. That leaves a whole volume of transactions that are still at risk.

Finally, there is the logical extension of open transmission access and retail wheeling. Whether or not that comes to pass is a hotly debated topic, but it certainly is a logical extension of the kind of deregulation that we see occurring.

The two basic competitive risks that we see are the traditional risks we have always had, that if our rates get too high, our customers go out of business, whether it is the DSIs or a pulp and paper mill of a public utility customer of ours, or a small business, or an agricultural concern. That has not changed much; except as I explained earlier, the price margins are shrinking.

We have got two other fundamental risks that are new however. One is the threat that customers will see turbines and other kinds of new resource alternatives as being more attractive and less risky than buying power from Bonneville. In fact, we see that today. Even though, we have not reached the crossover point with Bonneville priority firm rate and the cost of resources, Clark County PUD, Snohomish County PUD are out with request for proposals for their own resources. Eugene has its own resource plan that contemplates substantially greater independence from Bonneville. Columbia Falls Aluminum Company has gone out with a request for proposal to provide up to 40 percent of its power potentially from other sources than BPA.

The second type of risk, beyond customers going off our system and our losing revenue associated with that, are the consequences of open transmission access. As I mentioned before, we can protect our existing firm-load customers and we can get compensated for spill that is caused by transmission access. But that leaves a whole volume of transactions, non-firm transactions, and possible-firm transactions, including seasonal exchanges for fish or other kinds of revenue enhancing possibilities, that have to compete in that marketplace with the Louis Dreyfuses of the world or those other kinds of transactions. That category of additional transactions, both firm and non-firm, is literally the margin that will determine whether we are successful and competitive or not. And those are the transactions that are at risk in a fundamentally different way in an open-access transmission market than has been the case before. That is the nature of the competitive circumstance and the competitive threat we see. What are we going to do?

We are going to do three things. We are going to get ourselves more efficient, and as part of that exercise, we announced on Monday to the Bonneville work force that we are going to downsize by 600–800 employees saving $75–100 million. That is a 15 percent downsizing over the next 4 years and is similar to what other utilities have done. Furthermore, we are going to unbundle our services to try to create a greater mix of products and services. And in that context we are moving in the direction that former Congressman Weaver suggested in terms implementing some sort of tiered rate structure. And we are going to change our culture.

I would like to discuss the next steps in this process. We have some graphics to illustrate this. The development of a business plan with strategic business objectives, development of a marketing plan, and a function-by-function review illustrate the efficiency exercises we are going through.

I will just conclude by making one basic observation. Change is inevitable. We can either take advantage of it and bend it to our needs and realize that opportunity, or we can be victimized by it. The failure to take action has serious consequences. First, it is uncoordinated resource development. It is customers going out on their own, and it is a dramatic departure from the structure that the Regional Act envisioned with the NW Power Planning Council involved in resource planning. Second, it is increased rates with all the consequences. Third, it is missed Treasury payments with all the political consequences attendant with that. Fourth and finally, it is unstable or declining fish funding and funding for our other environmental obligations. While that is a worst-case scenario, it is a very realistic one. That is what we seek to avoid.

Thank you, Mr. Chairman.

Mr. DEFAZIO. Thank you.

Mr. Trulove.

[Prepared statement of Mr. Hardy follows:]

STATEMENT OF RANDALL W. HARDY

BONNEVILLE POWER ADMINISTRATION

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE BONNEVILLE POWER ADMINISTRATION TASK FORCE

HOUSE COMMITTEE ON NATURAL RESOURCES

FIELD HEARING - EUGENE, OREGON

SEPTEMBER 25, 1993

Printed on 100 percent recycled paper

Statement of Randall W. Hardy, Administrator
Bonneville Power Administration
September 25, 1993

Chairman DeFazio, it is again my pleasure to appear before the Bonneville Power Administration Task Force.

My testimony today will focus on the challenges and opportunities facing Bonneville in this rapidly-evolving industry, and how Bonneville is adapting to them. The changes that are occurring leave Bonneville with no choice but to change fundamentally. The good news is that by becoming more market-driven, customer-focused, cost-conscious, and results-oriented, Bonneville can expand the benefits it has provided the region for the last 57 years, without fundamentally changing the agency's mission. The more sobering news is that Bonneville's ability to carry out its mission may be impaired if we do not succeed in this change.

The changes required to ensure that BPA continues to expand the benefits it provides are significant. Today I will describe how we are identifying and creating the necessary changes, through Bonneville's Competitiveness Project.

Fundamental Changes in the Electric Industry Require BPA to Change

Bonneville must make changes in response to events that are sweeping the industry, or risk becoming increasingly irrelevant to our customers' needs, and therefore unable to play the key historical role of Northwest power provider of choice.

The costs of new power sources have come down steeply, causing the gap between BPA's costs and the costs of alternative power sources to narrow dramatically. Ten years ago, the costs of power from a new gas-fired combustion turbine were roughly 250 percent

higher than BPA's rates on a real levelized basis. Today, those costs are only roughly 25 percent higher. In addition, competitive new generation (including cogeneration) is available in smaller unit sizes, eroding the advantage of large, centralized power plants. One can argue that BPA is still the better deal, but the narrowing cost differential is cause for concern.

A strong, deregulated, independent power production industry has recently emerged. This industry provides every utility with a ready alternative to traditional wholesale suppliers such as Bonneville.

End-use consumers have more economic energy choices. In addition, new technologies are rapidly entering the marketplace, creating greater awareness of energy alternatives such as cogeneration and self-generation, increasing the choices available to end-use consumers, and increasing their ability to control their energy usage.

Most importantly, regulations regarding transmission are being changed dramatically. This is giving utilities greater access to alternative power suppliers, as well as allowing utilities to compete against BPA by buying and selling in the same markets.

The wave of deregulation that has swept over the airline and telecommunication industries is affecting the electric industry to perhaps even a greater extent. What changes deregulation will bring are not certain, but the clear lesson from other industries is that organizations which assume continuation of the status quo do not survive.

Bonneville Competitiveness is Critical

Bonneville's competitiveness is critical to the Pacific Northwest regional economy because we provide nearly half of the electric power and three-fourths of the high-voltage transmission in a very electricity-dependent region. Nearly 3 million people and over 1.2 million jobs in the region depend on Bonneville power.

Bonneville's competitiveness is critical to its customers because the competitiveness and survival of many of the 150 utilities and large industrial customers the agency serves in the region is closely linked to Bonneville's rate levels. Likewise, businesses and industries served by these utilities depend on an economic power supply.

Bonneville's competitiveness is critical to the environment because we contribute over $300 million per year to fish and wildlife, in addition to tens of millions for clear air, clean water, and hazardous waste cleanup.

Further, Bonneville's competitiveness is important to US taxpayers because of the annual payments of approximately $700 million Bonneville makes to the US Treasury.

The Alternative to Bonneville Competitiveness is Unacceptable

Bonneville customers are already looking for alternative sources of supply, and that is not necessarily bad for the region or Bonneville. Although Bonneville remains the best buy at present, the price advantage of BPA over alternative sources has narrowed greatly. In fact, our customers may very well be able to develop new resources as efficiently and economically as Bonneville. This, combined with the cost risks Bonneville faces, makes our customers' concern understandable.

A narrow price advantage for Bonneville power over alternative sources may not be enough to maintain our customers' willingness to buy from us. This is in part because of the risks they perceive in relying on Bonneville, and in part because of the value many utilities place on having an independent source of supply. Even if Bonneville rates have not yet reached the cost of new resources, customers will increasingly develop their own resources because of the uncertainties which the agency faces. These uncertainties include Endangered Species Act fish costs, possible repayment reform, and nuclear plant decommissioning costs.

Coordinated regional resource development in accordance with the Northwest Power Planning Council's Energy Plan is desirable if it minimizes costs and environmental impacts. However, such results will come about only if the plan and Bonneville's actions in support of it produce a product that is attractive to our customers.

If Bonneville fails to offer the best product at the best price, regional resource development will become more fragmented, undermining the effect of the Council's energy plan, and potentially impairing Bonneville's ability to pursue the environmental goals of the Council's Fish and Wildlife Plan. Further, to the extent there are efficiencies of coordinated regional resource development, these could be lost.

Creating a New BPA

Bonneville's Competitiveness Project is our vehicle for creating the necessary change in the agency.

The vision of the new more competitive Bonneville is still taking shape, but the outlines are coming into focus. At the first of these Task Force hearings, we discussed that

Bonneville must move from a program- and beneficiary-oriented government agency to a customer-focused, cost-conscious, results-oriented, market-driven organization.

In the past few months, we have fleshed-out this simple description of the new Bonneville, in the form of the draft set of Strategic Business Objectives. These Strategic Business Objectives are intended to be the drivers of all of Bonneville's work. Although they are still in draft, a few of the Objectives deserve highlighting. A copy of the Strategic Business Objectives is attached to this testimony.

Objective 2 focuses on the opportunity we see for Bonneville to continue to expand the benefits it provides the region. We can expand benefits by cutting costs, unbundling products and services, and providing new products and services.

The current regional debate seems to be focusing on how to divide a pie of fixed size among competing interests. Through this expansion of benefits, we have an opportunity to change the terms of the debate, by turning it into a discussion and collaboration on how best to expand the size of the pie.

Objective 3 represents an extremely important element if Bonneville is to be successful. We believe the current system does not create incentives, particularly in the short term, for non-customer stakeholders to seek and support activities that enhance Bonneville's competitive position. Yet in the long run, if Bonneville becomes uncompetitive, it will become increasingly difficult to generate funds for environmental mitigation, Treasury repayment, and normal operating expenses. We intend to work with our customers and other stakeholders to develop a system which creates short-term financial rewards for customers and for statutorily mandated, non-revenue producing programs as Bonneville's revenue producing programs become more successful.

Objective 5 indicates that the core basis for Bonneville competitiveness in the future will be the same as it has been in the past -- being the low-cost provider.

Objective 7 describes the environmental approach we envision. We plan to continue our commitment to fish and wildlife and other environmental goals. In fact, by expanding the benefits of our system, we will be better positioned to accomplish these goals. Conversely, if we do not succeed in our effort to maintain our competitive edge, Bonneville's financial ability to support these goals may be severely impaired. The Objective also expresses the necessity of ensuring that our investments in non-power goals produce measurable results.

Progress on a Marketing Plan

It is becoming increasingly clear that the old regulatory approach to the electric industry does not work well, and that a market-driven, customer-focused approach is essential for Bonneville's survival. Costs are being driven down by competition and new technology, giving customers more choices. Trying to dictate choices to customers is swimming against the tide. Identifying customer needs, and giving customers attractive choices about how to meet them, is the core purpose of the Marketing Plan currently under development.

Unbundling Bonneville's current products and services is the primary way we can provide these choices. Menus of unbundled products and services are being actively developed in the Marketing Plan.

Unbundling is not enough, though. Maintaining our low-cost provider position is also crucial. In past years we prided ourselves on keeping rate increases below the rate of inflation. But that is not good enough anymore. Keeping rate increases below half the

rate of inflation may be a more appropriate goal in an industry where many costs have been falling. More fundamentally, any success measurement keyed to the rate of inflation may be suspect. If we are really in a declining cost industry, relative price comparisons to other service providers--our competition--may be the only relevant yardstick.

An examination of tiered rates that would send more appropriate price signals about the cost of providing incremental services are an integral part of the Marketing Plan development. We expect the proper role for tiered rates to emerge as the Marketing Plan is developed, and in subsequent discussions with our customers and other interested parties, as we test and implement the Marketing Plan through such actions as establishing future rates and developing new power sales contracts.

Progress on the Function-by-Function Review

The Function-by-Function Review is our vehicle for seeking out opportunities for accomplishing Bonneville's work more efficiently. Each function is being examined to determine whether it can be performed with fewer staff and at lower cost. We have completed the first phase of the review, and the results are being reviewed by teams which include BPA customers and other external parties as advisors.

Progress on Internal Culture

A key part of Bonneville's competitiveness effort is to create an internal culture that supports the agency's new direction. Organizations going through fundamental change have learned that the change effort is not successful without careful attention to cultural issues. A cultural audit completed in May concluded that BPA has several strengths that will help us succeed and some weaknesses that need to be addressed. A survey of our customers confirmed many of the findings of the internal cultural audit.

Our cultural change effort is called Leadership EDGE. Through this effort, Bonneville is striving to develop excellence in managers, promote teamwork across the organization to meet business needs, and reinforce a strong customer orientation. The agency will learn to be less risk-averse and to empower employees so that they can respond faster and more effectively to customer needs. Revamping compensation and reward systems so that they reinforce this new direction is part of this effort.

Implementing the New Direction

The new direction for Bonneville will be pulled together in a Business Plan which will be shared with the public for comment before it is finalized. The Business Plan will capture the basic direction defined by the Strategic Business Objectives, Marketing Plan, Function-by-Function Review, and Leadership EDGE. The Business Plan will also include long-range plans for operationalizing this new direction in each of Bonneville's areas of responsibility.

To a large extent, where the "rubber meets the road" for the New BPA is in the new power sales contracts, the next rate case, the tiered rates process, and similar venues. We feel it is paramount that our actions in these areas be fully informed by and consistent with the new agency direction we are developing in the Competitiveness Project.

What's Ahead

This testimony is a progress report. Much remains to be done. Upcoming milestones include the submittal of Function-by-Function review recommendations to a Task Force which consists of BPA customers, Council members, and others. Our Marketing Plan will be completed this November, and the draft Business Plan will be completed next May.

Throughout the transition, there are a number of opportunities for input by Bonneville customers and others. Customer representatives and others have been directly involved in the Function-by-Function Review for the last several months. This involvement will continue. Marketing Plan conclusions will be discussed with customers and others prior to being firmed up. Public involvement opportunities will likewise be provided on the Business Plan.

Conclusion

Major changes are occurring in the electric industry, compounded by BPA-specific changes. These events make fundamental changes in Bonneville inevitable. As we initiate the necessary changes to stay competitive, we have an opportunity to expand the benefits we provide. In the process we can change the terms of the regional debate from an argument about dividing a pie of fixed-size to a collaboration on how best to expand the pie. Remaining competitive will also enable us to succeed in our continued pursuit of fish and wildlife and other non-power goals.

We have a major near-term opportunity to reduce costs and increase Bonneville's responsiveness. Our success will be key to capturing much of the benefit-expansion potential we have identified.

In our invitation to testify, the Task Force requested that we respond in more detail to some specific points. You will find our responses attached to this testimony.

We welcome this opportunity to share our progress in creating a new BPA and look forward to your input, and to sharing future progress reports.

Strategic Business Objectives
1. Achieve high and continually improving customer satisfaction. This means meeting customer needs with high value products and through responsive processes on a segment specific basis. This also means understanding how consumers value our product.
2 Expand the benefits of the power system by increasing productivity, unbundling current products and services, developing new products and services, and potentially developing new lines of business.
3. Ensure that the expanded benefits BPA creates flow to. • BPA customers through rates and through higher-value service; • the U.S. taxpayers through increased certainty of Treasury payments and reduced net federal borrowing, and • non-power goals such as fish and wildlife, by linking the pace of achievement of results to BPA's competitive success.
4. Achieve and maintain financial integrity by: • maintaining adequate economic access to capital, and • assuring fair and timely payment to creditors and the U.S. Treasury.
5. Achieve and maintain position as lowest cost power and transmission supplier at the margin and on average, for every product offered. This means BPA must be the low cost provider Strategic cost management is a permanent way of life in aggregate for the entire product line.
6. Plan, construct, and operate the power system in a safe and reliable manner in concert with other resource owners. This safe and reliable system will be achieved while maintaining BPA's competitive position within the Pacific Northwest.
7. Build competitive advantage by making environmental investments which: • produce measurable results; and • go beyond regulatory requirements wherever the competitive advantage exceeds the cost of the investment. This objective recognizes that a healthy environment and a healthy economy are closely linked in the Pacific Northwest. It also recognizes that BPA's environmental effectiveness and BPA's competitiveness are intertwined.
8. Recognized as a premiere corporate citizen of the Pacific Northwest. This means improving stakeholder understanding and confidence in BPA's decision making processes so as to better sustain BPA actions and decisions. Includes informing and involving the general public.
9. Create a business culture and organization directed toward vision & value-based leadership, customer focus, results-based performance, valuing diversity, managerial excellence and organizational effectiveness.

Questions for the Bonneville Power Administration Task Force Hearing
September 25, 1993

QUESTIONS FROM CONGRESSMAN DEFAZIO

Question 1: Why is it important for BPA to become more "competitive"? How likely is it that BPA will become a higher cost supplier of energy to the region than other providers? Are there other reasons for BPA to undertake its competitiveness initiative? What principles should guide BPA in this effort?

Answer: BPA's competitiveness is a critical issue facing the agency and the Pacific Northwest region. BPA and its customers are seeking to improve its competitiveness in a utility environment that is undergoing rapid change. If BPA fails to remain competitive, it is likely to increasingly lose customers, reduce its revenue base, and threaten the ability to repay the Federal investment in the Pacific Northwest hydroelectric system. At the same time, funding for significant environmental efforts and important components of the Pacific Northwest economy will be undermined. It is critical that BPA match the pace of changes in the industry with strategic competitive responses.

The forces that have already been unleashed, and those that are likely to occur in the future electric utility industry, are real threats to BPA being a relevant and vital player unless BPA undergoes significant change. The intensified competition in electrical generation, the emergence of viable independent power producers and brokers, new transmission legislation, the low cost of new combustion turbine generation, and the abundance of natural gas at the retail and wholesale level are a few examples of factors our customers are considering. Although BPA is not yet non-competitive

in terms of cost, some of our customers are already pursuing alternative suppliers. The perceived uncertainty of BPA's future rates, driven by escalating and unpredictable costs, and the erosion of the value from our products and services as the utility industry changes, have encouraged some customers to reduce their dependence on BPA.

BPA is uniquely positioned with a majority of the Northwest's transmission and power to continue to bring significant benefit to the region and to our customers. Our ability to remain competitive will ensure that the region's premier economic asset, the federal hydro power system, is managed--with a melding of business-like, open, and environmentally responsible principles--in a way that brings maximum benefit to the Pacific Northwest. It will enable the continued vitality of the agency in resource development, environmental issues, and achievement of planning and operational efficiencies.

BPA is currently positioned as the low cost provider to the region as a whole, although some have lower costs. With the industry changes confronting the region our advantage is narrowing, particularly for some segments of our market. Further complicating the issue is the uncertainty of our future costs, particularly in program areas such as Fish and Wildlife. Repayment reform initiatives may also result in greater costs through revised repayment schedules or higher interest rates on existing debt. Even with these uncertainties, we are committed to preserve our position as low cost provider to the markets we serve through this project. BPA must be successful with its Competitiveness Project to ensure a continued low cost power supply. Then and only then, will our customers choose to rely on

Bonneville in the new utility environment because only then will the benefits of relying on Bonneville outweigh the risks.

Both our cost and our value to our customers are important to our competitiveness. The competitiveness initiative addresses all aspects of our position in the regional supply picture, including our costs relative to other suppliers. Our ability to provide products and services that meet customer needs, delivered with efficient processes, also greatly affects their choice of us as a supplier. Our competitiveness initiative is designed to instill the internal and external changes necessary to be both the low cost and highest value supplier. Further, if BPA fails to remain a competitive supplier, the agency loses the ability to expand benefits and hence to support non-power goals such as fish and wildlife.

The principles guiding BPA's effort reflect the fundamental shift toward a more business-like enterprise while preserving the best of our governmental nature. We are focusing on internal efficiencies, effective cost management, customer choice and satisfaction, understanding of the marketplace, and achievement of results. We are reaffirming our commitment to openness and environmental stewardship as components of sound business principles. Flexibility in our offerings to customers, responsiveness to a dynamic environment, and stability in key revenue streams are also key elements of our principles. All of these are coupled with a cultural change program to obtain internal alignment with the values and objectives of our business plan. A principle of achieving maximum contribution from each employee toward organizational results is one of the underpinnings of that program.

Question 2: Should BPA adopt tiered rates? If not, why not? If so, how should these rates be structured? If there is a specific model or framework for BPA tiered rates that you support, please describe it in detail. What principles should be used in the development of these rates?

Can tiered rates be designed so that they do not discourage development of new industry in areas served by customers of BPA? Should federal base system resources be allocated through a tiered rate system?

Answer: BPA and many of its customers have become more interested in tiered rates as a means of promoting more efficient resource acquisitions by both BPA and its customers, and as a means of reducing upward pressure on BPA rates. BPA supports the concept of tiered rates, but a thorough examination of alternative tiered rate designs is needed before a final decision can be made. As part of BPA's 1993 Rate Case, BPA and the rate case parties signed a settlement on tiered rates in which we agreed to thoroughly investigate tiered rates with our customers and interested parties in an open process to be completed prior to the 1995 rate case. A tiered rate work group began this investigation in July of this year. By about July of next year, a BPA determination, based on recommendations from the work group will be made (1) for a preferred methodology or methodologies, or (2) not to proceed with tiered rates. Given the strong interest already demonstrated in tiered rates, we believe the major focus of the work group will be to determine how to design tiered rates.

At this point, BPA does not have a specific model or framework for structuring tiered rates. The Competitiveness Project is an initiative to reinvent BPA in order that the agency can move from a more traditional

government agency to one which is more business-like. A major part of the project is the Marketing Plan. This plan will provide guidance on the products and services the Agency will offer, and a strategy for pricing these products and services, including tiered rates guidance. Very early in 1994, we plan, as part of the work group process, to identify and, if possible, resolve specific tiered rate implementation and application issues for those alternatives showing the greatest likelihood of success.

The development of new industry in areas served by customers of BPA will depend in part on the retail industrial rate charged by BPA's customer. A tiered BPA wholesale rate would not necessarily lead to a tiered (or higher) retail industrial rate. The tiered rate could, however, encourage BPA's customers to make a more economically efficient decision in determining whether to promote new economic development by offering an attractive industrial rate.

Some tiered rate design alternatives being discussed by the tiered rate work group involve allocating Federal base system resources while others base the tier size on historical loads without a specific resource allocation. Both types of alternatives could potentially achieve the tiered rate objectives of promoting more efficient resource acquisition decisions by BPA and its customers. In the long run, if this objective is achieved, the region's electric rates will be more attractive to new and existing industrial consumers than would be the case if local decisions were buffered from the long-term costs of those decisions.

Question 3: BPA is considering unbundling the services it provides such as transmission, storage, load-shaping and integration services. What are the potential benefits and drawbacks of unbundling? If BPA pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some BPA services that cannot be unbundled?

Are you aware of any examples in either the public or private sectors of unbundled wholesale power services?

Answer: We first wish to provide brief background information on how BPA packages its existing services. BPA currently meets the main product needs of its customers through its utility and Direct Service Industry power sales contracts and through shorter term arrangements in the surplus power markets. The power sales contracts provide a range of service packages designed to meet the different needs of customers ranging from extremely small publicly-owned utilities to large investor-owned utilities. Each of these service packages is then sold at prices established under BPA's rate schedules. BPA also provides a variety of other services such as transmission and storage to customers based upon individual needs.

Each service package includes those services BPA and its customers negotiated based on prior contracts and requests as most valuable to a particular set of customers and excludes other services. For example, BPA's firm power service package for small customers and many DSIs includes transmission and transformation of Federal power from network voltages (generally 230 kV) to the customer's distribution voltage (generally 13.8 kV). The service package for larger utilities who generally receive Federal power deliveries at network voltages does not include this specific service. Conversely, BPA's service package for larger utilities with

substantial amounts of non-Federal generation provides for their use of the storage capability of Federal reservoirs by increasing or decreasing the amount of Federal power they purchase in any month, which is not a service BPA small utilities without resources could make use of.

BPA's service packages are designed around the premise that BPA would be the most efficient or lowest cost provider of the services in the package. A major advantage of unbundling would be to allow this premise to be tested, on a service-by-service basis, by the marketplace. Now is the proper time to do so because competitive power supply options for BPA's customers are increasing as the utility industry moves into a freer marketplace environment. Unbundling would not necessarily mean that BPA would stop providing a service, but does require BPA to identify the costs of each of the different services it provides. It would allow BPA to identify those specific services where BPA's ability to supply the service, due to changes on the Federal System or for other reasons, may be decreasing and to price those services accordingly. Identifying the cost that each service places on BPA's system would allow BPA to offer choices to its customers on whether BPA or another entity is the lowest cost or most efficient provider of this service. Greater benefits will accrue to the region where customers can expand the supply of valuable services or provide the services at lower cost or more efficiently than BPA.

Unbundling will provide other advantages to the region. In some cases, a BPA unbundled service will provide customer flexibility and value that is lost when combined and priced with other services. For example, an unbundled shaping service may be extremely valuable to customers with

generation. Offering such a service could provide such customers an incentive to use their resources more efficiently than is economically justifiable in the current bundled service environment. The customer could very well prefer the unbundled service, even if it were priced in a way that reflected its higher value and the incremental costs of providing the service. The added revenues to BPA could be used to lower prices for other services, to develop resources to support the service, to fund important fish and wildlife programs, and to assure BPA would make its payments to the Treasury, all of which would benefit the region.

Drawbacks to the concept of unbundling lie in the complexity it may create in BPA's service arrangements and the agency's ability to provide timely administration of its service arrangements with its customers. BPA customers' concerns include loss of access to low cost services, the potential that BPA might charge an excess price for valuable services only it can provide, and the ability for BPA to increase its revenue requirement without providing additional service.

BPA is currently developing a Marketing Plan that is examining what services should be unbundled, how the cost of the unbundled services would be calculated, and how the price should be determined.

BPA does not yet have answers to the questions of which services to unbundle or how these services should be priced. Some questions that might be appropriate to address include: (1) Is this a high cost-high value service? (e.g., increased loads of utilities during winter cold snaps); (2) Is this a service that requires a discreet capital investment? (e.g., distribution voltage substations); or (3) Is there a clear opportunity value for this

service in the economy energy market? (e.g., storage services.) Unbundling services on these bases might lead to expanded supply of scarce and valuable services, and customer provision of these services where they can do so more efficiently or at lower cost.

To date, BPA has not identified any services that could not be unbundled. Since most of BPA's current costs are fixed and provided from an electrically and hydraulically integrated system, identification of costs for separate services involves assigning costs to different services from a common resource. While utilities have historically engaged in this exercise in developing cost of service studies, there is no precisely right answer about such assignments.

With regards to examples of unbundled wholesale power services in either the public or private sectors, Bonneville has yet to conduct such a study. We will, however be initiating this activity in upcoming weeks.

Question 4: How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must BPA do to ensure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection of fish and wildlife?

How can the region maintain the benefits of regional coordination and planning if resource acquisition and transmission become more decentralized as a result of tiered rates and unbundling?

Answer: At this time, BPA has not made any conclusions regarding how environmental costs will be redistributed or changed from current rate-making practices in its rate structures. In our current rate design the environmental costs associated with restoring endangered fish and other species are allocated as hydro system costs to all firm power uses. How BPA allocates costs among its customers is an issue which has been historically determined in BPA rate cases.

This issue is being discussed in the Tiered Rate Work Group which includes BPA's customers and other interested parties. One proposal has been to put all of these costs in the first tier. Another proposal has been to not provide customers with a first tier allocation unless they meet certain environmental criteria.

BPA's competitive efforts will not diminish its commitments to meeting its statutory obligation to protect fish and wildlife. In fact, BPA's ability to meet these obligations hinge on its ability to remain competitive in a utility environment that is undergoing rapid change. Only if BPA is successful in becoming more competitive, which includes taking a more results-oriented approach in meeting our fish and wildlife responsibilities, will we maintain our revenue base and our ability to fund effective fish and wildlife efforts.

The benefits of regional coordination and planning will not be lost as a result of tiered rates and unbundling. To the extent that there are economic benefits from regional resource acquisition, those benefits would be reflected in BPA costs. To the extent that decentralized resource acquisition is less costly or would otherwise provide greater economic benefit, the region will benefit from such activity. A tiered power rate signal would lead to local load management and resource acquisition and operation decisions that better reflect the actual costs and benefits associated with those decisions. In the long term, this would lead to a more efficient regional power system than would be the case if local decision-making were responding only to embedded, average-cost price signals.

The same concept would apply to transmission service and pricing. By offering transmission service to customers who seek to develop their own resources, at wheeling prices that better reflect the actual cost of providing the service, BPA will be facilitating local decisions that indeed provide higher benefits than the regional resource acquisition alternative. In 1992, the Congress passed the National Energy Policy Act of 1992, based on its conclusion that benefits would derive from a more competitive marketplace in electricity. That Act directs all utilities in the United States, including BPA, to be responsive to requests for wheeling across their transmission systems.

Question 5: Should the variable rate for the Direct Service Industries (DSI) be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this variable rate.

What is the current value of reserve (VOR) of the first quartile of the DSI allocation? What is the current VOR of the second quartile?

Answer: The last VI rate review was completed in January 1991. The rate was extended until June 30, 1996. BPA has not re-examined the cost and/or benefit to regional ratepayers of extending the VI-rate beyond that period. Prior to any extension, BPA will conduct such an examination of a cost and/or benefit analysis before any decision to extend or terminate the VI rate.

Since BPA does not plan or acquire resources to serve the first quartile under the terms of the power sales contract, the first quartile offers only operating and stability reserves. The interruptibility of the DSI first quartile is recognized in the character of service adjustment, which gives the DSIs a discount for lower quality of service which they have elected to take. Therefore, no reserve value is assigned for the first quartile.

The second, third, and fourth quartiles provide capacity for both stability and forced outage reserves. This means that these quartiles can be interrupted for system irregularities so that BPA can continue to serve other loads. The second quartile provides all of the plant delay reserves, half of the forced outage reserves, and stability reserves. The third quartile provides half of the forced outage reserves and stability reserves. The fourth quartile provides stability reserves.

Based on the 1993 Documentation of the 7(b)(2) Rate Test, the total VOR for the lower three quartiles is equal to $113.9 million dollars for FY 1993. The second quartile VOR is $57.2 million dollars.

The value of reserves calculation was raised as an issue in the 1993 rate case. However, the Hearing Officer struck the issue from the case. He did so because BPA had previously established and obtained Federal Energy Regulatory Commission approval for the IP-PF Rate Link Methodology through June 30, 1996. The value of reserves credit is fixed by that methodology.

Question 6: Should the irrigation discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this discount.

Answer: The Irrigation Discount was implemented in 1985 to help irrigated agriculture in a period of economic distress. Whether BPA should eliminate the Irrigation Discount was an issue in the recently concluded 1993 rate case. The outcome of the rate case was to continue the irrigation discount for the next rate period (FY 1994 to FY 1995). The 1993 Record of Decision states the reason behind this decision.

Elimination or modification of the Irrigation Discount at this time could result in undue impacts on irrigation end-users that could be offset or avoided if changes were made within the context of a more comprehensive examination of BPA's rates. BPA will undertake a review of rate design issues, including the Irrigation Discount, prior to the 1995 rate case.

Any changes to the Irrigation Discount would not likely occur until the next general rate case. The issues surrounding the Discount will be largely influenced by the direction provided by the Marketing Plan, and by the outcome of other rate design issues such as tiered rates.

The amount of the discount (and thus the amount redistributed among the PF customers because of this discount) for the next rate period (FY 1994 - 1995) is estimated to be approximately $26 million.

Question 7: Should the low-density discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide these discounts.

Answer: The low density discount is mandated by Section 7(d)(1) of the Pacific Northwest Electric Power Planning and Conservation Act which states:

"In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers."

BPA has reviewed the low density discount every five years since it was mandated by the Pacific Northwest Electric Power Planning and Conservation Act. The last review occured in 1991 and recommeded that no modifications to the low density discount was necessary. That recommendation was incorporated into BPA's 1993 initial rates proposal.

The cost and/or benefits associated with the low density discount are included in the Priority Firm Power rate because the low density discount is merely a reallocation among the Priority Firm customers. The effect of eliminating the low density discount would be that the customers receiving the low density discount would be charged more and the customers not receiving the discount would be charged less. Excluding the residential exchange, the estimated total redistribution for FY 1994 is $22 million and for FY 1995 the estimated total redistribution is $22.3 million.

Question 8: Are there any other subsidies or discounts that BPA provides to certain customers that should be eliminated?

Answer: No, there are no other subsidies or discounts that BPA provides other than those discussed in questions 5, 6, and 7, see also question 11 which addresses BPA's Residential Exchange Program. There is also a general perception that cross-subsidization occurs among BPA's products as a result of how BPA allocates its costs. Cross-subsidization has been a recurrent issue in past BPA rate cases, including whether these and other rate issues should be eliminated. BPA's Marketing Plan may also influence the outcome of these issues.

Question 9: Should the provisions in the power sales contract which allow some utilities to be reimbursed by BPA for lost revenue when a voluntary curtailment is implemented be eliminated? If so, why? If not, why not?

Answer: As background, in 1981, Section 11(b) of the power sales contract was negotiated by BPA and its customers on the premise that a utility which voluntarily took actions to reduce its load in times of a power shortage would suffer a reduction in its revenues, and it was equitable to regionalize some of these costs. Section 11(b) provides for lost revenue payments to metered requirements and actual computed requirements customers for voluntary curtailment that is initiated by the states and BPA. There are at least four arguments why removal of these provisions might be appropriate: (1) The methodology in the current contracts is very complicated. It would be difficult to determine the amount of load reduction (to what projected load is actual load compared) and the contribution of various factors (i.e., any reduction will be the combined result of weather, economic activity fluctuations, alternate fuel availability, normal usage changes by consumers, as well as responses to the request for curtailment), to the level of precision necessary for payment purposes. (2) There is a significant workload to BPA and its customers associated with implementing these contract provisions. (3) The cost reallocation is, to some extent, circular, with the very customers to whom BPA makes the payments the same customers who, in the end, will see such payments reflected in a higher BPA revenue requirements. (4) Given the unplanned workload and the contentiousness that would be associated with these provisions, there is a reluctance to call for voluntary curtailment.

The arguments for retaining the provision center around the adverse impacts of curtailments to utilities who may not be the cause of a regional curtailment but would lose revenues if one occurred. It was this concern that caused the utilities to insist on the current provisions.

Since BPA cannot unilaterally delete these provisions from the current contracts, all customers that could receive lost revenue payments would have to agree to amend the current contracts (currently all utilities except Tacoma and the investor owned utilities).

If utilities were willing to change the current contract, BPA would be willing to consider such a modification.

Question 10: How should the long-term power contracts that BPA is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

Answer: The current contracts are based on the premise that power services can be provided most efficiently and at least cost through centralized and coordinated regional planning. The current contracts allow customers to make their own resource choices at the cost of giving up their supply of Federal power. The terms and conditions of new long term contracts will reflect the region's conclusion as to what the future business relationship between BPA and its customers should be. This relationship could include BPA offering unbundled services and pricing some services using tiered rates. Tiered rates would allow customers to choose among pursuing their own resource choices without giving up their supply of low-cost Federal power, continuing to rely on BPA provision of their resources, or choosing a combination of both strategies. As customers develop resources, each customer's need for different services from BPA will change. Unbundled services would allow BPA to respond to those needs.

What environmental issues should be addressed in BPA's long term power contracts again depends on the type of business relationship between BPA and its customers. BPA has historically asked that its customers meet the environmental standards placed on them by Congress, Federal agencies, and their respective state and local government bodies as a condition of receiving Federal power. BPA has addressed environmental issues in the choices it makes in its investments and decisions to operate the Federal system to serve its customers and reflected the costs of those environmental issues in its rates. In a more competitive electric power

market, BPA's ability to reflect environmental issues in its decisions depends on the values of its customers and the standards placed on our customers by legislation and regulation. If customers value those investments, they will be willing to pay for them. If they do not, they will seek alternatives to BPA service. Such alternatives are increasingly available as the industry moves toward decentralized resource approaches and transmission access is provided pursuant to the National Energy Policy Act of 1992.

A competitive, decentralized business relationship does offer unique opportunities in addressing environmental issues. The current system addresses environmental values on a region-wide basis and finds a common ground for compromise between communities that wish to invest for the future with a long term perspective and communities whose economies are struggling to survive in a competitive, global economy and whose focus is more short-term. A decentralized system would allow environmental values to be expressed at the community level. Local communities would make their investment decisions based on their environmental values and their ability to make long term investment decisions. Those communities able to make long term investment decisions consistent with their environmental values would not be limited by a region-wide standard.

Question 11: It has been suggested that the residential exchange program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

Answer: BPA disagrees with the suggestion that the Residential Exchange Program rewards less efficient utilities, and believes revisions to the exchange agreement are not necessary. Competitive pressures, reinforced with scrutiny by regulators, BPA, and customers under the existing review mechanism, require utilities to manage all their costs efficiently.

Competitive pressures in the energy marketplace are the primary force pushing utilities to be efficient. Utilities must recover 40 to 70 percent of their costs from commercial and industrial customers. They strive to keep their rates as low as possible to such customers because they are subject to increasing competition from other energy suppliers. Commercial and industrial rates are not affected by the Residential Exchange Program. Utilities around the region are very concerned about reducing their costs in order to compete in the marketplace, regardless of the effect of the program.

Utility costs are subject to outside scrutiny, including such considerations as efficiency and prudence, before they are filed with BPA. The Pacific Northwest Electric Power Planning and Conservation Act (Act) required BPA to develop a methodology consistent with the Act to calculate the average system cost of utilities participating in the exchange. BPA consulted with the Northwest Power Planning Council, BPA's customers, and the appropriate state regulatory bodies. The resulting Average System Cost Methodology (ASCM) was adopted as a FERC regulation, and is considered a part of all exchange agreements.

The ASCM employs what is known as the "jurisdictional approach." Under this approach, the beginning point for BPA's review of utility costs for exchange is the costs approved for recovery in rates by the state regulatory commission or, in the case of consumer-owned utilities, the local governing body. (Fully 85 percent of exchange benefits are paid to investor-owned utilities that are subject to state regulation.) During the rate case process, utilities' costs are examined in great detail by regulators or governing bodies and intervenors. Cost-effectiveness is a prime consideration. Most Northwest utilities are also required by their regulators to acquire only generation resources that are consistent with an integrated resource plan (IRP), wherein a utility selects the lowest cost supply or demand resources to meet its needs.

In addition to scrutiny in rate cases, utility costs and loads proposed for inclusion in ASC are subject to review by BPA and interested parties in the ASC review process. Under the ASCM, BPA has the right and obligation to make an *independent* determination of the appropriateness and reasonableness of all costs and loads. BPA on numerous occasions has cited such considerations as prudence and "used and useful" character to disallow costs for inclusion in ASC that had been approved by regulatory commissions or governing bodies. For example, conservation program costs not generally consistent with cost-effectiveness guidelines in the Northwest Power Planning Council's Regional Power Plan have been disallowed by BPA, as have certain administrative and general costs and power purchase costs not adequately supported by exchanging utilities.

The Residential Exchange Program's contractual agreements and review methodology were specifically crafted to comply with the Act. The ASCM provides BPA with broad legal authority to review all costs and loads for

reasonableness and appropriateness. BPA can continue to administer the program effectively without revisions to the exchange agreements or ASCM. Also, there is significant risk in initiating a reconsultation to make such revisions. BPA would be required to conduct a public process and consider input from customers and other parties. Many issues and alternative revisions would be brought forward. A reconsultation process could result in allowing additional costs to be exchanged.

Since the basic intent of the program is to provide equitable access to the benefits of BPA power for the residential and irrigation customers of all exchanging utilities, it is true that utilities with higher costs will receive higher benefits per kWh. However, competitive pressures and regulatory and BPA scrutiny ensure that costs are minimized, and that inefficiency is not rewarded.

Question 12: What part should BPA's existing resource acquisition programs play in BPA's competitiveness initiative, both during a transition period and after BPA has adopted some of the changes it is considering?

Answer: BPA has a wide variety of resource acquisition programs underway at this time. Included are current negotiations for generation options as part of the Resource Contingency Program, scheduled to be completed in 1993 or early 1994. These options provide between 650 and 1200 aMW (depending on the final negotiations and project sizes) with shortened construction lead times for use later in the decade if necessary. BPA is currently evaluating 12 billing credit proposals submitted by our public power utilities in response to an open billing credit solicitation. These resources represent almost 200 aMW of power that will be used to meet currently forecasted loads in the mid-1990s. In addition, BPA has a full spectrum of conservation development acquisitions in place that will bring on over 110 aMW in the next two years.

These resource acquisition programs are joined by demonstration projects in wind and geothermal energy that will provide the BPA system with between 45 and 100 aMW depending on the success of the projects. There are additional resources that BPA could obtain access to as a result of the geothermal projects, depending on the scope of the resources found at the various sites.

The current processes have been in operation for a number of months with projects and contracts close to completion. The resources under development provide BPA and our public power customers with considerable flexibility for a variety of possible futures. The contingency

program resources will be available should the need materialize due to increased load or decreases in the current resource base. The billing credit resources will be owned by the utility sponsors and used on their system. This will provide the utilities with more flexibility and create a different market opportunity for BPA as more utilities have acquisition choices due to their own generation.

The 1990s are developing into a competitive period when diversity and capability will aid and abet any utility system.

The future holds uncertainty about BPA's load serving obligation and the extent of those loads in a more competitive environment. A new rate structure of product line or market segmentation decision could reduce the obligations in the short or long term. Equally likely would be more uncertainty about loads as the northwest market adjusts to a new BPA. We may have no way of assessing how the region will respond for a number of years. Uncertainty remains the watch word for the region, just as it has been in recent years.

The current acquisition processes were created in an atmosphere of considerable uncertainty. Therefore, the current programs can continue into the transition period of fiscal years 1994 and 1995 without serious risk. Because we review our resource acquisition scope in detail every two years, we will complete the next review of the resource stack in mid-1994, which coincides with and supports the BPA business plan. In addition, we use 6-month check points to assure ourselves and others that our direction and scope are correct. The next check point is in the fall of 1993. It will

help us decide our need for new resources, and will determine the scope of the next billing credit review.

Conservation resource development is needed to continue the path to energy efficiency in the region. Public power utilities now have plans for developing all the cost-effective conservation in their service territories. These plans, with BPA support during the transition period of the next 2 years, provide both the utilities and BPA with a flexible future that includes high dependence on energy efficiency. The capability of the utilities to develop conservation will allow some of them to develop conservation independently of BPA or in addition to the support received from BPA.

BPA's system will be stronger with the successful completion of the current acquisition programs (as opposed to stopping now and damaging both the conservation infrastructure as well as the way the Northwest region is perceived in the power development industry). Expanding the acquisitions beyond current plans needs to wait for a more thorough assessment of the future.

Question 13: Please provide any other suggestions regarding actions that would make BPA more competitive or cost-effective.

Answer: The competitiveness initiative is quite comprehensive. There are activities being pursued or considered in all phases of BPA's internal and external business.

Bonneville Power Administration
September 9, 1993

STATEMENT OF TOM TRULOVE

Mr. TRULOVE. Thank you, Chairman DeFazio and Congressman LaRocco.

My name is Tom Trulove, and I am one of Washington's representatives to the Northwest Power Planning Council and Chair of the Council's Power Committee. With me today is Angus Duncan, an Oregon member of the Council, also a member of the Power Committee and its former Chair.

We are pleased to be here to present the Council's views on the issues that Bonneville will have to address as it faces the radical changes that may be taking place in the electric utility industry both here in the Northwest and across the country. We sent your office our written testimony which addresses your specific questions in much more detail. We thought it might be useful today if Angus presented some highlights of our testimony to you. So I will turn it over to Angus for that purpose.

Mr. DEFAZIO. Thank you.

Mr. DUNCAN. In the interest of time, Mr. Chairman, we would like to concentrate on the larger competitive utility picture we see unfolding. Our vantage point is the Northwest Power Act which you have already cited, and our mission is to develop a long-term plan for the Northwest that furthers the goals of that Act. Those goals include, most importantly, ensuring an adequate, efficient, economical and reliable power supplier for the Pacific Northwest. Economical construed in the broadest possible way to contemplate all of the costs that such a system involves. Conservation, the efficient use of energy, the development of renewable resources, protection, mitigation and enhancement of fish and wildlife in the Columbia Basin. A public accountable state role in planning the future of the Northwest power supply. Those goals remain valid for the region.

Bonneville's drive to become more competitive is just part of what is a significant restructuring in the electric utility industry, which Randy has already quite capably described. Issues like unbundling of Bonneville's products and services, tiered wholesale rates, even the value of reserves provided by the direct service industrial customers will have to be reconsidered in light of these possible changes. This restructuring could result in a regional electrical system considerably different than the one contemplated when the Northwest Power Act was passed in 1980 and the goals I just mentioned were articulated.

New technologies, deregulation and environmental concerns are changing the electric utility industry as many of those same forces changed telecommunications and the airline industry and others in the 1980s. Many observers believe this will result in more power being produced by independent developers, more pressure for access to transmission services, more marketing of individual electrical services that are currently bundled, less vertical integration within the utility industry and in general, more competition.

The challenge facing Bonneville, the utilities, their customers, regulators, the Council and Congress is not to try to stop or arrest or slow those changes taking place in the industry. That would be foolish and futile. Instead, the challenge is to achieve the goals of the Power Act, as well as the benefits of restructuring. The Coun-

cil's planning capability, we do believe, is going to be an important tool in managing that change.

There are different ways by which these futures could unfold. One scenario is a future in which the changes result in a region fragmented into a collection of individual utilities, independent power producers and others all competing to produce the cheapest kilowatt hour of electricity. There is nothing wrong with cheap electricity. Low-cost electricity has been a major benefit for the region. Maintaining those low costs is a goal for which we all strive. The concern is that in the competition to be the lowest-price producer and provider in the short run, that we not sacrifice the goal of low-cost electricity in the long run.

In this worst-case scenario, regional cooperation is sacrificed, cash flow becomes all important. Like many other U.S. industries, short-term return becomes more important than long-term investment. So research in investments in renewables or energy efficiency improvements are eliminated for investments that are less costly in the long run but can have higher near-term rate impacts. Natural gas would be the only new resource of choice. Potential benefits of greater system diversity and a regional integrated resource plan become history.

But even in this scenario, all utilities would have to rely on regional resources to a considerable extent. Bonneville would still control its widespread transmission system; although, as Randy observed, access would be available to other parties. And even in the decentralized world, the federal hydro system would continue to have substantial value. The reserves, the storage capability, the shaping services that can be provided by the federal-based system are essential to developing new resources in an economical fashion.

How should they best be employed to leverage a future consistent with the goals of the Act is one of the questions we have to contemplate. Another one—how should we treat a utility that proposes to become independent from the region? It invests in a new resource and then because of market forces or legislative changes or other effects, the power from that resource becomes uneconomical or unreliable. The customers of that utility will not be left without electricity. Instead, the regional system will have to provide the power, what costs and what risks will the region, in fact, be carrying in a world of disconnected decision making and how should the region be compensated for carrying those kinds of risks? The overall point is that these utility decisions are not made in isolation. However, some of the utilities might regard themselves as capable of making them in isolation.

We can make other choices as a region. There is an alternate scenario. The future utility world can include changes which target the goals of the Power Act and more accurately reflect the intent of the Congress while still capturing the benefits of competition. In this version of the future, we need to capitalize on Bonneville's strengths, on the hydro system and the transmission grid. Receiving the benefits of the federal-based system would carry with them some responsibility to act in the long-term interest of the region. For instance, environmental mitigation, participation in the regional integrated resource planning process and coordinated regional system.

In this scenario, all the parties—Bonneville, the utilities, independent power producers and others—would still be playing by the same rules and environmental standards. State and local governments would be obliged to do their part to enact and implement and maintain rigorous energy codes as we do now. The region would continue to cooperate both in the operation of the regional system and in carrying out those functions that need to happen at a regional level, for example, some research and demonstration activities and some conservation.

Regulatory and market conditions would be shaped to permit utilities to look at the long-term return on investment, as well as the short-term price impact of their decisions, without being placed at a near-term competitive disadvantage for doing so. Utilities would not be afraid to make major energy efficiency investments because their customer might bolt to another producer. Utilities would be able to figure out how to compete not just on price but also on service.

How we get to the latter scenario is certainly not clear to us yet, but there is reason for optimism. The Council believes Bonneville will have a major continuing role in providing electricity to the region. Unlike some of the critics today, the Council believes Bonneville is competitive now and with wise management will continue to be so. Bonneville's hydropower and transmission systems will continue to be a strategic edge for the entire region. Getting unbundling and tiered rates and other choices right, that is, in a way that serves both efficiency and equity, will be extremely difficult but doing so will also be necessary if the benefits of greater competition are to be achieved and spread to all parties in the region.

We also know that Bonneville is a large bureaucracy, and we sometimes have problems dealing with it in the same way anybody has problems dealing with bureaucracies. We believe Bonneville can improve its efficiency and its responsiveness. We believe that many of the steps that Randy has already described and that Bonneville is considering in its function-by-function review are aimed in that direction. We support that process and we are participating in it. Bonneville must become more like a business for tomorrow's utility world but we urge you also to remember that Bonneville is not just a business, it is also a federal agency. It must continue to support and act consistent with the long-term goals of the Northwest Power Act. And we are prepared and we are actively working with Bonneville, with the Administrator, in pursuit of those objectives.

Thank you, Mr. Chairman.

Mr. DEFAZIO. Thank you.

Ms. Merchant.

[The prepared statement of Mr. Trulove follows:]

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Testimony of the
Northwest Power Planning Council
before the
Bonneville Power Administration Task Force
Committee on Natural Resources
United States House of Representatives

Eugene, Oregon
September 25, 1993

Good Morning.

My name is Tom Trulove, and I am a Washington member of the Northwest Power Planning Council. With me today is Angus Duncan, an Oregon member of the Council.

We are pleased to be able to present the views of the Council on the important issues you are covering in this hearing. Many of the questions you posed address a broader issue than just the recent debate about the competitiveness of the Bonneville Power Administration. Before answering your specific questions regarding Bonneville, we would like to explore with you briefly what may be a significant restructuring in the electric utility industry, and how it might affect this region's ability to accomplish the goals set forth in the Northwest Power Act of 1980.

The Power Act envisioned a region in which most utilities would rely on Bonneville to develop new resources. In that context, Bonneville and the Council were given responsibilities to keep the region's electricity low-cost and reliable through careful long-term planning and the development of the most cost-effective and least environmentally damaging resources. The Act, as you know, emphasized public involvement in developing these plans.

As things have worked out, some of the region's utilities and industries are looking beyond Bonneville for their power supplies. This is the result of doubt about Bonneville's ability to continue to offer a competitively priced product. Competitiveness is everyone's

concern. Bonneville's focus on its competitiveness is a direct result of its customers' concern about their own ability to remain competitive.

Competitiveness is an issue now because the utility industry appears to be undergoing a major shift in relationships among the key functions of power generation, transmission, distribution and consumption. The roles of power sellers and power buyers seem less clear than they once were. How far these changes can and should go and their implications for a long-term, least-cost energy future should be the focus of major public policy debate both here in the region and nationally.

The restructuring that appears to be under way is the product of a number of forces:

- **Changing Technologies.** New generating technologies -- moderate-scale, efficient, short lead time, combined-cycle combustion turbines and cogeneration units -- are available now. Small-scale fuel cells and cost-competitive renewable resource technologies are not far behind. Some of these technologies are utility scale. Some, however, are small enough to be appropriate for large industrial or commercial consumers. These technologies and, as importantly, low-cost natural gas, are rapidly changing our expectations about *how* we will generate electricity, *who* will generate it, *how* it is marketed and delivered, and *from whom* consumers will purchase it.

In addition. new technology in transmission and distribution can improve efficiency, ease access to transmission and potentially increase the competitive advantage of those who control transmission services.

Technology is also creating dramatic changes on the consumers' side of the meter. One of the fundamental concepts of the Power Act was to view more efficient structures and equipment as electricity resources. In the future, new communication and control technologies could provide consumers with instantaneous information on their electricity rates and the ability to adjust their electricity use accordingly. Such technologies could also enable utilities to control the operation of appliances or equipment in homes and businesses to reduce demands on generation and distribution. These technologies could fundamentally alter the relationship between the utility and its customers.

We should neither be stampeded by the technological changes taking place nor ignore them. It is clear, however, that if technologies emerge that confer a competitive advantage in the marketplace, markets and regulations will tend to evolve to accommodate them.

- **Regulation or, more accurately, deregulation.** Beginning with the Public Utilities Regulatory Policy Act (PURPA), there has been a trend toward easing entry into the business of generating electricity. PURPA was intended to encourage cogeneration and small renewable generation by requiring utilities to purchase power from qualifying

independent power producers. The National Energy Policy Act of 1992 (EPAct) continued this trend both by creating a class of "exempt wholesale generators," power producers that are exempt from the provisions of the Public Utility Holding Company Act (PUHCA), and by opening access to transmission for wholesale power transactions. While Bonneville also has to provide access, it was granted the right to condition that access so that it does not impede its ability to satisfy its other mandates, such as those contained in the Northwest Power Act.

While there are many difficult issues to be resolved in implementing the provisions of EPAct, most observers conclude that EPAct will result in more power being produced by independent developers, more pressure for access to transmission services by new producers, more marketing of individual electrical services that are currently "bundled," less vertical integration within the electric utility industry and, in general, more competition.

Taken to the extreme, open transmission access could lead to "retail wheeling" -- a requirement that utilities distribute to their retail customers power produced by non-utility suppliers or even other utilities. Under such conditions, customers may have their choice of suppliers of electricity without having to move out of their current utility's service territory. While EPAct did not require such transactions, it did underline the fact that the states have responsibility for deciding this issue. Since the EPAct was signed, retail wheeling legislation has been introduced in some states, although none have yet enacted it.

Retail wheeling or even the expectation of it poses some significant problems. Some utilities that believe retail wheeling is coming may be reluctant to make the investment in long term, least-cost, but capital intensive resources like conservation and renewables. While some of these resources are less costly in the long run, they may have a slightly greater near-term impact on rates -- one very narrow measure of competitiveness. Utilities also fear these resources will become "stranded investments," i.e., some of the customers the resources were planned to serve may turn to other electricity suppliers, leaving the remaining customers to pay for the resources. Customers who cannot take advantage of retail wheeling or self generation will end up paying higher rates to cover the costs of such investments. While it is tempting to believe that state regulators can "just say no" to retail wheeling, that may not be possible. If there is a competitive advantage to be achieved through retail wheeling, the pressures to allow it will become intense.

- **Societal expectations.** Society also has new expectations of the utility industry. These include the expectation that utilities should be held accountable for environmental damages resulting from power generation, transmission and related activities. Such accounting may be retroactive, as in the Northwest's experience, where utilities are now having to contribute to the recovery of salmon runs that were damaged, in part, by hydroelectric dams built years ago. There is also a trend toward holding utilities accountable for potential impacts of future resource development. These are legitimate societal aims.

However, any costs incurred because of such expectations should be applied equitably to all the players: Bonneville, the public and private utilities, and independent power developers. Otherwise, utilities and others meeting those expectations could be at a price disadvantage compared with developers that can avoid those requirements. The net effect would be that responsible developers would be less competitive and environmental goals would not be achieved.

Virtually all utilities are contending with these forces. Bonneville, however, has additional challenges that have led some of its customers to question the agency's ability to compete with other power suppliers. These challenges include: potential rate impacts from repayment reform; additional costs attributable to fish and wildlife recovery measures; and the very size of its own bureaucracy -- a particular burden in a time when it is necessary to be fast on one's feet. Whether Bonneville's customers are correct in their concerns matters less than whether they are acting on them.

Implications for the Goals of the Power Act

How Bonneville, its public utility customers, the investor-owned utilities and consumers of electricity react to the forces that appear to be driving the restructuring of the industry will have much to say about how successful the region will be in meeting the goals of the Power Act. These goals include:

- conservation and efficiency in the use of electric power;
- the development of renewable resources;
- assurance to the Northwest of an adequate, efficient, economical and reliable power supply;
- protection, mitigation and enhancement of the fish and wildlife of the Columbia and its tributaries; and
- a publicly accountable state role in planning the future of the Northwest's power system.

In a Pacific Northwest that may be quite different from the one envisioned in the Power Act, we are still seeking the best and most efficient means of achieving those goals. We believe we must look at all elements of the electric power industry -- power producers, marketers and users -- to better understand and help shape that industry's future, guiding it toward the goals of the Power Act.

The lesson from most other industries that have undergone restructuring is that competition generally leads to lower prices. That is clearly a benefit for consumers. But competition does not always lead to better value, reliability, equity, or fulfillment of broader societal responsibilities. In the airline industry, for example, fares have declined on average.

Quality of service, however, has also declined in the eyes of most, and, for many, fares have gone up.

It is not yet clear how Bonneville and other utilities will respond to restructuring forces. One model of competition suggests that electricity is fundamentally a commodity, and competition will ultimately be on the basis of price alone. If that is the model that characterizes the Northwest utility response to competitive pressures, it bodes ill for the goals of the Power Act. The fundamental issue is that utility concerns about stranded investment and short-term price competition discourage investment in the long term least-cost future envisioned by the Power Act. The lowest price does not necessarily ensure that the product is the best value for society.

There are, however, other ways in which Bonneville and the region's utilities can choose to be competitive. If they choose to compete on the basis of delivering the best value for the dollar -- the lowest energy *cost* to satisfy an end use as opposed to the lowest electricity *price*, the goals of the Act stand a much better chance of being achieved. The utilities' growing expertise in demand-side management and the promise of new control technologies that will permit utilities to provide their customers with more choices and greater value gives them a new area of potential competitive advantage. The key is the concept of "value," which does embrace the long-term societal goals of the Power Act.

The challenge facing Bonneville, the utilities, their customers, state regulators, the Council and Congress is not to stop the changes taking place in this industry. That would be futile. It is, instead, to try to guide or manage that change so the region achieves both the benefits that these changes can bring and the broader goals embodied in the Power Act. The Council's planning process and its plan can be important tools for managing that change.

The Council is analyzing the forces of change in this industry and seeking opportunities to guide that change. At our August meeting, we participated in a spirited debate with proponents of different models of utility restructuring. Our staff is preparing an issue paper that will critically examine the forces affecting the structure of the industry; the consequences of not being competitive at both the wholesale and retail levels; and the available policy alternatives. We are consulting with knowledgeable persons both inside and outside the region. We are participating in Bonneville's function-by-function review, which is one facet of the agency's competitiveness project, and we are working with Bonneville to help streamline the delivery of conservation services. We will keep this committee informed as our work progresses.

Bonneville's Competitiveness Project

In response to your question regarding Bonneville's competitiveness project, let me first say that the Council believes Bonneville is now, and can continue to be, a competitively

priced wholesale power provider. Council staff compared the cost of power from new resources with forecasts of Bonneville's wholesale rates under the current flat rate structure. Using our mid-range growth projections, purchasing power from Bonneville will cost utilities less than building and operating their own resources. Only under "worst case" assumptions of unexpected costs to Bonneville, including fish and wildlife costs and continued low gas prices, is Bonneville in danger of losing its price advantage.

It is also important to remember that Bonneville's rates cover a great deal more than just the cost of energy at the busbar. With that single rate, Bonneville's customers receive reserves, transmission, load shaping and, importantly, risk sharing. These are services that would cost them extra were these customers to buy them from an independent power producer.

It may, however, take more than low power prices for Bonneville to be competitive in the future. As we indicated earlier, adding value on the customer's side of the meter should be a significant part of a competitive utility's repertoire. The experience of Bonneville and its customers in developing conservation should give them a competitive edge. And Bonneville has a clear competitive advantage as a broker of transmission services. However, conditions under which Bonneville would not be competitive are possible. Bonneville's competitiveness project is an entirely appropriate effort to identify how the agency should restructure itself to respond to the forces affecting the industry as a whole.

We think Bonneville is looking at the right things. Through the function-by-function review, it is examining how it can better manage costs. In its marketing plan, Bonneville is trying to better understand its customers and their needs. It is trying to define a mix of products and services to meet those customer needs. If that is what Bonneville means by being more like a business, the Council is supportive.

Bonneville must remember, however, that it is not *just* a business. As we noted above, utilities can choose to respond to the competitive challenge in ways that facilitate achieving the goals of the Power Act or in ways that do not. The goals of the Power Act address more than short-term prices. The choices Bonneville makes in its competitiveness project must support not only its need to be competitive but also its broader responsibilities. Up to this point, we would have to say that Bonneville's marketing analysis has not been open to review and input from the Council and others. We understand that will change in the near future. We look forward to working with Bonneville on the important policy issues embedded in their market analysis.

Unbundling Services

Bonneville's current service to its public utility customers bundles a lot of "products" together and charges one rate for them. These products include not only energy, but also

capacity, transmission services, load shaping, reserves and so on. These products are delivered at a single, so-called "postage stamp rate" -- the same price regardless of the actual cost to deliver the service to different locations under different conditions. This pricing structure was one of the cornerstones on which Bonneville was founded.

Many Bonneville customers are going to want and need to continue to receive that bundled service. Other customers may find that to respond to their own competitive challenges they want to develop some of their own resources. To do so, they will need some of Bonneville's services but not others. They may want to purchase storage or transmission or reserves, or some combination of products. If utilities can develop resources that are consistent with the Act and the Council's plan and do so more cost-effectively than Bonneville, then Bonneville should be able to provide the services necessary to facilitate that development. The challenge to Bonneville will be to market those services, whether bundled or unbundled, at fair prices that reflect true costs, don't give advantages to one group of customers at the cost of another, and do not impede Bonneville's and the region's abilities to fulfill the broader responsibilities found in the Act. The Council supports Bonneville's providing unbundled products and services if it can be done in ways that satisfy those criteria.

Marketing unbundled services in such a way that these criteria are satisfied will, however, be an extremely difficult and potentially contentious task. For example, which and how much of these services are subject to public agency preference? Unbundling also interacts with and complicates other initiatives such as tiered rates. Nevertheless, unbundling can be done. Bonneville currently offers some discrete services like transmission and capacity. Other utilities routinely offer unbundled products. Working these issues out will be a major focus of the renegotiation of Bonneville's long-term power sales contracts.

Tiered Rates

Tiered wholesale rates provide a base amount of power at one price and charge a higher price for power above that base amount. There are many ways in which a tiered rate structure could be designed. In general, the first tier would reflect the amount and cost of power from the federal base system while the second tier rate would reflect the cost of power from new resources. This does not, however, necessarily imply strictly linking the tiers to specific resource pools.

In general, environmental costs attributable to specific resources should be allocated to the tier to which those resources are allocated. Fish and wildlife costs attributable to the federal base system should be allocated to the first tier. Environmental costs associated with new resources should be allocated to the tier or tiers to which the resources are allocated. However, as noted earlier, if only Bonneville must take environmental costs into account, the

effect will be to encourage independent development of less environmentally sound resources. Care must be taken to maintain a level playing field.

For the Council, the objective of a tiered wholesale rate structure would be to provide a rate signal that would encourage utilities to undertake conservation and other resource development on their own where they can do so more cost-effectively than Bonneville. The Council has supported the concept of tiered wholesale rates for some time. The 1991 Power Plan specifically asks Bonneville to implement tiered rates if billing credits and Bonneville programs are not sufficient to achieve the plan's conservation targets. While Bonneville appears to be on track with the conservation targets, billing credits have not figured significantly in achieving those targets.

The logic of providing a marginal price signal to encourage utility development of new resources, particularly conservation, remains attractive. A reliable tiered rate would minimize most utility concerns about lost revenues from conservation. Individual utilities or utility consortia, such as Washington's CARES, can borrow money at a lower cost than Bonneville. And, there is reason to believe that at least some efficiency improvements can be secured more efficiently by utilities than through Bonneville programs. Some believe that a tiered rate structure would be an incentive to Bonneville to be more efficient in its resource development.

However, depending on how they are designed, tiered rates could result in a very different allocation of the costs and risks of new resource development than is currently the case. In today's Bonneville system, for example, resource development costs and risks are spread throughout the region, even to those who are not growing. If , however, tiered rates are designed based solely on an allocation of the federal base system that is not adjusted to reflect load growth, utilities that require new resources will be faced with the full cost of those resources, whether they acquire them on their own or from Bonneville at the upper tier rate, while those who are not growing will see no rate impact. If utilities develop the resource themselves, they bear the risks but also stand to get the rewards of good management. The growing utilities are not limited to one type or area. They are both big and small. Many are located in the I-5 corridor, but many are also located in other parts of the region.

There are, however, other ways to design a tiered rate that would lead to a somewhat different allocation of costs and benefits. If, for example, the size of the first tier is allowed to grow in some proportion to a utility's growth, the effect will be to put the costs of some new resources in the first tier, causing the first tier rate to rise. This will result in some degree of sharing of the costs of new resource development around the region at the expense of diluting the economic signal for resource development.

These trade-offs need to be thoroughly explored as the region examines the tiered rate concept. Depending on the circumstances of a utility, a tiered rate design or, for that matter, the current flat rate design, may be considered equitable by one and inequitable by another. The Council is participating in Bonneville's process to develop a tiered rate. Our objective in that process is a tiered rate structure or some other mechanism that is as equitable as possible to all and that provides a clear signal for the development of efficient resources consistent with the Act and the Council's plan.

Although tiered rates will provide an incentive for utility resource development, the Council believes there will still be a need for Bonneville to be an effective resource provider. There will still be many utilities that will have to rely on Bonneville programs for conservation and new generating resources. Moreover, there are some activities that really need to take place at a regional level. These include facilitating utility consortia to develop conservation in chains and franchises; market transformation activities such as manufacturer incentives for efficient equipment and products; and provision of support activities and research, development and demonstration that will be essential if Bonneville's customers are going to continue to be competitive.

The Value of Reserves Provided by the Direct Service Industries

The regional power system needs reserve power so that it can meet loads under adverse conditions. Typically, reserves have been thought of in terms of energy to meet needs under low water conditions or in the event of outage of generating plants. More recently, as the hydroelectric system has become more constrained, concerns have also arisen about the capacity of the system to meet peak loads and the need for peak reserves. The direct service industries have provided reserves through the ability to restrict portions of their load under certain conditions.

The questions the region must now confront are how much and what kind of reserves does the region need, what is the value of those reserves, and what is the most efficient way to provide them? It has been some time since these questions have been examined. They should be answered in the context of the power sales contracts renegotiations. A technical group has been formed to analyze these questions. Council staff is participating in that group. When the work group has completed its work, there will be important policy decisions to be made.

Obviously, discussion of the value of reserves and how they are best provided cannot be divorced from the question of the future of the aluminum industry in the region. Choices could be made that some contend would result in the immediate shut-down of the industry. This would have adverse impacts for industry and the power system. At the other extreme, however, trying to perpetuate the status quo may be both expensive and futile in the long run. The aluminum industry will undoubtedly be affected by forces outside the control of this

region. The Council believes that the guiding principle should be that the cost of the reserves to the region should reflect their value as closely as possible, whether those reserves are provided by the direct service industries or through other means. We believe there may be creative options that serve the interests of the aluminum industry and the region as a whole.

Power Sales Contracts

The power sales contracts renegotiations are where many of the issues discussed above will be confronted. The power sales contracts will define the terms and conditions of transactions between Bonneville and its customers for many years to come. This process is critical to the region.

The Council is participating in the power sales contracts process, although we are not a party to the contracts. The Council's goal in participating is to see that, at a minimum, the new contracts do not impede achieving the goals of the Power Act, the Council's plan, and the fish and wildlife program. More affirmatively, the power sales contracts could enhance achievement of the goals of the Act and the plan, particularly as the region and the utility industry more generally enter what may be a new era.

As noted in our opening, the changes going on in the utility industry portend a regional electrical system considerably different than the one contemplated when the Power Act was passed. The investor-owned utilities have never turned to Bonneville for new resource acquisition. Clearly, if changes like tiered rates, unbundling of products and services, and wholesale transmission access come to pass, Bonneville quite probably will not be acquiring new resources for some of its public agency customers, let alone for the investor-owned utilities. The effect of these changes will be to provide individual utilities the opportunity for greater autonomy in the development of resources, should they choose to exercise it.

However, the fact that the structure of the utility industry in the Northwest may be different than the assumptions underlying the Power Act does not mean that the goals of the Act are invalid. The goal of an adequate, efficient, economical and reliable power supply, utilizing long-term, least-cost, environmentally sound resources is still valid. The goal of protection, mitigation and enhancement of the fish and wildlife of the Columbia and its tributaries is still valid. The independent check on the need for power provided by the Council's plan is still appropriate. And the goal of publicly accountable planning and decision-making is also still valid.

Greater autonomy in the development of new resources must not imply freedom from regional responsibility. No utilities are proposing forsaking their access to the federal base system. The federal base system will continue to be a resource of tremendous value to the region. It will be the services provided by that system -- transmission, storage, reserves,

shaping and so on -- that make greater autonomy in new resource development possible. Obtaining those services implies a responsibility for supporting a regional system that is consistent with the goals of the Power Act. In light of the changes that are under way in the region, the issue with which the Council is wrestling is this: for those utilities that will be exercising greater autonomy in the development of new resources, is there a need to reinforce their responsibility to help achieve regional goals that are affected by that development, and are the power sales contracts the appropriate mechanism for accomplishing that reinforcement? If so, how would it be accomplished? If not, how can the region be assured that its goals will be pursued in the evolving, restructured, more competitive utility system?

Some parties to the power sales contracts have argued that the contracts should be restricted to only those terms and conditions directly related to the power sale transaction. The existence of the Council's plan as a benchmark against which the resource acquisition plans of individual utilities could be judged might be sufficient guidance. Other parties have argued that the power sales contracts should include the responsibility to participate in the implementation of the goals of the Power Act as reflected in the Council's plan. The Council has not yet reached a decision on this issue.

Other Issues

Your letter raised several other issues on which the Council has not taken positions. We do, however, offer the following observations:

Direct Service Industry Variable Rate and the Irrigation Discount

Both the direct service industry variable rate and the irrigation discount were instituted at a time when they were likely to be a "win-win" for the region. The utility system had a large surplus. The aluminum industry and agriculture were both depressed, with low prices on world markets. These rate mechanisms were a means by which the utility could make a sale it might not otherwise make, and the industries could afford to operate and be competitive. To the extent these arrangements still constitute a win-win for the region, they should be retained. However, circumstances in the utility system and international markets have changed since the inception of these rates. They should, therefore, be re-examined in light of the changed circumstances.

Low-Density Discount

The low-density discount was specifically authorized in the Power Act in recognition of the significantly higher distribution costs experienced by some of the rural utilities in the region. The Council recently met in rural western Montana. The utility serving that region serves an average of two and one-half meters per mile of distribution system, far less than the

average of a more typical urban utility. Congress decided that the region as a whole could bear some of those increased costs experienced by very rural utilities. The magnitude of the discount is small, amounting to only $22 million per year.

The Residential Exchange

The residential exchange was part of the "deal" of the Power Act by which the residential and small farm customers of the region's investor-owned utilities were ensured a share of the benefits of the federal system. The investor-owned utilities and some public utilities exchange power for their residential and small farm customers at their average system cost and receive the same amount of power at Bonneville's average system cost.

Some parties have raised the possibility of abuse of this system by an exchanging utility overstating its average system cost. However, the costs of the investor-owned utilities are overseen by state regulators who have a clear responsibility to see that a utility is not overstating its costs. Bonneville itself closely examines those costs. The Council has seen no evidence that there has been abuse of that system.

Mr. Chairman, that concludes my testimony today. On behalf of the Northwest Power Planning Council, I want to thank you again for the opportunity to present the Council's views. The Council looks forward to continuing to work with your committee in the months ahead.

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STATEMENT OF JUDITH MERCHANT

Ms. MERCHANT. Good morning, my name is Judith Merchant, and I am the Director of the Washington State Energy Office. I am very pleased to be here this morning to present the views of the executive agencies of the State of Washington on the issues of your hearing. We are very grateful to you, Mr. Chairman, and you too Representative LaRocco, for conducting these hearings because we think that the questions you have raised foreshadow the broad issues of the future of the Bonneville Power Administration and the fate of the Power Act. We share your concerns and commitment to it, and the economic, social and environmental values that are embodied in that legislation.

We very much value Bonneville as a partner in creating an environmentally and economically sound energy future for the State and the region. We are very supportive of Administrator Randy Hardy in his efforts to streamline Bonneville's services and reduce cost. We have an enormous stake in the future of Bonneville. We are very sensitive to the future because our State represents 65 percent of Bonneville's sales and many of our utilities, industries and consumers rely on Bonneville for affordable power.

We have detailed our views in our written testimony, and I would like to focus on three basic policy issues. First and foremost is that we support the Pacific Northwest Power Act which sets out an ambitious agenda of cost-effective conservation and renewable resource development, power planning, fish and wildlife, goals which have been discussed. Bonneville plays an essential role in carrying out the provisions of the Act. It brings a scale and a reach that is needed to ensure that the Act provisions can be carried out. Let me give you an intangible example. The Washington State Building Code Council has just passed commercial energy codes. This would not have been possible if Bonneville and other utilities had not been there to say, yes, we will support the implementation and enforcement codes. It played even a stronger role in the passage of the residential energy codes. This commercial code, for example, will save 200 average megawatts of energy. That is a considerable resource to this region.

Bonneville is very important to us as a resource in assisting in procedures for siting new energy resources. Whatever changes occur in the market, Bonneville's ability and commitment to participate in regional conservation and resource development activities is essential.

Second, we do believe that Bonneville is and will remain a very competitive provider of electricity and power services. We also believe that enhancing competitive forces can help us achieve our policy goals, but only if they are used very carefully and very appropriately. Market forces such as tiered rates and unbundling can help Bonneville convey the higher long-term cost of new power resource and the value of efficiency improvements. It is important to ensure that these market forces are not used to frustrate the goals of the Power Act by allowing low-cost providers to circumvent them. Therefore, we would encourage Bonneville to consider the following principles in establishing tiered rates.

First, regional obligations should be paid for by all of us. No customer should be allowed to avoid the fish and wildlife obligations

associated with the federal system or other explicit requirements provided for in the Act.

Second, if we use higher marginal prices to send a price signal, we should ensure that all users see the signals, otherwise the incentive for efficiency will be diluted. This means a very careful structure of what is included in each tier the second tier needs to be broad enough to send clear signals.

Third, we should be sure that, in using tiered rates to send this stronger marginal price signal, that we do no set it so high that it triggers excessive construction of new gas generation or abandonment of regional conservation programs.

We must also remember that market pricing itself is not a substitute for conservation programs. The conservation market is very complex and there are many reasons for market failures. Higher prices by themselves do not solve these marketplace problems. To meet our conservation goals, customers must see both a price incentive to conserve, but also have access to effective conservation programs.

The notion of unbundling Bonneville's service can add considerable complexity to tiered-rate issues, but unbundling, we feel, is essential to make tiered rates successful as a competitive tool. Bonneville could unbundle a significant number of services, including transmission shaping, capacity, interconnection, fish and wildlife programs and conservation programs by sector. The more Bonneville unbundles these programs and charges for these services, the less it needs to charge for raw electricity. This clearly could magnify Bonneville's competitive advantage as a commodity supplier. But it also creates potential problems in ensuring compliance with regional priorities, especially for conservation and instability and revenues to support Bonneville programs.

Our third and final point is that uncertainty costs us all. We believe that market forces have not fundamentally changed either the benefits of regional coordination and planning or the regional value or the resource priorities of the power plans. Whether tiered rates and unbundling help us achieve these regional goals will depend on large measure on how they are structured and implemented. It is very possible to envision tiered-rate proposals that strongly support regional priorities while allowing the benefits of competition to emerge. It is also possible to envision proposals that destabilize Bonneville much in the same way that Angus Duncan has described and erode our ability to meet Power Act goals. We need a specific proposal from Bonneville to allow all parties to begin to analyze the true probable effect of tiered rates and unbundling. We encourage them to provide this information as soon as possible. We are concerned that speculation over the future of Bonneville products and services could lead to uncoordinated investments in new gas-fired generation or in the failure to acquire conservation resources. Either result would lead us away from the least-cost energy path envisioned by the Power Act.

In summary, we would like to reiterate our support for Bonneville's continuing efforts to improve efficiency and to streamline delivery of products and services. We have much to gain as a State and a region in those efforts. We believe that Bonneville is and will remain a competitive provider, and we will work with your commit-

tee and with Bonneville to ensure that we attain our regional goals.

Thank you very much, Mr. Chairman.

[Prepared statement of Ms. Merchant follows:]

Testimony of the State of Washington
before the
Bonneville Power Administration Task Force
Committee on Natural Resources
United States House of Representatives

Eugene, Oregon

September 25, 1993

Good morning. My name is Judith Merchant, and I am Director of the Washington State Energy Office. I am pleased to have this opportunity to present the views of the executive agencies of the state of Washington on the issues addressed by this hearing. The specific questions asked by the Committee foreshadow broad issues about the future of the Bonneville Power Administration (BPA), the fate of the 1980 Pacific Northwest Electric Power Planning and Conservation Act (PL96-501) (Power Act), and the economic, social, and environmental values embodied in that legislation.

In examining the range of issues before us, from rate restructuring to BPA's competitiveness project, we have asked ourselves a relatively simple question: which of these approaches are most consistent with our need for fairly priced, reliable, equitably distributed, environmentally sound power? Out of that question, we have reached five basic conclusions:

- First, we strongly support the principles of the Pacific Northwest Electric Power Planning and Conservation Act calling for cost-effective energy conservation and renewable resource development; a comprehensive and open process of power and fish and wildlife planning; coordinated electricity resource acquisition by BPA; and investments by BPA to achieve the objectives of the fish and wildlife plan.

- Second, we support BPA's efforts to streamline many of their processes and reduce costs. The power market is changing and the pace of change will accelerate. BPA's efforts to become more efficient can benefit us all.

- Third, we believe BPA is and will remain a very competitive provider of electricity and power services. Some of this strength will come from decisions we make; some is inherent in the value of a hydroelectric system.

- Fourth, tiered rates and unbundled services can help achieve the goals of the Power Act. However, there remain many issues to be articulated and resolved in moving from the concept of tiered rates and unbundled services to a workable, widely supported proposal. In particular, rate restructuring must work with efficient programs to achieve conservation and fish and wildlife goals.

- Finally, uncertainty costs us all. BPA needs to develop clear proposals on tiered rates and unbundling soon, so that all parties are dealing with real numbers, rather than their imagined best or worst case scenarios. As BPA moves forward, we pledge to work closely with the agency to implement proposals that improve administrative efficiency and help achieve the goals of the Power Act.

Background

The 1980 Power Act envisioned BPA playing the dominant role for the Pacific Northwest in developing new cost-effective energy efficiency and high priority generating resources. The Northwest Power Planning Council (NWPPC) was established to direct and oversee this resource development to improve conditions for fish and wildlife and ensure least-cost electric power services. Since the enactment of the 1980 Power Act, there have been profound changes in the electric and gas utility industries. With implementation of the Public Utility Regulatory Policies

Act (PURPA), deregulation of the natural gas industry, repeal of the Power Plant and Industrial Fuel Use Act, passage of the National Energy Policy Act (1992), and inexpensive and abundant natural gas, utilities and large industries have begun to look beyond BPA to other sources including independent power generation projects to meet their growing power demands. With the need for salmon protection, the potential for accelerated federal debt repayment, and requirements for increased transmission access, some industries and utilities doubt that BPA can remain a low cost provider of basic power services.

Competition is keener in today's electric power industry. Because of extremely low natural gas prices, technological improvements in gas turbine design, and federal regulatory changes dating from the late 1970s, the market for new generation is increasingly dominated by independent, non-utility power producers. This is likely to continue so long as natural gas power plants have low capital cost, are perceived to be low risk, and are easy to site. As a result, utilities with high retail rates driven by excess capacity in transmission, distribution, and expensive coal and nuclear plants are put in the most severe competitive disadvantage. It puts systems with relatively low retail rates and fully utilized transmission and generation in strong positions.

Moreover, this increased competition can lead to a fundamental disconnect between our planning process and our ability to implement those plans. The unique nature of our hydro system has led us to develop the most elaborate planning models in the world to ensure that the benefits of the system are maximized and that new resources have the lowest long term costs and environmental consequences. But if decentralization in the market presents an obstacle to implementing those plans, how do we retain the advantages of long range planning and a fast acting marketplace?

1. ***Why is it important for BPA to become more "competitive?" How likely is it that BPA will become a higher cost supplier of energy to the region than other providers? Are there other reasons for BPA to undertake its competitiveness initiative? What principles should guide BPA in this effort?***

In our estimation, BPA is an extremely competitive provider of a complete range of electricity services. Because of the hydro base, the Pacific Northwest electricity system produces the cheapest bulk wholesale and retail electricity in the nation, much of it at near zero marginal operating cost. BPA's 27 mills/kWh average rate is well below the 38 mills/kWh (1993$) cost of new generation from the Tenaska II project. However, the very early year costs of Tenaska II are quite close to BPA's average rate and could have smaller near term rate impacts than many lower lifecycle cost conservation investments. This suggests a competitiveness problem. But the long term cost of producing power from new generation and adding the transmission and distribution to deliver it is greater than embedded costs.

Bonneville's basic rate for wholesale power includes a wide range of power services including shaping, reserves, transmission, and capacity elements. These services are necessary to turn raw electricity generation into a useful and reliable product. The costs for these important services are not reflected in the basic cost of electricity to be generated by the Tenaska II project. When we assess the competitiveness of BPA's wholesale power prices we need to consider not only the raw cost of new electric generation, but the cost of related power services necessary to turn electricity generation into a product that is useful and reliable. Because of the sheer size of the federal power system, the storage capacity of the hydroelectric projects, and the extent of the federal transmission system, BPA is better positioned than anyone else to provide the non-power services that permit raw electricity to be provided as a market product.

There is also risk associated with the development of new electricity resources. Natural gas prices are currently very inexpensive, but fuel supply contracts have been known to be broken. BPA acting as a central developer and marketer is better positioned than individual utilities to diversify that risk over many projects. In addition, as the central marketer of power in the Northwest, BPA is able to ensure that new electricity generation does not lead to excessive transmission investments. Finally, BPA is the dominant marketer of surplus energy and capacity from the Northwest, and is better able to sell or re-package valuable services to utilities outside the region.

Finally, we feel strongly that BPA must focus on the cost of its operations to become a more efficient purchaser of electricity resources, fish and wildlife programs, and electricity conservation. We strongly support these efforts. We do not believe that BPA should avoid a central role in fish and wildlife program support, generation acquisition, regional conservation programs, and in maintaining a strong regional economy. We do believe that substantial improvements can be made in the efficiency with which it does business.

2. ***Should BPA adopt Tiered Rates? If not, why not? If so, how should these rates be structured? If there is a specific model or framework for BPA tiered rates that you support, please describe it in detail. What principles should be used in the development of these rates?***

In general, WSEO supports stronger price signals to ensure that all BPA customers see the higher cost of new electric power resources. An equitable approach to tiered rates can help create an environment where all BPA customers benefit from energy efficiency improvements and cost-effective resource additions. However, the implementation of equitable tiered rates is far from a simple matter.

It is possible to envision a variety of approaches to tiered rates that are potentially consistent with the Act. For example, one could allocate the federal base system (FBS) to the first tier and new resources to the second tier. This would mean a first tier below 27 mills/kWh and a second tier above that level. Revenues from first tier sales would cover the costs, including debt repayment for the existing FBS, environmental impacts caused by the FBS, and any explicit statutory requirements of the Power Act (for example, regional conservation research and development and the low density discount). Revenues from the second tier would support the development of new resources, any non-power services made necessary (like transmission upgrades), and any environmental costs imposed by the new electricity resources.

In developing a tiered rates proposal, we encourage BPA to follow these principles:

1. Equity and Regional Obligations

   First, tiered rates should not allow some classes of customers to escape regional obligations. *All* customers should face some marginal price signal that provides an incentive to improve efficiency, provide access to cost-effective fuel choice, and support required fish and wildlife programs. Customers should not be able to avoid paying for statutorily required efforts, including any explicit subsidies -- such as the low density discount. We understand that this could raise first tier costs and dampen the price signal of the second tier.

2. Revenues for Necessary Regional Programs

   Tiered rates should be designed - at least in the near term - to ensure BPA maintains sufficient revenues to support new generation, transmission, and conservation programs. Consider a second tier set at full marginal cost -- for example, the cost of Tenaska II, associated transmission, and external costs. Without some ability to ensure stable revenues from this tier, BPA could find it very difficult to plan for resource development

programs (demand or supply side), and would certainly find it difficult to run programs with high fixed costs, such as conservation efforts. Even for generation resources, BPA's revenues and programs could become questionable.

High second tier rates will not necessarily lead to long term least cost results. For example, utilities concerned about short term rate impacts from rate restructuring might also prefer generation contracts with low first year costs to the near term rate impacts of efficiency improvements that have lower long term cost. Utilities concerned about their own revenue instability might retain existing retail rates even with tiered wholesale rates. A complete tiered rates proposal needs to account for these possible unintended consequences.

Setting the second tier at full marginal cost could also pose a problem of scale. Tenaska II is a small resource (about 200 MWa) in a 8800 MWa federal system. Basing the second tier on this resource alone would send only a small price signal to a limited number of customers. To improve revenue stability, we believe BPA could meld some amount of recent resource acquisitions, including exchanges and new generation, into a less expensive and physically larger second block.

3. Past Conservation Activities Should be Recognized

The implementation of tiered rates should not penalize utilities that have had significant population growth or aggressive conservation programs throughout the 1980s. This might argue for setting a first tier allocation based on early 1980 per-capita consumption.

4. Tiered Rates Cannot Completely Replace Coordinated Programs

Finally, while there is value in sending marginal wholesale price signals, these signals do not substitute for the need to run regional and utility-specific conservation programs. Some programs -- for example, codes or market-making efforts -- are only workable and cost-effective at the regional level. In fact, conservation programs become more important at higher prices, because they are designed not only to substitute for market signals but to correct fundamental market imperfections -- such as access to reliable information, access to capital, split incentives (such as between builders and buyers, architects and builders, or landlords and tenants), and differences in risk and discount rates. Well-designed programs are specifically tailored to address these issues and work with market signals. One need not look beyond the cities of New York, San Diego, and Honolulu to see that high energy prices do not resolve market failures or stimulate -- on their own -- comprehensive investments in energy efficiency. We must work carefully to ensure that price signals are supported by carefully chosen and efficiently run conservation programs.

3. ***BPA is considering unbundling the services it provides such as transmission, storage, load shaping, and integration services. What are the potential benefits and drawbacks of unbundling? If BPA pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some BPA services that cannot be unbundled?***

BPA provides many melded services. Put most simply, BPA's most tangible products include firm and non-firm energy, capacity, instantaneous and planning reserves, interconnection charges, shaping, and transmission or wheeling services. Currently, BPA melds all of its preference customer services into essentially one priority firm (PF) rate. Unbundled rates would distinguish between raw kilowatt-hours and the other power services necessary to transform

kilowatt-hours into useful services. By unbundling these services, BPA would provide customers with a range of services from which to choose. Customers who prefer to remain entirely dependent on BPA could buy all these services individually or as a package. Customers who choose to develop some of their own resources could buy fewer services.

The interactions between tiered rates and unbundling are likely to be complex. For example, since many BPA costs involve fixed capital performing many functions, any cost allocation for unbundling could be seen as arbitrary. Moreover, the fixed assets would need to be allocated under tiered rate principles - which largely associate the assets of the system with preference customers - and unbundling - which is primarily based on cost. In other industries such as telecommunications, where there is a high level of fixed costs, the debate over unbundling has proven lengthy and contentious. Nevertheless, we believe that BPA will face difficulties if it elects tiered rates without comprehensive unbundling.

BPA might consider unbundling certain fixed, statutory obligations - such as fish and wildlife programs and the low density discount - and charge a proportionate share on an annual basis to all customers who buy any service from BPA. This could help ensure that regional costs are borne regionwide.

Finally, we believe that stability in this environment is important but very difficult to achieve. BPA needs to ensure that it recovers its costs and customers need to be able to make decisions on relatively stable prices. These may be competing objectives in a continually changing market environment. However, successful implementation of long term regional plans cannot occur in an environment of rapidly changing prices and services.

4. ***How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must BPA do to ensure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection of fish and wildlife?***

The costs of protecting endangered fish and other species should primarily be included in the price of first tier resources. These costs are clearly related to the availability of inexpensive federal base resources. It is also true that changes in river operations can increase the availability of non-firm resources and decrease BPA's ability to shape power or meet capacity requirements. Both of these costs would tend to be reflected in higher costs for unbundled services.

Other non-market environmental costs are associated with resource acquisition. BPA made some provision for offsetting future carbon emissions from the Tenaska II plant. Private utilities in the Pacific Northwest typically consider such externalities in their integrated resource plans. They have a choice of assuming surrogate values for future regulations or market measures or assuming the risk of disallowance of expenditures or non-operation of a facility. BPA could condition access to first tier resources on completion of integrated resource plans that consider long term costs including externalities.

4a. How can the region maintain the benefits of regional coordination and planning if resource acquisition and transmission become more decentralized as a result of tiered rates and unbundling?

The benefits of regional cooperation have been extremely significant. They have allowed us to spread the risks and costs of investment among many users, and capture large economies of scale. Through its ownership and maintenance of transmission and access to federal hydropower, BPA is a central decision maker whose influence on the Northwest electricity market is considerable, almost regardless of the way its services are priced.

While it is not absolutely clear that new BPA prices and services will result in increased decentralization, it is important to consider the consequences if they do. In such a case, we are likely to face higher prices and lower reliability. The Power Act was designed to spread the benefits of a coordinated system and costs of associated obligations throughout the region. If we encourage competition, it should be based on real price differences caused by technology or efficiency - not based on the ability to escape those regional obligations. One possible though controversial model is to use power sales contracts to ensure that if you choose to have any of the benefits of the BPA system, you must pay for costs and risks imposed on those least able to escape reliance on the federal system.

5. ***Should the variable rate for the Direct Service Industries (DSIs) be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional rate payers of continuing to provide this variable rate.***

The Pacific Northwest hydro system has comparatively little storage; it is dominated by run-of-the-river projects that must provide flows to meet a variety of water quality, fish and wildlife, irrigation, flood control, recreation, and river transportation requirements. During the last decade surplus, variable rates for direct service industries provided clear value to the region's ratepayers, to BPA, and to fish and wildlife programs because we were able to sell power that would otherwise have no market. As we move toward deficit, this value is in question and DSI rates, in our view, are appropriately being revisited. The fundamental river conditions, however, have not changed. It is quite possible to imagine relatively low rates for DSIs, based on the reserves they provide the system and the constant load and revenues they provide BPA during periods of time when water must be released for fish, recreation, water quality, flood control, and other non-power reasons.

As a point of departure, new long term sales contracts with the DSIs ought to be based today on their value to the power system. Because these loads have very unusual characteristics, it is our expectation that DSI contracts will reflect a fully-unbundled cost-based approach. It may be possible to have contracts that incorporate these power system values and are sensitive to the price of aluminum in the world market. Such an approach is possible regardless of the steps BPA might take with other customers.

6. Should the irrigation discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this discount?

The irrigation discount was incorporated into the Northwest Power Act at a time of regional electric surplus. Much like the DSI rate, the discount clearly made sense when BPA's choice was to run water through its dams and capture no revenue or run water through its dams and capture modest revenues from agriculture. Currently, the discount provides rates that are 80 percent of the priority firm rate. As the surplus has evaporated, the value of the discount to the power system has been called into question.

Agriculture is an important part of the Washington economy. For example, the food processing industry is our state's second largest employer. The irrigation discount has provided some certainty in an otherwise volatile business. We believe it is important that BPA consider the vulnerability of this industry to changing electricity prices as it reviews its own products and services. For these reasons, the state of Washington believes the irrigation discount should not be automatically eliminated, but could be modified to reflect the new realities of the Northwest electricity marketplace and the role of a restructured BPA.

10. How should the long-term power contracts that BPA is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

The negotiation of power sales contracts should not be a process by which regional electricity priorities and policies are set; it should be a process by which regional policies and priorities are implemented. Long term power sales contracts must reinforce regional responsibility for those customers who take advantage of the energy and capacity services of the federal base system.

WSEO is currently participating in long term sales contract discussions and intends to continue doing so. In our view, the provisions of these contracts should ensure that the goals of the Power Act are met by long term customers of BPA.

11. It has been suggested that the residential exchange program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

The residential exchange was a vital compromise in the passage of the Northwest Power Act. The exchange was invented to settle on-going litigation over who BPA's customers were. Public utilities agreed to the exchange to get Congressional support necessary to pass the act. However, the publics felt strongly that their rates should not rise as a consequence of the exchange. The theory was that the Direct Service Industries would pay for the cost of this arrangement in exchange for long term power sales contracts. The theory changed in 1985 to make the DSI rates and industrial rates of customers of BPA similar. It is becoming harder and harder to estimate who is bearing the cost of the exchange. It is clearly placing significant pressure on the PF rate paid by public customers of BPA.

The issue raised is whether the exchange rewards less efficient resource acquisition. In our view, while the exchange could, in theory, reward inefficiency, BPA and utility regulators have adequate tools to ensure efficiency, such as audits and prudency reviews.

In summary, we have reached five principal conclusions:

- The Governor and cabinet agencies of Washington support the fundamental principles of the Northwest Power Act, calling for: 1) shared distribution in the risks and benefits of the existing hydroelectric system, 2) resource acquisition by BPA on behalf of public utilities and by private utilities in the priority order established in the current power plan, and 3) aggressive investment to restore threatened fish and wildlife populations. We pledge to work with BPA to implement proposals that improve efficiency and help achieve the goals of the Power Act.

- We strongly support BPA's efforts to maintain competitively priced electricity, reduce costs, and improve the efficiency of service delivery.

- We do not believe BPA is in imminent danger of becoming uncompetitive as an energy efficiency or generation resource provider. Reasoned implementation of efficiencies should allow BPA to remain competitive, and continue to provide regional conservation and fish and wildlife programs.

- We support improving the price signals sent to BPA customers, but caution that price signals alone cannot replace programs. Rather, price must work with programs to make conservation markets work.

- We need to begin considering real examples of tiered rates and unbundled services. We are concerned that speculation over the future of BPA products and services *could* lead to uncoordinated investments in new gas-fired generating capacity or stagnation in acquiring conservation resources. In our view, both of these results are risky, short-sighted, and important to avoid. Some gas generation is needed to meet regional energy loads at

reasonable cost in coordination with the hydro system. However, we may see applications for over 3000 megawatts of gas generation filed with our state's facility siting agency this year and next, much of it designed to undercut BPA sales. Over commitment to gas resources could be damaging to BPA and public utilities' financial health, as well as to the energy efficiency, renewable energy, and fish and wildlife provisions of the regional power act. In particular, BPA could find it difficult to improve conditions for fish or meet its legal or financial obligations with a large and growing number of base load gas combined cycles.

Mr. Chairman, this concludes our testimony. I would like to thank you again for allowing the executive agencies of the state of Washington to provide this testimony today. I look forward to working with your committee and our Governor and Congressional delegation on these issues.

Mr. DEFAZIO. Thank you and thank everybody for their succinct and thoughtful testimony.

We will now begin a couple of rounds of questions. I am sure I will not finish my first round. I think I will start with some of the points Ms. Merchant was raising right at the very end there. I have a question about unbundling that I would like each of the groups or everyone, if they so wish, to address. It goes to the unbundling issue. My concern is that when you begin to unbundle services, particularly when you talk about unbundling fish and wildlife—I do not know how we unbundle an obligation exactly. But in any case, when you begin to unbundle these services, various customers or players in the region are going to have different capabilities, and I am worried that we will find that some major players may want to come in and cherry pick certain services from BPA while they have the economies of scale to fill in those other gaps and other utilities would remain captive. Then the question is, what does happen to those obligations, the underlying debt, the fish and wildlife obligations and the other things that BPA has to continue to handle. How do we get those utilities over here, you know, who have cherry picked, so to speak, in the unbundling of services to carry their fair share of the total obligation in the region which makes those other services available to them. The pricing mechanism, it seems to me, is going to be very problematic, and I question how far you can take unbundling and what things are appropriately unbundled and what are not. This also will obviously go back to tiered rates and what is in the base and what is not in the base. If you could just perhaps allay some of my concerns about unbundling, it would be helpful.

Mr. HARDY. Well, first of all, we are not going to unbundle fish and wildlife. I agree with you, that is not one of the things I am contemplating. We are going to try to unbundle our basic power products in much the way that you have described, Mr. Chairman, with different combinations of capacity and energy and different combinations of storage, load shaping, load factoring combined in different ways. Precisely what you have described can occur. Different people can participate in different ways that are most appropriate to their circumstances. That is all part of the marketing plan currently under development. We will have that in shape to start discussing publicly probably about the first of December, although we have already started some discussions that are preliminary in nature. And once we have that in that form, after the first of December, we will actually start testing products or bringing out different products for review within the region to see what some of the consequences of providing those products are as well as who the takers might be.

I contemplate that what we are going to see is that those who have the capability to take advantage of different types of products will probably pay more for those kinds of products than perhaps they are paying now, but overall they will get a higher value for that product.

Mr. DEFAZIO. Okay, if someone, say a small utility, were buying a more melded rate, if we continued to provide that, or vanilla rate or whatever we want to call it, that the actual value of, say, one of the major unbundled services—whether it was load shaping or

whatever else here—actually, the value of that outside of their package would be priced marginally higher in case someone is just choosing that service?

Mr. HARDY. Right. If you had a product that involved substantial shaping or load factoring component, it is going to be a generating utility or a potential generator that is going to be interested in that product, as opposed to right now where storage shaping and load factoring are all kind of rolled into the priority firm rate. It is all melded in and without much regard to who gets what. We can price that more differentially. My hope is that, for a significant number of those products, we can price them differentially and collect more revenue overall for those products. They will also provide higher value. Some utilities will want heavy load hour energy in particular times of the day. Seattle and Tacoma have big sustained peak problems in the middle of the day. That is what they are interested in. Other utilities are more interested in needle peaks and the capacity to cover those kinds of swings. Irrigation utilities are interested in energy that might meet the irrigation load shape. We will try to provide a different mix of products that both collects more revenue and actually is of higher value to that customer, particularly in the case of the generating utilities. It allows them to combine that with their own generation to make a third-party sale even though they are in California or somewhere else. So even though they are paying more for the product they are getting from us, they are able to mark it up and make up from a third-party sale. Those are some of the kinds of examples.

Mr. DEFAZIO. Sure. But this is all new ground.

Mr. HARDY. Absolutely.

Mr. DEFAZIO. If I could, Randy, maybe just to shape your remarks a little bit more. We have two-year rates and it is a very ponderous process. I am concerned that if we go to unbundling and we unbundle a whole sector of services, that we have to build in some capability of constant or more short-term adjustments because we are not going to fully understand the implications of these things when we first put them out.

Mr. HARDY. It is probably true that one of the major challenges we will have is meshing this kind of a process which requires near-term response to market signals with the Regional Act, 7–I rate process, which is around a year and a half exercise this is going to present us with some unique challenges. Frankly am not sure how we resolve those. That is one of many issues. Believe me, we are essentially in the realm of speculation here because those are the very kinds of issues we are grappling with. The point I would like to make is, our objective here is in the aggregate really twofold. One, I think we will end up providing more value to individual utilities rather than the one-size-fits-all kind of product that we have now. Secondly, we will get the revenue recovery—a high revenue recovery—because we are providing that to more niche markets than a broad market. It will help do two things. It will keep rates overall lower, or the revenue requirement overall lower, and it will help support fish and wildlife obligations and the other regional obligations that we have. The alternative is to keep loading everything in the priority firm rate, look at a succession of double-digit rate increases, and we are in even worse shape relative to our

regional obligations. So that is what we are trying to get away from.

Mr. DEFAZIO. Do Council members have any comment on this?

Mr. TRULOVE. The Council has looked a little bit at the idea of unbundling. We are eager to participate with Bonneville in understanding exactly what their product mix is going to be because we do have some concerns. I mean, we all have concerns about how will this work out. The questions that have been raised just recently, but also in terms of such time-honored practices as preference. What does preference mean to the various unbundled services?

From the standpoint of energy planning, the Council and the region in the past have pretty much been dominated by considerations of energy. We have looked at what kinds of power plants would be appropriate from purely an energy standpoint. As we are moving into the future and as we have been making adjustments to the system and operations of the system to the benefit of fish and wildlife, we have had, I think, some fairly profound effects on the system's capacity. As we unbundle, now we are looking at much finer distribution of services across the electrical industry. I think the Council is going to need to rethink its power planning capability in terms of what kind of a mix of resources would better fit in an unbundled world. That is new ground that we still have to plow. We are eager to begin the discussions. I think we all await Bonneville's first cut at their business plan and maybe some participation in that so that we can do a better job of it.

Mr. DEFAZIO. Are you involved in the ongoing development of the business plan, or is this a case where they are going to develop it internally and then present it to you?

Mr. TRULOVE. Well, I think we are working with Bonneville in terms of their function-by-function review. Now in terms of business plan, it is at a stage where I think Bonneville has to put something on the table and that is what they are doing now. We are very eager to catch on and participate as a partner with them just as soon as they get something on that table. I think from the standpoint of environmental considerations, too one of the things the Council has been striving for has been to very explicitly incorporate environmental considerations in our decisions. Up to this point, we have made explicit decisions; for example, that coal is not acceptable in the region in a pulverized form. So we made very explicit decisions about what you could and could not do. We have said that you could not develop hydro in certain areas. I think in the future, particularly with unbundling, we have got to look at a different system configuration, different mixes of resources and try to find the one that is the one that is the most environmentally friendly and one that has a role for renewables development. All of this makes power planting much more complex, I think. It is going to be a real trick for we in the region to figure out how to add the most value in this unbundled world.

Mr. DUNCAN. I think there is probably a lot of frustration, which many of us share with many of Bonneville's customers, about what the unbundled mix of products is going to look like. The marketing plan is one that is being dealt with mostly internally right now. While I believe that Bonneville probably ought to make sure its got

its own thinking pretty well together before it puts that out on the table, it is also important that they put out on the table something which is accessible to change and to criticism and comment by all us in the region who are going to be affected.

You really have raised a couple of questions. One of which is unbundling of products and the second is the question of access to the region's goods from reciprocal obligations back to the region. And I think for analytical purposes, it is useful to separate those two. I do not have a lot of serious heartburn, I guess, about unbundling the services and making those available. You know, one person's cherry picking is another person's market efficiency. And it may well be that most of Bonneville's customers and the rest of us are going to be better off if those products are unbundled and priced in a way that we do not have to buy what we do not need. It is going to be tricky, however, to figure out how to price those and how to allocate those so, as you say, we do not leave some parties, particularly those with relatively little market power sitting on the outside looking in. There is a question, as the Administrator observed, of how you price those. And that is still an issue that is very unclear in the region. I think overall the notion of sorting through what we have to sell and what we have to buy is a positive thing and is going to yield some real benefits for the region.

The other question of how you tie access to those regional goods—the value of the hydo system; the water that flows down; the investment in the dams and the transmission lines; reciprocal obligations that support the Power Act; and the Region's fish and wildlife goals and so on—is a question that cannot be addressed entirely separately but absolutely has to be addressed. Disagreement is not the right word, but I think the Council members are still sorting through how we think that ought to play out. Clearly, there still needs to remain a linkage. A utility or a DSI ought not to be able to, as you put it, cherry pick the region's goods and not have any obligations back.

Mr. DEFAZIO. Thank you.

Ms. Merchant, if you will just keep it on the top of your mind since my time has expired, I will ask you the same question when my round begins.

I will defer now to Mr. LaRocco.

Mr. LAROCCO. Thank you, Mr. Chairman.

Mr. Hardy more or less described BPA as the AT&T of long distance telephone lines. I do not think any court is going to demand that you, you know, go into regionals or, you know, break up. You had mentioned that the utility market was changing all over the country. Can you give me some idea whether this is a national phenomenon or whether it is regional and whether there are any success stories ahead of BPA that have been changing ahead of the curve?

Mr. HARDY. Clearly, it is a national phenomenon. I think you will probably hear from some of the other utility witnesses today, even though they are in this region, who are seeing the same future. I would say that my experience in the industry has been that when you get together, for instance, at an Electric Power Research Institute meeting, which is the opportunity I usually have where you

get Chief Executive Officers from all around the country, they are all thinking about and dealing with the same thing.

You look at utilities across the country, they are downsizing just as we are, just as other industries are. It is one indicator of that trend. Pacific Gas and Electric, the largest utility in the country, in Northern California announced about an 11 percent downsizing two months ago. So, that element you see. And, you see the same unbundling occurring in the larger integrated utilities as well. It goes all the way to spinning off subsidiaries to look at specific aspects of the transmission business. Many of them have already spun off subsidiaries, Mission Energy of Southern California Edison being one primary example, to go into the IPP generation business. They are looking for profit opportunities, and they are looking to position themselves to take advantage of this same change. So, we are seeing that as pretty much an industry-wide phenomenon. It actually started, you know, several years ago but will be greatly accelerated by passage of the Energy Policy Act and the new power given to FERC to mandate transmission access that will assist, if you will, the market forces that are already in motion. People see that the change coming is analogous to the gas company. If you are a transmission provider like Bonneville is, like Pacific Corp is, you can envision a day where you may be like a pipeline company and you simply have a common carrier status without any priority on your lines. Those sorts of things are occurring and virtually every large utility, public and private in the United States is trying to cope with those same sorts of issues, Mr. LaRocco.

Mr. LaRocco. Well, carrying it further, what can you say to the upstream users and people up in Idaho who might be concerned that all of this might mean that there is going to be some deemphasis on fish and wildlife and the commitment to fish and so forth? I mean, I think we all understand the efficiencies and so forth.

Mr. Hardy. What I would say is this—they ought to be fundamentally invested in our success in this endeavor because our failure will directly lead to unfunding of fish and wildlife programs and the other regional benefits. If we do not remain competitive, we are going—as I said in my opening statement—start to miss Treasury payments. We will look at a shrinkage of our load base. What we will have left in the worst case—we will not go out of business, I do not think—but what we will have left is all the nongenerators who do not have any capability to do anything but buy power from us. That is half of the load base we currently have. And, you are going to spread a given amount of fixed cost over a smaller kilowatt hour sales base and your rates go through the roof and that has a self-perpetuating kind of downward spiral. That is the vision. So, we need to be successful in our Competitiveness Project in order that we continue to have stability in growth and revenue. We generate the new wealth, if you will, that provides both rate stability and provides the funding for our fish and other environmental obligations. If we are not successful, the exact opposite occurs.

Mr. LaRocco. You have talked about today—and yesterday in Boise when the focus was on salmon—giving stake holders, particularly environmental and other public interest groups, an incentive

to support BPA's economic well being, so you can, just as you say, continue to fund its fish and wildlife conservation responsibilities. Could you expand on what those incentives are that you might see?

Mr. HARDY. As we saw the competitive environment unfolding before us, we asked ourselves the very questions that Angus surfaced about our regional responsibilities. How do we ensure that those continue to be maintained—specifically our fish and wildlife responsibilities? One of the frustrations that we have is that right now my perception is the fishery agencies and the tribes are not invested in our financial success. Frankly, we are running these programs more like entitlement programs than as results oriented fish programs. That is frustrating to the agencies and the tribes, and believe me, it is extremely frustrating to me to be spending $300 million a year and not know whether I am getting any results for it. The suggestion of turning the lump sum of money over to the Fish and Wildlife Service or something else has an appeal, if you can take that and combine it with a trust-type concept such as we have done in the wildlife area in your State and in Montana, where that actually relieves Bonneville of some of the ultimate mitigation obligations. I mean, you provide a lump sum of money with no strings attached in exchange for getting some certainty as to what your ultimate obligation is. That is the kind of concept we were talking about. There are other variants on that like a base level of funding for fish and wildlife that can go up in good water years. You build your overall financial reserve above a certain level. Right now, the target in our rate case is roughly $400 million by the end of fiscal year 1995. If you had a couple of good water years, you had good aluminum prices with the variable rate like we had back in the late 1980s and you build that reserve, say over $700 or $800 million—you probably do not want to build it anymore than that—some portion of that might go to additional fish funds. Some portion of it might also go to rate relief. Those kinds of things. So those are two or three different conceptual ways to get at having the fisheries community more invested for financial success rather than viewing us as a deep pocket where the answer is always, Just spend more. My ability to do that is getting stretched to its limits right now, not to mention what it may be 2 or 3 years from now.

Mr. LAROCCO. Well yesterday, it was even suggested that somebody is continually trying to encourage the tribes to file lawsuits. That is not exactly an incentive. That is just the opposite. I mean, that is not a user-friendly relationship. It is a confrontational relationship that I hope we can avoid in a lot of ways with BPA. Are you afraid that maybe in the customer base at some point, everybody may fear being the last customer of BPA? In other words, there a major push towards IPPs, you know, or is this a smaller phenomenon?

Mr. HARDY. Right now, I would say there is cause for concern, but not alarm. The priority firm rate right now is 27 mills. The cost of acquiring a new combustion turbine is more like probably 35 mills. Maybe there are a couple out there that are closer to 30 mills. So we have not reached the crossover point of our priority firm rate with the cost of the resource acquisitions yet. I think it will be some time before that actually occurs. But even with that,

you see Clark and Snohomish, EWEB and others proceeding to decrease their dependance on us, or at least taking the initial steps to do that. I think the calculation that they are making is, even though the crossover point is not out there, they think our rates are going to go up by substantially more than we think they are going to, and they see a lot of uncertainties. They see fish-and-wildlife-related ESA uncertainties out there. They see repayment reform. They see potential nuclear plant decommissioning costs—none of which have been factored into our rates yet—and they say, I will take a risk on gas prices and supply in exchange for those kinds of risks. So, I will start to diversify my sources of supply. If those initial kind of forays into the turbine marketplace become a wholesale rush, we have got a major problem. That is one of the things we are trying to address in the Competitiveness Project—to ensure our customers we have got control of our rates. We are going to remain a reliable low-cost power supplier so that does not happen. It is kind of Angus' scenario number two, if you will.

Bonneville continues to be the resource provider of choice for at least a number of the utilities in the region, and you have the stability of rates and of fish and other benefits that we have essentially projected.

Mr. LAROCCO. It seems to me that there is a rate question if somebody takes the risk and leaves for cheaper rates and that risk does not payoff, does not work out, and you are sitting there and you always are—BPA is always there. How do you handle that in terms of rate structure down the road? I mean, if you lose part of your customer base and that does not work out and they come back 3 years later and say, here we are, we are your best friend. Remember us? What is our rate? I mean, that uncertainty is not good for the region as well, is it?

Mr. HARDY. That is right. It sounds like an unbundled product to me.

Mr. LAROCCO. It sounds like market forces at work, and you have to be able to——

Mr. HARDY. I think you have made a point. The backup reliability that our transmission system provides is worth a considerable amount and in some way that has to be reflected in the mix of unbundled products and services that we have. But it has also got to be able to compete with other market forces out there, and that is the challenge that we have.

Mr. LAROCCO. One last question, Mr. Chairman, and Administrator Hardy. When many agencies modernize, they say they have to get lean and mean and more efficient. Say it is going to cost a hell of a lot more money. Do you anticipate this in the Competitiveness Project. Is this built into the rate increase or do you anticipate needing more money to bring in more technology, or is this going to be able to be accomplished without an influx or surge of money?

Mr. HARDY. I am anticipating that this can be accomplished within the constraints of what we project our existing rates to be. The whole purpose of this exercise is to decrease costs, not to increase them. We are not seeking a strategy of major investments up front that will give us benefits 10 years down the line.

Mr. LAROCCO. That is what I am talking about.

Mr. HARDY. I am cutting staff, over the next 2 or 3 years by 15 percent, and I am also seeking to raise revenue through the unbundling of products that I hope will have an immediate effect on the 1995 rate increase.

Mr. LAROCCO. Okay. Just one final thing that is sort of fuzzy in mind is the public involvement in your business plan or the Competitiveness Project, whether it is like an EIS, where there are scoping and comments and so forth.

Mr. HARDY. There will be various stages of public involvement. As both Tom and Angus alluded to, they are both involved in different aspects of our function-by-function review as is Ralph Cavannah of the National Resource Defense Council and Ted Strong of the Columbia Inter-Tribal Fish Commission. In addition to customers, which are the predominant group, we also have representatives of other interests that are involved in the efficiency part of the exercise. When we go out with the marketing plan, we will clearly involve mainly our customers, but additional groups will be involved in the business plan. We have not decided what the best form of that is. As we actually start to implement some of these measures, the implementation vehicles will be the power sales contract renegotiation, the 1995 rate case, and the related EIS processes, all of which will have substantial public involvement components for the general public, public interest groups, and other interests as well.

Mr. LAROCCO. Okay. Thank you, Mr. Chairman.

Mr. DEFAZIO. Thank you. That was a good round of questions.

Ms. Merchant, have you thought any more about the concerns of unbundling?

Ms. MERCHANT. You have raised some questions—in fact, both of you have—that are additional to the questions we have raised. Right now, there are probably more questions than answers in any of our minds. The function-by-function review and reinventing government in terms of bureaucratic structure is something not only Bonneville is doing, but certainly state government is doing as well. It is very difficult and we applaud the effort and will work with Bonneville very closely in terms of our association and programs that we share.

You can hear in my testimony how we have created various constructs that can lead to possible results. The volatility of the energy industry right now in terms of signals—for example, gas is cheap now. It may not be cheap tomorrow. And so, as we lay out these constructs, it may make sense in one market perspective, but it may change very rapidly. I can see some value if Bonneville wants to maintain its competitive strength. We believe it is competitive now. And, of course, that is probably an area of disagreement among many people in this room as to how strong its competitive nature is. And changes, the different view you have as you lay out the scenario. Whether unbundling and tiered rates will actually decentralize, or will it just give the message and maybe the promise that will not come true that it will be decentralized, I think, is a pretty fundamental question. Because it can lead to all sorts of decisions, particularly related to gas-generated power and investments, and it can create such instability that you cannot help but continually ask the question. Are we creating more problems or are

we solving problems? I do not have the answer to that. But I am looking forward to the information that is forthcoming because I think we all really have to examine that very carefully together. There is so much at stake here.

Mr. DEFAZIO. Right. Sort of like being in the airport and trying to figure out how the alternate phone service works and what it really costs. Did the consumers come out ahead there? Whereas in some of the other things like MCI and Sprint, that is pretty clear that consumers have come out ahead. You know, unintended effects are something we have to guard against.

I would like to propose one possibility, and this goes to some of the obligations in the region. I mean, one concern I have is utilities that are customers—at least those over which BPA has some authority. Right now, going out and departing in their acquisitions from what we see as a prudent least-cost path using conservation and renewables. In the energy legislation last year, we basically mandated that customers who got any fraction of their power or services through the Western Area Power Marketing Administration would be required to develop least-cost plans and implement those plans. Do you think that is something that we should be looking at here?

Mr. HARDY. Well, I think it is premature, Mr. Chairman, at this time to look at that. I mean, we have got a least-cost plan. It is the Council's plan.

Mr. DEFAZIO. Right. But an individual utility is not bound by that in terms of their going out and purchasing, you know, a gas fired turbine or something at this point.

Mr. HARDY. That is correct. The utility can exercise its own discretion to do that, although most of the investor-owned utilities, for example, who do not buy any power from us, already have least-cost planning requirements by virtue of their Public Utility Commission's kind of requirements.

Mr. DEFAZIO. How about your publics then?

Mr. HARDY. Well, most of the publics buy power from us——

Mr. DEFAZIO. Right.

Mr. HARDY. Most of them buy at least some significant portion of their power from us and hence are influenced to a very substantial extent by the Regional Power Act. Set the Mid-Columbias aside for a second, the other two major utilities probably that do not buy all of their power from us are Seattle and Tacoma. Each of which have, by virtue of their own city councils, a very sophisticated integrated, resource plan to begin with. So I do not think there is a problem now. There may be a problem in the future, and it may be appropriate in the future to consider that kind of a requirement. What I would argue is, if we can be successful in being competitive, the Council's Regional Plan will still continue to guide those actions, and we will not need to take what will inevitably be a much heavier regulatory action. I think that is a preferable way to go about it. If it does not work, then I think the kind of suggestion you are making may well be the direction you want to go in.

Mr. DEFAZIO. Would the Council like to comment on that? How, in this world of diversified, unbundled, competitive services, do we maintain the overarching mandate of the plan and the plans we have for the region. How can we constrain what may not be the

most prudent individual acquisitions? Because there are some people out there—and you heard some of the testimony when we were in Portland—they are going to go out and buy resources that do not even seem to make real economic sense, so far as we can see. But they are just bound and determined they want to get away from BPA because they are upset or whatever. They are uncertain.

Mr. HARDY. Sure, absolutely.

Mr. DEFAZIO. I mean, I am not sure that the plan's charge is sufficient to keep those people on the least-cost conservation renewable path. I mean, how does the Council feel?

Mr. TRULOVE. Well, you have identified a problem that we are struggling with in trying to figure out the best solution as all of this evolves. It is not clear that a whole collection of individual utility least-cost plans adds up to the regional whole. There are enormous regional benefits from this system. I mean, we have recognized that from everything from the coordination agreement to nearly everything we have done in the history of the system. And those are worth maintaining, including the obligation to fish and wildlife. So a bunch of individual utility least-cost plans probably are a pretty good idea for the utilities involved, but from the regional standpoint, maybe there is another linkage that is needed. I think we are still in the position of trying to puzzle this out and look forward to working with you on it.

The other thing it seems to me in terms of the uncertainty, what would drive people away from Bonneville, there are some very real things that the Congress can do, Mr. Chairman. One of the unusual uncertainties here is the constant threat of repayment reform. If we could figure a way to get beyond that, that then levels the playing field, and the kinds of uncertainties people see with Bonneville I think are more manageable. Actually, I think we must make a more accountable sort of event. I think we can get there. That is the kind of risk that we ought to be able to manage if we have a regional plan that people are supporting. Not everyone is going to support or feel like the regional plan is the best thing for them in every aspect. But as a region together, supporting a plan that is acceptable to all these different interests—and we think that is sort of what the Council is trying to put together—and implementing that plan with accountability ought to be a way for the region to protect itself against unknown escalations in those costs. I think we can handle that.

Mr. DEFAZIO. This does go a little bit back to Mr. LaRocco's question, though. I still have this concern. You know, let me just read something from BPA's testimony on page 20 in the answers to my questions. "A decentralized system would allow environmental values to be expressed at the community level. Local communities would make their investment decisions based on their environmental values and their ability to make long-term investment decisions." Well, if you were in Idaho yesterday and you heard some of the testimony I heard from some people in proximity to some of those dams on the Snake River, their environmental values are not too enlightened. They may have great self-interest, but I am a little concerned at that sort of decentralization with no overall mandate or hammer—or potential of a hammer. Let me give you one idea I have. You can deal with this in the rate structure. If a utility is

a partial customer or wants to be an unbundled customer or if they want to access anything from BPA, there is one set of rates for people who conform with the plan and there is another set of rates for people who do not. And if they want to come back at a future date and they have departed from the plan, they cannot get back to that first schedule. There is going to be a little penalty. So, at least, they might think at the outset before they make some of these irrevocable decisions and saddle their ratepayers or the region with unneeded, unwanted, inefficient generation or whatever else, that there is an irrevocable decision beyond just that little acquisition in terms of the condition that they are never going to be able to get back quite to the status they had before because they chose to go outside the path which has been chosen for the region.

Have you got a comment on that?

Mr. DUNCAN. Yes We cannot get a willing buyer, willing seller, arms length, not using any of the region's goods kinds of transactions, nor should we. If a utility wants to cut a deal with an IPP and to own its own generation, it is entitled to do that. But it has to carry some commensurate risk. It is pretty clear that a 28 mill resource that an individual utility buys is not necessarily a lot cheaper than a 35 mill resource that Bonneville buys and can shape and manage and dispatch in economical ways to distribute risk and so on. That more expensive resource is not necessarily more expensive. So a utility that buys a 28 mill resource is almost certainly going to come knocking on the door. There may be a few transactions that can be done independently. But I think most of them are going to come knocking on the door because of the economic value of the other goods, if you will, that Bonneville has to sell. There certainly is not closure on what kind of reciprocal obligations there ought to be or what kinds of mechanics you use to implement those reciprocal obligations. You know, you have mentioned one which I have certainly heard characterized as a different price mechanism. Another one is, you know, first in line. A preference which is a little less onerous, but it says that if you do not have a least-cost plan that has been found consistent with the regional least-cost plan or certified by Bonneville or something like that, that you can always be bumped out of line by someone who has. You know, there may be a mechanism that says if you develop your own resource and it turns into a turnkey and you want to bring it back to the region, and right now you have a right to place a load on Bonneville, you will not necessarily have a right to bring that resource in at the price that makes you whole again.

Mr. DEFAZIO. We could deal with this in tiered rates, too.

Mr. DUNCAN. You could deal with it with tiered rates as well.

Mr. DEFAZIO. You could subtract that from the tier that they would have had.

Mr. DUNCAN. Yes. But I think, again, you want to deal with this question in two separate chunks. One is, you want to establish conceptually whether there ought to be that kind of reciprocal obligation if you are sharing in the region's goods. And second, how mechanically do you implement that obligation and how forceful or how weak do you want that mechanism to be? But there is a spectrum of mechanisms that you could use.

Mr. DEFAZIO. Yes, but I do not think we can question the regional coordination and the reciprocal obligation. I mean I have seen some phenomenal numbers which start high and go really high in terms of the value of the coordinated system. And all we have to do is go back and look at WPPSS and understand what happens when we start going off on tangents. Of course, unfortunately BPA itself was——

Mr. DUNCAN. That was a regional tangent.

Mr. DEFAZIO. Yes, it was regional tangent. [Laughter.]

Not a good example of exactly what I am talking about here, but you know, it was started by an individual group of utilities.

Ms. Merchant, did you have any comment on this?

Ms. MERCHANT. No.

Mr. DEFAZIO. Okay.

Mr. LaRocco, do you have further questions? Let me just sort of review—I will have more opportunities, but let me see. To the Administrator it has been some time since our Portland hearing and you have had several meetings of the group that is working on tiered rates, and as I read your testimony, your testimony says that we are going to move forward. The question is, What are the options with tiered rates? Are we still in that place?

Mr. HARDY. That is correct. We have a work group comprised of both customer and public interest groups, as well as the Council and other representatives that have looked at the tiered rates question two or three times. There are three basic options with an infinite number of variants they are looking at. What we do not have yet is the marketing plan. You know, that tiered rates discussion needs to be informed of what the unbundled services are. My guess is that this discussion probably occurs in December.

Mr. DEFAZIO. We are still headed toward tier rates in your opinion?

Mr. HARDY. As I testified at Congressman Wyden's hearing about two months ago, the question is not whether we do this, the question is just how, and from my perspective, how it meshes with the unbundled products and services. So I have crossed that threshold. For the very reason that I think you alluded to earlier, for the last 13 years, we have been achieving conservation almost entirely through offering very generous program incentives. And if we continue in that mode for the next 10 years, we are going to spend $3 billion on conservation. I just concluded that the delivery costs were going to kill us and that we had to lower the incentive levels on one hand but put in some form of tiered rates on the other hand. So you had a mixture of program incentives and price signals that got you to the same aggregate amount which is, the Council's 1,500 megawatt goal regionally, or our portion of that which is about 650 to 700 megawatts. You got to the same aggregate amount of conservation acquisition but with much less pressure on the priority firm rate.

Mr. DEFAZIO. In your review of the development of tiered rates, are we bringing in everything, including the DSIs, into the tiered rate discussion?

Mr. HARDY. We have not ruled anything out in terms of how it would apply. We really have not gotten to the question of deciding just how it applies to different customer groups.

Mr. DEFAZIO. Just one other thing. Correspondence that I saw that had gone to you—or I think I saw a report in the press about it. I cannot remember where. I think I saw the actual correspondence. At our last hearing in Portland, you had just before that entered into the contract with Emerald Public Utility District, who we will hear from a little bit later, for the conservation power plant. Then, I think subsequently, not too long after that, you get a letter from the DSIs urging you not to enter into any more of these agreements. Have you responded to them?

Mr. HARDY. I responded verbally, and I have told them that I am not going to accept their advice.

Mr. DEFAZIO. Thank you.

Mr. HARDY. I would like to explain that however.

Mr. DEFAZIO. Okay.

Mr. HARDY. The Emerald Public Utility District contract, as well as the signing other agreements we are going to sign—in fact we are one next week with the Washington Conservation and Renewable Energy System (CARES) utilities, which is made up of the six or seven public utilities in Washington State which has formed its own joint operating agency to do a conservation power plant sort of deal—all have off-ramps. So 2 years from now, if in fact we find it necessary to lower the incentives or change the incentive structure in very fundamental ways because we have put in tiered rates, we will change those contracts. And those utilities then have an off-ramp if they do not think that is a good enough deal. So, I have done my best in protecting against commitments that go on for 7 or 8 years when the marketplace changes around us. Each of those contracts has off-ramps. That is what we have negotiated with and we will have to see whether people choose to exercise those or not. I think that protects against the kind of concern that the direct service industries were worried about, but still has us moving forward with innovative conservation programs in the meantime at the lowest cost.

Mr. DEFAZIO. Right. I do not want to revisit that hearing, but, as you remember, at the time, the opinion that I expressed—and I think it would be a majority opinion in the Northwest delegation—would be that we are not going to get to the point where we do all of our conservation renewables and implementation of those mandates under the Act just through the market-pricing mechanism and message. There will be some residual continuing obligation on the part of BPA to provide some services, more direct services and incentives in those directions.

Mr. HARDY. I understand that and that is what we are trying to sort out in this kind of environment. I think with tiered rates, or some form of that and some change in our program incentives, we can do both. I do not know that for a certainty, but I am dedicated to trying to get to that result.

Mr. DEFAZIO. Right. And the other concern was that we do not do nothing in the anticipation of tiered rates.

Mr. HARDY. We are not doing nothing, Mr. Chairman. We are going ahead. As a result of that previous hearing, you will see several contracts signed to that effect, both with Energy Service Companies and with Conservation and Renewable Energy Systems (CARES) and others in the next 30 days.

Mr. DEFAZIO. I am pleased to hear that.

I am going to let this panel go and move on. I thank everybody for their participation and their answers and we will move on to the next panel.

Okay, the next panel is quite large. We do have enough chairs and you will just have to be cognizant of the need to move the microphone around. As soon as she puts down the placards, we will know which direction we are moving in. Okay, we are going from my right to left, Mr. Lorenzini, Mr. Drummond, Mr. Myers, Mr. Reiten, Mr. Crisson, Mr. Fergus Pilon and K.C. Golden.

We are prepared to receive your testimony, Mr. Lorenzini. Proceed as you wish.

PANEL CONSISTING OF PAUL LORENZINI, PRESIDENT, PACIFIC POWER, A DIVISION OF PACIFICORP; WILLIAM K. DRUMMOND, MANAGER, PUBLIC POWER COUNCIL; ROBERT V. MYERS, SENIOR VICE PRESIDENT OPERATIONS, PUGET SOUND POWER & LIGHT CO.; RICHARD G. REITEN, PRESIDENT, PORTLAND GENERAL ELECTRIC; MARK CRISSON, DIRECTOR OF UTILITIES, TACOMA PUBLIC UTILITIES, ON BEHALF OF PUBLIC GENERATING POOL; FERGUS A. PILON, GENERAL MANAGER, COLUMBIA RIVER PEOPLE'S UTILITY DISTRICT, ON BEHALF OF NON-GENERATING PUBLIC UTILITIES; AND K.C. GOLDEN, EXECUTIVE DIRECTOR, NORTHWEST CONSERVATION ACT COALITION

STATEMENT OF PAUL LORENZINI

Mr. LORENZINI. Thank you, Mr. Chairman. My name is Paul Lorenzini and I am the president of Pacific Power. We are an operating division of PacifiCorp. Together with Utah Power, we serve 1.3 million customers in the Pacific Northwest states. We also sell wholesale power throughout the West and as a major BPA customer, we are responsible for about one-tenth of the agency's revenues.

We come to the issue of competitiveness as a company that began to see these changes occur about a decade ago and began to make major changes to address them. During that period, we have cut cost; we have cut staff; we have entered into a merger with Utah Power and Light that achieved substantial savings; we have sought innovative wholesale transactions. As a result of all of those actions, we have achieved consistent reductions in our prices since 1985, all with the goal of becoming and remaining a low-cost producer to face what we see as an increasingly competitive environment.

BPA clearly faces the same competitive pressures and challenges that we do and they appear to be taking steps to control their costs. We think they deserve to be commended for the actions that they took to hold down the size of their price increase; for their function-by-function review; and their current plans to reduce their staff.

But reducing costs and controlling prices alone may not be enough to be competitive. We think they will need to be more competitive in their pricing, which we think means unbundling.

Currently, BPA incurs cost for programs and services that benefit some but not all of their customers, and yet, all of the customers

pay for those costs in a melded rate. At the same time, many customers, including ourselves, want and are willing to pay for discrete services and products that directly benefit them and not others—transmission services, load shaping, energy storage, as well as new resources. And we believe that unbundling is part of the answer to that.

In the area of transmission, we think BPA should adopt the same practices and pricing requirements for transmission access as will be the norm for others. And we believe there are many opportunities to restructure their rates in the transmission area.

Second, we do support tiered rates for new resources. As we see it, under tiered rates the existing federal power system would be priced at one rate reflecting its cost, and new acquisitions to meet demand growth would be priced at a higher rate reflecting the cost of those new resources. That way, only customers needing BPA to provide new resources would pay for them. Plus, buyers are able to determine whether BPA is their best choice for new resources and the marketplace would make the determination.

Finally, we encourage BPA to consider more innovative approaches to demand-side resource acquisition. We have encouraged them to look at some creative financing mechanisms. Currently the costs that BPA expends on conservation are spread across all customers regardless of the benefits they receive. Randy indicated that they could have been looking at a $3 billion conservation program over the next several years. If we pay 10 percent of that bill, our customers would pay $300 million, and yet, those conservation programs largely do not go to the benefit of our company and to our customers. We have advocated a different approach in which the customers who receive the benefits pay for them through an energy service charge. It more closely aligns the cost of demand-side programs to the customers who receive the benefit. It is an approach that we have tested, and we think it has worked particularly well in the commercial and in the industrial sectors.

I would also like to briefly comment on another area where we think improvements can be made that will make BPA more efficient and help control cost; and that is the residential exchange. The current exchange methodology has worked in the past to make the benefits of the federal hydrosystem available to all residential and small farm customers in the Northwest. However, looking to the future, the current methodology does not reward and may in fact penalize efficiency efforts of both the utilities and BPA. For example, PacifiCorp has reduced cost in real terms over the past 6 years at a time when BPA's costs were increasing. If we take the residential exchange at today's levels and if we are able to continue to control our costs better than BPA, the result will be that our customers will see reduced benefits of the residential exchange. On the other hand, if BPA does a good job of controlling their costs, it could be penalized because it would have to pay increased exchange benefits.

We recommend that the residential exchange should be re-examined to determine how efficiency can be encouraged and rewarded and not inadvertently discouraged. One way to approach this would be for BPA to begin collaborative discussions with residential exchange customers about a contract exchange settlement that would

lock in the exchange at present levels. A contract settlement could remove the existing disincentives for utilities and BPA to do what is most efficient; provide BPA greater certainty about future exchange costs and ensure that the benefits of the federal hydrosystem would be still available to all customers as originally envisioned by Congress.

Finally in closing, I would like to touch on the concept of BPA as a government corporation. BPA does need to be more streamlined. They have seen that; others have seen that. The customers do need answers and commitments from BPA in a more timely fashion. And as they look at alternatives for doing that, the government corporation concept has some appeal. It has some appeal in relieving them from some of the civil service rules and regulations, from some of the complicated government procurement regulations, as well as from the complications of the federal budget process. However, we are concerned about the structure that might be adopted and whether it will provide continued accountability to customers, to Congress and to the Administration. As we say, the devil is in the details, and so while we believe that there are some advantages to that concept, we are concerned about how it would be implemented and have some reservations about ways that that might be done.

In closing, I appreciate the opportunity to share these thoughts this morning. We continue to believe that one of BPA's chief roles in the region is to market the low-cost power from the federal hydropower system and that role must continue. The greater challenge is how to do that more efficiently.

Thank you for your time.

Mr. DEFAZIO. Thank you.

Mr. Drummond.

[Prepared statement of Mr. Lorenzini follows:]

COMMENTS BY PAUL LORENZINI
PRESIDENT, PACIFIC POWER
TO THE CONGRESSIONAL TASK FORCE
ON THE BONNEVILLE POWER ADMINISTRATION
SEPT. 25, 1993

Thank you, Mr. Chairman and members of the task force, for the opportunity to present PacifiCorp's views about the future of the Bonneville Power Administration.

I am Paul Lorenzini, president of Pacific Power, an operating division of PacifiCorp. Through Pacific Power and Utah Power, PacifiCorp serves 1.3 million retail customers in seven western states, including the four Northwest states that comprise the BPA region. We also offer power on a wholesale basis to other utilities -- public and private -- both in the Northwest and elsewhere in the West. So, as you can see, our area of operation overlaps substantially with BPA's.

I would like to offer you some comments on the future of Bonneville from three perspectives: First, as a utility dealing with the same competitive issues Bonneville now faces; second, as a major BPA customer that is responsible for roughly one-tenth of Bonneville's revenues; and, third, as a supplier of certain power and transmission services to BPA. In so doing, I hope to address most of the questions you raised in your invitation to testify at this hearing.

Our view is that Bonneville's role must evolve to respond to the competitive marketplace we all face. We are talking about a different role for BPA, not a diminished one.

I. The energy market of the present and the future does not and will not resemble that of the past.

About a decade ago, PacifiCorp realized the electric industry was undergoing a fundamental and permanent change. New, non-utility suppliers were emerging on the landscape, and were encouraged by enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). These new entities presented utilities, regulators and customers with

options for how energy supplies are acquired and used.

Utilities faced competition they had never seen before. Competitive forces became even more important with last year's enactment of the Energy Policy Act, which incudes provisions that revamp the Public Utility Holding Company Act and the transmission access sections of the Federal Power Act.

In response to this newly competitive marketplace, we developed a competitive strategy of being a low-cost energy provider. We reduced costs, cut prices and adopted innovative approaches to acquiring and managing our generating, transmission, and conservation resources.

Our approach to resource acquisition became less institutional and more market driven. We work with other utilities on operating agreements that enable us to use existing resources more efficiently and effectively as well as through our power exchange and resource management agreements with utilities in Colorado and Arizona. We develop new projects in partnership with other utilities, as we are doing with wind projects in Washington and Wyoming; we are talking with independent power producers, and we work with our own customers, on both cogeneration and demand-side resource opportunities.

Our merger with Utah Power is an excellent example of our response to competitive pressures. Through our merger we have taken advantage of seasonal diversity, economies of scale, expanded transmission and administrative efficiencies to achieve over $350 million in savings.

The beneficiaries in this approach are our customers because we are seeking the lowest-cost options. We have a solid record of cost control. In fact, we have been in a position to actually decrease prices to our customers over the past six years. We think our strategy of being a low-cost provider, cutting costs and streamlining our decision making process to take advantage of marketplace opportunities is in sync with where energy markets are headed.

II. Bonneville must adapt to the increasingly competitive energy market.

BPA faces the same competitive issues we face. We encourage them to respond to these competitive pressures. I do want to commend Bonneville for its recent efforts to respond to customer concerns about competition. BPA took seriously questions about a potential price increase in excess of 20 percent and reduced the increase to a more reasonable level without gutting key activities. Bonneville officials are also thinking about how the agency is organized and staffed, and they are looking for other ways to reduce costs and increase efficiency. An example is Bonneville's internal Function-by-Function Review which is intended to streamline the agency's existing processes and work products. Bonneville invited PacifiCorp, along with other customers and interest groups, to participate in the process. We believe it will lead to changes that will make the agency more efficient and urge BPA to continue with similar initiatives in the future. In addition, the recent announcement that 800 positions are to be eliminated at BPA is further evidence that Bonneville's management is facing the challenges head-on.

Reducing costs and controlling prices are clearly first steps toward remaining competitive. But they are not enough. Looking ahead, Bonneville should capitalize on the unique opportunity it has in the regional energy marketplace to provide some of the services it is in the best position to offer, while perhaps letting go of some roles that others may be better positioned to fill.

III. Bonneville should be able to market certain services more aggressively.

We commend BPA for steps they have taken to consider offering selected products to customers. We encourage them to move more aggressively to "unbundle" a wider range of products and services. An "unbundling" of services, such as transmission, storage, load shaping, and others, would add to Bonneville's revenues, enhance efficiencies of resources owned by other power providers, and provide important value to customers.

Key to successfully unbundling Bonneville's service would be opening the agency's transmission system for access by utility and non-utility generators, thus enabling BPA customers to access competitive energy supplies. Bonneville's activities in this area should be done at a pace that will allow regional utilities to capture the benefits of low-cost, efficient generation. Access to utility transmission is opening under the new Energy Policy Act, and Bonneville should adopt the same practices that will be the norm for utilities across the country. Bonneville also should be required to follow the pricing requirements now being developed by the Federal Energy Regulatory Commission for the utility industry broadly.

This move toward unbundling of services should not interfere with Bonneville's chief role in the region: to market the low-cost power available from the existing Federal Columbia River Power System. That role, of course, must continue. But as we look ahead, we should acknowledge that we have maximized the use of those resources. The bigger challenge is how we will operate them efficiently while acquiring the new resources necessary to meet growth in the future.

IV. PacifiCorp supports the concept of tiered rates.

In a more competitive marketplace, BPA's practice of melding costs into one rate structure will no longer be appropriate. Under the melded cost structure, customers who don't need new resources will bear costs associated with resources developed for other parties. Incremental resource costs are masked under a melded-cost system, and the existing BPA resource pool becomes less competitive.

For these reasons, we believe it is time for Bonneville to consider a new pricing structure. Specifically we support a tiered rate structure that differentiates between the cost of the existing resource pool and the cost of new resources.

As we envision it, the existing federal system would be priced at one rate, reflecting its costs, and then allocated to existing customers. Any new acquisitions necessary to meet demand growth would be priced at a higher rate which reflects the cost of the new resource. Those costs should only be borne by customers needing BPA to provide new resources.

Buyers would then be in a position to determine whether the new resource is their best option. This is true for both supply and demand side resources.

The real benefit of such a system is that it would let the marketplace determine whether Bonneville is, in fact, the best developer of resources for the future. It is in the interest of the region's electric customers and the region's economy that resources be developed by the low-cost producer. That could be Bonneville, a utility or an independent power producer. If resources are priced to reflect their incremental costs, buyers will naturally turn to their best option.

If the marketplace determines that Bonneville is not the low-cost producer, the agency will still have an important role as a facilitator of transactions through the shaping, transmission, and other services it can provide. Those services often will be crucial to determining whether power can, in fact, be delivered at the lowest possible cost.

V. Bonneville's residential exchange program rewards utility inefficiency, sending the wrong signal in an increasingly competitive marketplace.

Regional exchange benefits to residential and farm customers of investor-owned utilities are based on the difference between the utility's average system cost and the rate BPA charges its public agency customers. The current methodology has succeeded in making the benefits of the lower cost federal based system available to residential and small farm customers in the Pacific Northwest. However, looking to the future, PacifiCorp believes that the current methodology for calculating the exchange benefit does not reward -- and in fact may penalize -- efficiency efforts by both the utility and Bonneville.

PacifiCorp, for example, has reduced costs, in real terms, over the past six years, with price decreases to most customers. Because Bonneville's costs rose during the same period, the result is that PacifiCorp's costs and BPA's rates are getting closer. If PacifiCorp continues doing a better job of controlling costs than Bonneville, the residential and farm customers of the company are likely to lose their

exchange benefits.

On the other hand, if BPA brings its own costs under better control and holds its costs better than PacifiCorp, it will be required to pay increased residential exchange benefits.

The exchange should be examined to determine how efficiency can be encouraged and rewarded, rather than inadvertently discouraged.

One way to achieve this goal would be for BPA to begin collaborative discussions with its residential exchange customers about an exchange contract settlement. A contract settlement could provide BPA with certainty about future exchange costs, while not penalizing Bonneville or its customers for actions taken to lower costs and increase efficiency. BPA and its customers all could pursue the most economic courses of action without penalty.

VI. Institutions must adapt to the changing marketplace.

We have been very encouraged by the apparent willingness of everybody in the region, including Bonneville, to take a fresh look at the agency's operations. Some creative new options are emerging. For example, we believe the government corporation concept has merit and look forward to exploring that idea with the task force in greater depth in the near future.

We would applaud a model which leads to more efficiency and a streamlining of BPA's decision making. We do believe that a governance structure and accountability to customers, congress and the administration needs to be discussed more fully than it has to date. Also, we believe that Bonneville should establish significant cost reduction goals as part of a changing structure.

It is also appropriate to revisit some of the assumptions that led to the enactment of the 1980 Northwest Power Act, and creation of the many programs we are living with today. For example, we question whether the centralized planning approach envisioned in the Northwest Power Planning Council model remains as valid today, given an increasingly de-centralized

market-driven environment.

VII. The competitive marketplace requires more innovative program implementation.

Before I close, I want to address some other issues that have been raised by the task force: Namely, how Bonneville manages costs related to fish and wildlife protection and conservation.

We recognize that Bonneville faces tremendous environmental pressures mandated by federal statutes. As a Bonneville customer, we expect to pay our fair share -- and as I mentioned earlier, Pacific customers account for one of every ten dollars Bonneville spends. At the same time, we believe the investments Bonneville is making in fish and wildlife programs could be targeted more effectively to meet statutory requirements. Better prioritization could ultimately reduce costs. We also recognize that much of BPA's Fish and Wildlife Program is driven by measures adopted by the Northwest Power Planning Council on behalf of regional fish agencies and tribes. However, the agency appears to be funding far more programs than it needs to, with little evidence that the environmental benefits warrant all of the expenditures. This is an area where Bonneville, its customers, the Council, fish agencies and tribes all need to work together to ensure good results.

We have similar concerns about conservation financing, which also has had a tremendous impact on Bonneville's budget and rates. We have encouraged the agency to look at creative methods for financing conservation programs. We have advocated an approach that more closely assigns the costs of a conservation program to the customer who benefits from it. Spreading conservation costs across a broad section of customers, regardless of who gets the conservation benefit, creates inequities. Conversely, an approach whereby the customer receiving most of the benefits pays most of the costs would minimize rate impacts on other, non-benefitting customers.

Our conservation programs based on this "energy service charge" concept have been well-received by certain market segments, particularly commercial and industrial customers, and might work well for some

customers in the BPA system.

In short, Bonneville still has an opportunity to reduce and manage costs more effectively, by rethinking how it approaches and finances key program areas.

In closing, I want to say, again, that I appreciate the opportunity to present PacifiCorp's views on making Bonneville more competitive. We all have a stake in Bonneville's future, and it is in our region's best interest to help the agency evolve to a role that will serve the region's electric customers best. We hope to be able to continue working with the task force, Bonneville, and other interests in the region as that role evolves in the months and years ahead.

Thank you.

STATEMENT OF WILLIAM K. DRUMMOND

Mr. DRUMMOND. Good morning, Mr. Chairman and members of the task force. My name is Bill Drummond. I am the manager of the Public Power Council. The Public Power Council is as association of Bonneville's publicly and cooperatively owned electric utilities. PPC members all purchase power from Bonneville and account for approximately 50 percent of the agency's revenues

This morning, I would like to address four areas from my written testimony: First, Bonneville competitiveness; second, tiered rates and unbundling; third, resource acquisition; and finally, the national performance review.

There are several aspects to Bonneville competitiveness that I would like to address. First, the Bonneville Project Act, which was the first statute addressing Bonneville as an agency, set the original mission for the agency as encouraging the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor and to prevent the monopolization thereof by limited groups. Without a competitive Bonneville, the original mission of the agency, even as enlarged and enhanced by the Northwest Power Act, will go unfulfilled.

If Bonneville continues on its current path, customers will simply leave the system. They would probably continue to use the transmission system to move power around but Bonneville's days as a resource agency would simply be over. Most utilities are currently examining alternatives to Bonneville's resources and many of the utilities are pursuing alternatives.

A recent public utility bidding process appears to have found several resources that are competitive with Bonneville's current rate. Mr. Hardy talked about the Bonneville rate being about 27 mills. One utility was able to find several generating resources whose first-year cost was less than 30 mills. Those are resources without the attendant risk of fish and wildlife expenditures, repayment acceleration or nuclear decommissioning. Thus, Bonneville as we currently know it could simply disappear, picked over like some carcass for the salvageable parts that utilities can use and that are competitively priced.

The notion of Bonneville going out of business should not be dismissed. It is entirely conceivable that the agency could fade into oblivion—a really great idea whose time came and went.

Second, tiered rates and unbundling—the book on tiered rates is still open with significant potential benefits but also many questions left unanswered. The goals for tiered rates are laudable. First, to send the proper price signal. That would encourage resource development; provide a wider array of choices; show people the true cost of resource acquisition; and reduce pressure on Bonneville's debt cap. It would divorce the cost of Bonneville resource acquisition from the operation and maintenance of the federal base system. There are questions now regarding the cost effectiveness of Bonneville's resource acquisition because they face, of course, their own bureaucracy as well as constraints placed on them by federal law. It would force those who face load growth to pay for the cost of that load growth.

There is a lot of pressure to implement tiered rates, but we must make sure that it works for public power; for example, small sys-

tems particularly with explosive growth. As an example, simply changing the urban growth boundaries for two small mutual systems around Tacoma could cause 100 percent growth in 3 years for those systems. Those sorts of issues have to be addressed. There are many other issues that need to be addressed before tiered rates can be implemented. PBC has a draft set of principles which we have included in the testimony that set the framework for any tiered rates proposal. There are quite a few principles in there. Some of them include no new legislation. We do not believe that legislation is necessary in order to implement tiered rates.

We do need new power sales contracts and residential exchange contracts in order to implement tiered rates.

Both public preference and regional preference must be maintained. New preference customers must be accommodated. Allocations of power must be stable and predictable. We believe that the prices for each tier must be based upon the resources in that tier, not some hypothetical price. Yet to be settled is how the tiered rates would apply to the direct service industries, as well as the residential exchange customers of the investor-owned utilities. Tiered rates hold an interesting promise, but implementation will require considerable work.

Just a few comments on unbundling. First, Bonneville is just now beginning to use its cost accounting system to determine what its products and services cost. Until recently, the accounting system had never been used for that particular purpose. Also, there has been some discussion this morning about cost-based pricing versus value-based pricing. We are extremely concerned about any movement toward value-based pricing, and I would suggest to you that in fact competition will drive Bonneville back to cost-based pricing in any event. Cost allocation has the potential to be completely arbitrary with unbundled products because almost all of Bonneville's products and services are joint products. They are produced as byproducts or in conjunction with other products making it extremely difficult to price them.

Public preference and regional preference to unbundled products must be maintained. I would add that—in response to a question by Chairman DeFazio earlier—I believe that the pooling of utility demands and resources is one way for smaller utilities to gain access to unbundled products and services that larger utilities have access to.

Third, resource acquisition—Bonneville resource acquisition is an essential component to Bonneville becoming more competitive. For example, Bonneville currently has about 450 staff and contractors currently working on resource acquisition. That is simply too many people, perhaps by an order of magnitude. Another example, 40 cents of every conservation dollar—that is, a dollar spent to acquire conservation—goes to some form of Bonneville overhead. That is simply excessive, and it has to come down. The point is that Bonneville has got to change the way it acquires resources. At the same time, the current approach is unworkable in a competitive environment. The new power sales contracts must be sufficiently flexible to enable and encourage independent resource development.

Finally, the national performance review. Just three comments on that issue. One, repayment acceleration is dead on arrival. It is

no different than has been proposed by the Reagan and Bush administrations prior to the current one as you are well aware.

Two, some form of debt buyout of the existing debt is intriguing if two conditions are met. First, rate neutrality; and second, we must have a long-term solution, not simply a year-to-year solution.

Three, the idea of a government corporation is also intriguing, particularly one to help reduce the DOE and OMB regulations that Bonneville faces and to provide Bonneville with greater control over its personnel decisions. But, I would urge that it avoid the issue of governance of the agency. I believe the issue does warrant further study, and we are pursuing that course.

In summary, Bonneville competitiveness is not simply a question. It is an issue of survival—an issue of survival for Bonneville as an agency an issue of survival of the ideals upon which Bonneville was founded, and an issue of survival for the public utilities that depend upon Bonneville for service.

Thank you for the opportunity to testify.

Mr. DEFAZIO. Thank you.

And Mr. Myers, I understand that you made a particular sacrifice to be here today. You had some football tickets, and we appreciate the fact that you chose to come and give testimony and help support our efforts here. It probably would not have been a good game anyway.

Mr. MYERS. Well, that is right. If the schedule had prevailed that was set up 3 or 4 years ago, we would have had the University of Miami playing instead of East Carolina and that might have been a little tougher decision. [Laughter.]

Mr. DEFAZIO. You clearly would have had somebody else here. [Laughter.]

[Prepared statement of Mr. Drummond follows:]

Public Power Council Testimony
before the
Committee on Natural Resources
Bonneville Power Administration Task Force

Eugene City Council Chambers
Eugene, Oregon
September 25, 1993

1. Why is it important for BPA to become more "competitive"? How likely is it that BPA will become a higher cost supplier of energy to the region than other providers? Are there other reasons for BPA to undertake its competitiveness initiative? What principles should guide BPA in this effort?

BPA must remain competitive in order to retain its customer base. If BPA's rates increase disproportionately to alternatives, its customers will seek new power supply options. Bonneville is currently experiencing considerable cost pressures and we do not see these cost pressures declining in the future (e.g., fish and wildlife costs and new resource costs). If BPA's revenues decline as a result of customers leaving, these higher costs will then be spread over a declining customer base.

It is very possible that BPA will become uncompetitive -- the effects of the recent rate increase are a case in point. Many utilities are now looking to reduce their power supply dependance on BPA, including Clark Public Utilities, Tacoma City Light, Seattle City Light, EWEB, and Snohomish PUD. Also, the DSIs, a major segment of BPA's customer base, are reducing production due to the low aluminum prices and rising power rates.

There are other reasons for BPA to undertake its competitiveness initiative. BPA has become too bureaucratic as it has tried to apply a "one size fits all" approach to a myriad of circumstances. Additionally, it has tried to be all things to all people. Delivery time is slowed or stopped by federal requirements, and paralytic analysis and decision-making processes undermine customer service.

Two principles should guide and inform the competitiveness initiatives now being undertaken by Bonneville. The first principle is that Bonneville must work with its customers (those who pay for the programs) to become more businesslike. The second principle should be that all programs must be re-examined for their need, effectiveness, and cost.

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2. **Should BPA adopt tiered rates? If not, why not? If so, how should these rates be structured? If there is a specific model or framework for BPA tiered rates that you support, please describe it in detail. What principles should be used in the development of these rates?**

The issue of whether BPA should adopt a tiered rate structure is still an open question. In recognition of the considerable degree of momentum associated with the concept, we have developed a set of principles to guide the formation of tiered rate proposals. We have undertaken the development of these principles realizing that legal or political impediments may exist that could prevent the implementation of tiered rates. Attachment 1 contains the principles we have developed to date. This is an evolving, dynamic document and there are still issues to be addressed. The key elements embodied in our principles are that tiered rates should not require changes in legislation, that public preference must not be eroded and that the prices charged for the various tiers must be based on actual costs and not on theoretical or modelled results. Ultimately, the basis for any decision on tiered rates must be economics and sound public policy, not politics.

3. **BPA is considering unbundling the services it provides such as transmission, storage, load-shaping, and integration services. What are the potential benefits and drawbacks of unbundling? If BPA pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some BPA services that cannot be unbundled?**

There are potential risks and benefits in unbundling. If BPA adopts tiered rates and/or does not control the rate of increase in its cost of power, utilities and industries in the Northwest will begin to develop their own resources. Some resources will require services from the federal system to be shaped economically to meet Northwest loads. For example, a cogeneration resource may produce power during some months that is surplus to the needs of the purchasing utility. In this case, the utility would probably request "storage" service from BPA or another supplier. Practically speaking, there are probably only a few unbundled services that are absolutely necessary to achieve cost-effective resource integration.

There are some risks as well. First, BPA does not know what individual services cost. Although we understand Bonneville has the cost accounting system in place, it has never been used for this purpose. Unbundling should not be pursued until the appropriate cost accounting system is implemented. Second, cost assignment and thus pricing for these services is likely to be completely arbitrary because they are all "joint products" of the federal system. BPA's unbundled services could simply be used to increase the agency's revenues, without any increase in efficiency. The principle of cost-based pricing for products and services must be maintained. Third, public and regional preference to unbundled services must be retained. Bonneville should not create products to satisfy other markets if they conflict with fulfilling preference obligations in the Northwest. BPA has responsibilities beyond just becoming a "utility business." BPA provides infrastructure throughout the region that benefits everyone in the Northwest.

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4. **How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must BPA do to ensure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection for fish and wildlife? How can the region maintain the benefits of regional coordination and planning if resource acquisition and transmission become more decentralized as a result of tiered rates and unbundling?**

The costs of the fish and wildlife program should be assigned to the first tier, which should include the federal hydro system. These are "externalities" associated with specific resources, and the costs of these programs should be paid for by those using the resources. BPA's statutory requirements to protect fish and wildlife are not defined in terms of unlimited funding, and are not defined specifically in any event, thus there should be no conflict between BPA becoming more competitive and meeting its environmental responsibilities. In fact, if BPA does not become more competitive, its ability to fund any fish and wildlife programs will diminish. The question of how tiered rates relates to the unbundling of products and services has not yet been addressed.

The benefits of regional coordination and planning need not be diminished under a system of tiered rates and unbundled products and services. Regional coordination will probably continue with the Coordination Agreement or some successor arrangement. Coordination will happen in any event through the interconnected nature of the region's electricity system. Decentralized decision-making will not interfere with coordination, because there are economic benefits in coordination that will cause individual decision-making entities to work together. Centralization is not necessary for coordination. Utilities are developing resources now and yet there is no allegation of failure to coordinate. Additionally, resources that are cost-effective under coordinated regional planning will likely remain so with tiered rates and unbundling, as long as open transmission access allows the supply to reach the demand.

5. **Should the variable rate for the DSIs be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this variable rate. What is the current value of reserves of the first quartile of the DSI allocation? What is the current VOR of the second quartile?**

The current VI rate and contract are scheduled to expire in mid-1996. At this point, we have not addressed the possibility of continuing this arrangement. We are working on the question of how tiered rates will apply to the DSIs.

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9. Should the provisions in the power sales contract which allow some utilities to be reimbursed by BPA for lost revenue when a voluntary curtailment is implemented be eliminated? If so, why? If not, why not?

No electric utility is an island. Throughout the nation, all utilities are interconnected by a network of transmission circuits which makes them very dependent upon each other. This is particularly true in the Pacific Northwest, where we have an extensive federal transmission grid. Therefore, if one utility, for whatever reason, does not have adequate resources to meet its load, neighboring utilities must support the deficient utility to prevent serious problems on their own systems. If this support must come from curtailment of loads, then equity demands that the supporting utility receive extra compensation for the adverse effects of curtailment of planed revenues. If the supporting utility is BPA, then the curtailment must come from BPA's utility customers and the extra compensation must flow through to those curtailing utilities who suffered the loss in planned revenues. The provision in the existing contract allowing this to happen must remain.

10. How should the long-term power contracts that BPA is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

PPC and the other BPA customer groups are working on principles for new power sales contracts. It is too early to say what our preferred set of principles will be.

11. It has been suggested that the Residential Exchange Program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

The Residential Exchange Program may reward inefficient utilities since the benefit to utilities exchanging with BPA is based upon the difference between the BPA PF rate and the average system cost of the utility - thus the higher the utility's cost the bigger the exchange benefit. However, we must assume that the state regulatory commissions or the boards of directors of the participating utilities are doing their jobs and keeping the utilities' costs as low as possible.

It may be argued that the Residential Exchange Program provides benefits for utilities that develop generation facilities while it does not provide benefits for all types of conservation programs. There is good reason for this differential treatment of conservation and generation. Certain conservation costs are related to consumer behavior (promotion and advertising) and are not actual hardware costs. These should not be allowed in the calculation of exchangeable costs.

The exchange should be revised to keep track of changes in the utility regulatory arena. Issues include decoupling and the reduction in data availability that results. In addition, utilities should provide Average System Cost (ASC) data to BPA on a timely and

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comprehensive basis. The In Lieu provisions of the contract should be shortened considerably (from 7 years to 1 year) and the deemer provisions should be revised to provide for payments from the utility to BPA when the utility's costs is less than BPA's. Finally, the question of how tiered rates will apply to the residential exchange must be addressed.

12. What part should BPA's existing resource acquisition programs play in BPA's competitiveness initiative, both during a transition period and after BPA has adopted some of the changes it is considering?

PPC believes that BPA's resource acquisition activities will play an important part in the success of its competitiveness initiative. There are many opportunities to streamline the agency's approach to resource acquisition. There are currently 338 Bonneville employees and 117 contractor employees working on various aspects of BPA's resource acquisition activities. In conservation, for example, approximately 40 cents of every dollar spent to acquire the resource is spent on some form of overhead. This is unacceptable! We believe that an approach to conservation that relies upon utility initiative and innovation rather than central planning of conservation programs can significantly reduce the overheads.

During the transition period from current resource acquisition programs to some other approach, PPC believes that we could significantly reduce the amount of program evaluation work that is undertaken. While PPC continues to support "proving" the performance of conservation resources, we believe that the current approach to program evaluation is more directed toward scientific precision than effective implementation. We believe that BPA should no longer determine technical specifications for conservation programs, establish incentive payments and administrative reimbursements, determine reporting requirements, and all other rules for program implementation, then conduct an evaluation and tell its customers that BPA will no longer support their conservation programs because they are not cost-effective. PPC believes that conservation is a viable resource that can be developed very cost-effectively. Our members would like the opportunity to prove that they can accomplish this task.

On the generating resource side, we see several developments that are encouraging. Bonneville recently revised its billing credit policy with an eye toward reducing the administrative burden imposed by a policy that was written when the region had an energy surplus and resource acquisition was the last thing that Bonneville wanted to encourage. Because the policy revisions were undertaken in consultation with customers and the BPA team had a clear message to solve the difficulties of working with the existing policy, the revision effort was largely successful. A new solicitation for 200 aMW was met with interest and negotiations are slated to begin after Bonneville releases its marketing plan in November.

Bonneville must decide what its future role in resource acquisition efforts will be and then consistently develop policies that allow regional utilities to assume a complementary role. If Bonneville chooses in its marketing plan to take a more passive stance in resource

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development, then it must facilitate others taking a more active stance. Bonneville should not simultaneously withdraw from the field of resource development and create obstacles for others. The marketing plan must be consistent with the provisions in the new power sales contracts in order to allow maximum flexibility and efficiency.

Over the long term, PPC believes that if tiered rates become a reality, resource development incentives for utilities may be clearer. We are working to ensure that under any possible tiered rate option, our members will have appropriate price incentives to develop reliable and cost-effective resources, and will have the appropriate policy and contract provisions to allow this to happen.

13. Please provide any other suggestions regarding actions that would make BPA more competitive or cost-effective.

There are three concepts contained in the National Performance Review that have sparked our interest. The first is a section contained in the report which calls for unspecified changes in PMA repayment policy in order to generate an additional $3.6 billion in revenues. This proposal would lead to a substantial Bonneville rate increase, a result which would make Bonneville uncompetitive when added to the recent 16 percent increase in preference utility wholesale rates. Perhaps more ominous is the fact that the Administration is attempting to accomplish this restructuring of debt payment administratively and not through a legislative process. This is in contrast to previous efforts where at least we had the assurance that a change of this magnitude would be fully considered and debated by Congress.

Also contained in the report is an alternate proposal to allow Bonneville to refinance its outstanding appropriated debt through the issuance of long-term bonds. This is an idea we would be interested in exploring with Congress and the Administration. Implementation of this proposal would have to pass two tests from our perspective. First, it must have a neutral rate impact on wholesale rates, and second, any solution must be long-term.

Another proposal would have Bonneville change to government corporation status much like Amtrak and the Tennessee Valley Authority. This could serve to eliminate many of the barriers identified as restraining Bonneville in its efforts to become more efficient. Such a change could be beneficial to the region as long as the current level of influence and cooperation between Bonneville and its customers is preserved. It is contemplated that legislation including the debt buyout and government corporation status proposals will be forthcoming. We are interested in exploring the possibilities as long as the legislation is narrowly focussed on these two elements.

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PPC Principles for Tiered Rates
(Draft of September 6, 1993)

1. Implementation of tiered rates must be accomplished within the structure of existing statutes.

2. Tiered rates require new BPA Power Sales and Residential Exchange Contracts.

3. All existing FBS and contracted resources are subject to public preference, including those that yield unbundled products and services, those used to make sales to the DSIs, and nonfirm energy.

4. New preference customers shall be able, with reasonable notice, to request and receive an allocation of BPA resources, including the FBS, subject to public preference.

5. Regional preference shall be retained.

6. Customers shall be free to make their own resource decisions, subject to applicable laws and regulations.

7. Regional customers must have the option to have BPA meet their loads and load growth.

8. Customer rights to displace purchases from BPA should be clearly defined.

9. Allocations of power must be stable and predictable.

10. Initial allocations of first tier power should be simple, straight-forward and subject to minimal adjustments.

11. Prices for each tier must be based upon the costs of the resources in each tier (only actual, not theoretical, costs)

12. BPA's rate design shall depend on the resource and load characteristics in each tier.

13. BPA's resource acquisitions shall be based upon reasonable notice from the customers.

14. BPA's net revenue volatility shall be minimized.

15. Unbundled services must be available at cost, concurrent with the implementation of tiered rates, subject to public preference.

16. Access to federal transmission must be available at cost, concurrent with implementation of tiered rates, subject to public preference.

17. Utilities should be allowed to combine their allocations of power by assignment to a pool consisting of Northwest preference customers.

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ATTACHMENT 1
PPC Testimony before the
Committee on Natural Resources
BPA Task Force (Page 1 of 5)

Explanation of PPC's Principles for Tiered Rates
(Draft of September 6, 1993)

These notes are provided as a discussion of PPC's "Principles for Tiered Rates". The principles were developed to provide a simple framework for the evaluation of tiered rates alternatives, with this explanation providing more information. We expect that this list will be modified as we move through the tiered rates process. Therefore, this should be seen as a working document.

1. Implementation of tiered rates must be accomplished within the structure of existing statutes.

PPC does not wish to open a legislative "can of worms" in order to implement tiered rates. If tiered rates are to be implemented, it must be within the existing legislative authority.

2. Tiered rates require new BPA Power Sales and Residential Exchange Contracts.

Tiered rates should not be adopted under the current contracts. The anticipated change in the relationship between BPA and its customers that will come as a result of tiered rates will be so sweeping as to require new contracts. BPA's customers cannot respond effectively to tiered rates with the existing contracts, nor can the existing contracts be simply amended. Residential and small farm customers of investor-owned utilities must not be any better off than they are currently ~~receive any additional residential exchange benefits~~ as a result of a move to tiered rates.

3. All ~~existing~~ FBS and contracted resources are subject to public preference, including those that yield unbundled products and services, those used to make sales to the DSIs, and nonfirm energy.

A public utility's right to preference power exists with or without a tiered rates structure. This has regional and national implications. One of the key tests we will use in judging the acceptability of tiered rates is that public power's first right to federal resources is preserved. Thus, when we discuss allocations of the federal resources to customers other than publicly-owned utilities, we must analyze whether this constitutes a transfer of preference rights. Such a transfer cannot be allowed to occur. Initially, public preference applies to existing federal base system resources as defined in the Northwest Power Act. We are also assuming that the word existing implies that federal base system resources, identified in the Act but not in operation, will not be "replaced" with other resources. A question remains regarding future resources that BPA might acquire upon the specific request of individual customers or customer groups: how would public preference apply to these resources? Would the application of public preference differ from the case of existing FBS and contracted resources? These questions mean that the introduction of tiered rates will require a careful re-examination of both the concept and the specific applications of "public preference". (The PPC legal committee is addressing this issue.)

4. New preference customers shall be able, with reasonable notice, to request and receive an allocation of BPA resources, including the FBS, subject to public preference.

New preference customers must be allowed to form and to receive an allocation of federal resources. The adoption of tiered rates does not mean that new public utilities will be shut out from an allocation of BPA resources. Note that this principle is aimed specifically at federal resources that are the subject of Principle #3.

5. Regional preference shall be retained.

Regional preference as embodied in P.L. 88-552 will continue to operate. Thus, sales of BPA power outside the region will occur only after customers in the Pacific Northwest have exercised their "first call" on that power (similar to a right of first refusal). (The PPC legal committee is addressing this issue; Puget's understanding of regional preference is different from the one implied here.)

6. Customers shall be free to make their own resource decisions, subject to applicable laws and regulations.

One of the recognized objectives of tiered rates is to promote resource development by BPA's customers. In order for this to occur customers must be free to make cost-effective resource development decisions without undue interference from BPA or the Regional Council. Adoption of tiered rates must not interfere with the ability of individual customers to make their own resource decisions. There should be no new regulatory oversight due to a shift to tiered rates, although all existing federal, state, and local laws and regulations would continue to apply.

7. Regional publicly owned utility customers must have the option to have BPA meet their loads and load growth.

There are many utilities that will not be inclined to develop their own resources, even under a tiered rate structure, due to such factors as: utility size, load growth or lack thereof, access to capital, or mere disinclination. These utilities must still be able to choose to have BPA meet their current loads and load growth even if tiered rates are adopted. DSIs seeking additional power should work with their local utilities for either utility or third-party service. Service from BPA or a third party would be through the local utility.

8. Customer rights to displace purchases from BPA should be clearly defined.

Customers may choose to displace purchases from BPA by developing resources, making purchases from other utilities, or obtaining other sources of power. In this case, the conditions under which customers may displace these purchases should be clearly defined in the new power sales contracts. This will provide some degree of planning certainty for BPA, the customer making the displacement, and other customers. Displacement rights should be a function of the nature of the costs of the resources being displaced; for example, the contracts could leave some fixed cost responsibility on the customer exercising the displacement right, if BPA has made a new, long-term financial commitment based on the customer's declared intention to purchase.

9. Allocations of power must be stable and predictable.

In order to respond to tiered rates in an orderly manner the allocations of power that would occur as a result of tiered rates must be stable and predictable. If these allocations were to change significantly from year-to-year, or rate case to rate case, the customers would be faced with a "moving target" when it comes to evaluating utility resource development against the alternative of buying from BPA. Some changes may be necessary to initial allocations over time, due to the creation of new preference customers, permanent reductions in DSI loads, or long-term changes in resource capability. These adjustments should be limited, clearly articulated, and made only with proper notice.

10. Initial allocations of first tier power should be simple, straightforward, and subject to minimal adjustments.

This principle applies only to the initial allocations of power to individual customers. We should try to avoid complex allocation formulas that try to take into account every nuance of the load/resource situation, which could lead to endless debate. When the allocation of first tier power is made, simplicity will be important. Tiered rates will be a significant departure from past practice - so simplicity, ease of understanding and communication of the rate will be important. The initial allocations should address the "contracted for and committed to" issue prior to the adoption of tiered rates.

11. Prices for each tier must be based upon the costs of the resources in each tier (only actual, not theoretical, costs)

The price assigned to each tier should track the actual costs of the resources used to serve that tier, and not other kinds of costs. For example, fish and wildlife costs would presumably be assigned to the first tier along with the hydroelectric resources. The costs of the resources in any one tier should not be allowed to migrate to another tier. This will require addressing §7(g) of the Northwest Power Act, which under some conditions allows certain kinds of costs to be spread across all loads. This also means that the costs assigned to the tiers would not be based on a theoretical calculation of marginal cost, but rather on the average total costs of the resources assigned to each tier. This might require additional tiers in the future.

12. BPA's rate design shall depend on the resource and load characteristics in each tier.

Just as the price of each tier should be based on the costs of the resources in each tier, the rate design for that tier should be based upon the load and resource characteristics associated with each tier. This means that each tier may have a different rate design if the load and resource characteristics differ significantly. No rate design issue should be prejudged due to a shift to tiered rates (e.g., classification or the availability charge). Actual billing of purchases could take many forms. Under this principle, rates based on "load characteristics" refers to the usual components of wholesale rate-making, such as capacity, energy, and power factor, and does not include setting rates based on the "value" of end-use loads. If the federal hydro system continues to produce secondary energy, that may be sold on the open market, or used to displace a thermal resource in BPA's second tier (e.g. Tenaska). In any case the revenues from the use of the energy must remain with the resource: e.g., if the energy is used to displace Tenaska, the price of the second tier reflects this displacement, and the price of the first tier is reduced by the corresponding revenue credit.

13. BPA's resource acquisitions shall be based upon reasonable notice from the customers.

BPA's level of resource acquisition activity will be changed by a tiered rate structure, and should be based upon reasonable notice provisions since the customers and BPA will be changing their relative levels of activity with regard to resource development if tiered rates are adopted. BPA's customers will be developing more resources, and BPA will be developing less, if the price signals from tiered rates are effective.

14. BPA's net revenue volatility shall be minimized.

The adoption of tiered rates should not lead to wide swings in BPA's net revenues. If this happens BPA will be likely to respond by increasing its collection of revenues for risk mitigation. The principle refers to net revenues, to emphasize the point that BPA's costs should be tailored to the agency's load obligations.

15. Unbundled services must be available at cost, concurrent with the implementation of tiered rates, subject to public preference.

Customers seeking to develop their own resources, including conservation will require, in some instances, unbundled services. This principle calls for unbundling to occur at the same time as tiered rates are adopted in order to allow customers more flexibility in addressing the customers' changing power supply relationship with BPA. (The PPC legal committee is examining the application of public preference to unbundled services.)

16. Access to federal transmission must be available at cost, concurrent with implementation of tiered rates, subject public preference.

In order to allow customers to respond in the most cost-effective manner to tiered rates, transmission access is critical. BPA's customers can be expected to develop resources from outside their load centers and to purchase power from other utilities and power providers. These require that federal transmission access at cost be available. At the same time, we expect that FERC will work to ensure access to all regional transmission capacity, federal and non-federal, with equitable and reasonable terms and conditions. (The PPC legal committee is examining the role of public preference with respect to the federal transmission system.)

17. Utilities should be allowed to combine their allocations of power by assignment to a pool consisting of Northwest preference customers.

For a number of reasons it may be advantageous for utilities to group together and manage their allocations as a pool instead of as individual utilities. Examples include the benefits of load diversity within the pool and the reduction of administrative costs. The pool then would manage the allocation according to the nature of the pooling agreement. Questions that arise under this approach include: if as a result of diversity the sum of the allocations is greater than the total needs of the pool, can the excess power be sold or used within the pool, or does it automatically revert to BPA? If the excess power can be sold, to whom can it be sold: other preference customers, IOUs, DSIs, outside the region?

STATEMENT OF ROBERT V. MYERS

Mr. MYERS. Good morning. I am Robert V. Myers, senior vice president operations of the Puget Sound Power and Light Company. We are an investor-owned utility with about 800,000 customers in Washington State.

I would like to thank you, Mr. Chairman, and Congressman LaRocco, for this opportunity to present Puget's views on the challenges and opportunities facing the Bonneville Power Administration.

A consistent theme of many of the comments we have heard today and will hear ongoing is the recognition of the challenges facing BPA due to dramatically changing circumstances. All of us here at this table have seen similar challenges, and we have had to respond individually with our own companies with efforts to become more competitive and more cost effective. In response to the specific challenges, Bonneville under the leadership of Administrator Hardy is undertaking an extraordinary effort to reinvent itself, to become more customer focused, cost conscious and flexible. BPA is attempting to change its internal culture and make its products and services more available and usable by its customers.

As you have heard, BPA is undertaking an unprecedented function-by-function review in which BPA is working with the assistance of an advisory group, of which I am a member and several other witnesses here today are also members. This review is on an agency-wide basis and is looking at BPA current operations. I cannot stress too strongly my belief that Administrator Hardy and his management team are doing a superb job under difficult circumstances. As BPA pointed out here today, it has a near-term opportunity to reduce cost and increase its responsiveness. And we are also hearing today a diverse range of interests that are going to be weighed in against and used to judge the outcome of this process. The long-term challenge is to define Bonneville's role in light of these changing circumstances that are facing BPA, the region and the utility industry.

BPA has to promote teamwork in the Northwest. The starting place for defining BPA's role should be the values of the Northwest community, which all utilities in the region serve. Admittedly, there may be a conflict between values. For example, a need for economic and reliable electric service often conflicts with the need for environmental stewardship. Wisely crafted value-based policies, however, can minimize these conflicts.

BPA should not seek to be a competitor, even though we encourage its competitiveness. BPA is more than a utility. First and foremost, BPA is a federal governmental agency. For that reason, Congress and the courts have entrusted it with authority and discretion not granted to other utilities. BPA should not use that authority or discretion to advance its own interest as a utility over the interest of another regional utility and their customers. This is especially important now that BPA has undertaken to reinvent itself to be more competitive. BPA can and should assist the region's utilities in providing an economical and reliable power supply for service to their customers. In this sense, Bonneville does not and should not compete with Northwest utilities but rather should work with them to do what is best for the Northwest. The need for

cooperation among BPA and the region's utilities is accented by the fact that BPA owns most of the major transmission facilities in the region and the utilities in the region rely heavily on that transmission to integrate their loads and resources.

In order to be most efficient and cost effective, BPA must have a clearly defined appropriate role. In other words, BPA should do what it does at least-cost and not do what others can do as well or better perhaps at a lower cost than Bonneville could. For example, the risks of investing in conservation and the small generating projects envisioned for the region can be assumed by individual utilities or groups of utilities. As BPA recognized in its written statement to this task force, greater benefits will accrue to the region where BPA's customers can expand the supply of valuable services or provide the services at lower cost or more efficiently than BPA.

In any event, they should continue to assist regional utilities in transmission and other activities for which BPA and its resources are uniquely suited. This includes exploring a wide range of options for increasing opportunities for regional utilities to participate in things like transmission projects. A good example of this approach is BPA's offering of non-federal participation in the Third AC line of the Pacific Northwest-Pacific Southwest Intertie.

We believe that tiered BPA power rates represent a promising and challenging prospect. Properly designed tiered rates for BPA firm wholesale power sales that reflect the cost of developing new resources can encourage conservation and help ensure that BPA and BPA's customers receive appropriate price signals. If BPA's rates for additional power sales are based on the cost of providing that power, BPA will not be faced with meeting demand for its power stimulated by rates that mask the cost associated with new resources.

However, there are many issues that remain and you have heard a number of those expressed already that have to be resolved with respect to the design and implementation of tiered BPA rates. The promise is there, and we are confident that BPA working with its customers and other interest groups exploring these issues will come up with a reasonable solution.

BPA's services should be made available on an unbundled basis at cost-based rates, and I emphasis cost-based rates. BPA has appropriately recognized that it should provide unbundled services tailored to its customers' needs. Unbundled services should promote efficient BPA operations and help ensure that BPA's customers pay for only those BPA services that they need and use.

Unbundling of BPA's services should emphasize separately pricing those services for which BPA has incurred or incurs material and direct operating or capital cost to provide. This does not require subdividing BPA's services into every identifiable element which would be difficult and costly to administer and unnecessarily complex.

The rates for BPA's firm power and other services must be cost-based in order to avoid cross-subsidization of one customer class by another. Such cross-subsidies are unfair. They also send erroneous price signals that promote inefficient outcomes. Unbundling should not be seen or used by BPA as a vehicle for charging what the mar-

ket will bear for one service in order to subsidize another service. Bonneville, for example, should not use its monopoly power in transmission or other markets to subsidize Bonneville's firm power service.

Finally, the purpose of the BPA residential exchange was to extend the benefits of the federal system to all residential customers in the region. The residential exchange does not provide an incentive for investor-owned utilities to operate less efficiently. The benefits of the exchange are available to the residential and small farm loads of any utility in the region, public or investor-owned, and each utility has a strong incentive to keep its costs down because none of its commercial or industrial loads receive any benefits from the residential exchange.

Any suggestion that the residential exchange provides an incentive for an investor-owned utility to operate less efficiently would be erroneous and unsupported by the facts. In any event, investor-owned utilities in the region do involve themselves in least-cost planning and their costs, plans and actions are subject to extensive review by state public service commissions.

Thank you for the opportunity to appear before this task force.

Mr. DEFAZIO. Thank you, Mr. Myers.

Mr. Reiten.

[Prepared statement of Mr. Myers follows:]

STATEMENT OF

PUGET SOUND POWER & LIGHT COMPANY

BEFORE

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON NATURAL RESOURCES
BPA TASK FORCE

Eugene, Oregon

September 25, 1993

September 25, 1993

SUMMARY OF STATEMENT
OF
PUGET SOUND POWER & LIGHT COMPANY

BPA is facing dramatically changing circumstances and in response is undertaking an extraordinary effort to reinvent itself. BPA Administrator Randy Hardy and his management team are doing a superb job under difficult circumstances.

BPA should promote teamwork in the Northwest and should not seek to be a "competitor." BPA should seek to be efficient and cost-effective but must never seek to use its authority or discretion to advance its interest as a utility at the expense of the interest of another utility. In order to be efficient and cost-effective, BPA must have a clearly defined and appropriate role that focuses on those activities for which it is best suited.

Tiered BPA firm power rates is a promising and challenging prospect and can encourage conservation and prudent resource development and utilization decisions. BPA services should be made available on an unbundled basis at cost-based rates, without cross-subsidization of one customer class by the other.

September 25, 1993

STATEMENT
OF
PUGET SOUND POWER & LIGHT COMPANY

I. INTRODUCTION

This Statement is submitted on behalf of Puget Sound Power & Light Company ("Puget"), an investor-owned electric utility which serves about 800,000 customers within a 4,500 square mile service area in eight counties in Western Washington and one county in Central Washington. Puget appreciates the opportunity to provide comments on the challenges and opportunities facing BPA.

II. BPA RESPONDS TO CHALLENGES

The circumstances facing BPA are changing dramatically--the deregulation of power supply, transmission access, the disappearance of the regional electricity surplus of the 1980s, increased fish and wildlife mitigation and enhancement efforts, closure of the Trojan Nuclear Project, federal fiscal constraints and adverse hydroelectric generating conditions in the region.

In response to the challenges posed, BPA under the leadership of Administrator Randy Hardy is undertaking an extraordinary effort to reinvent itself--to become more customer-focused, cost conscious and flexible. BPA is attempting to change its internal culture and make its

products and services more available and usable by its customers.

For example, BPA is undertaking an unprecedented Function-by-Function Review, in which BPA is working with the assistance of an advisory group of customers and key interest leaders to evaluate, on an agency-wide basis, BPA's current operations. This Function-by-Function Review should enhance BPA's ability to track its expenditures and help to ensure that BPA's resources are efficiently and effectively employed.

Puget cannot stress too strongly that Administrator Hardy and his management team are doing a superb job under difficult circumstances. BPA is already planning an immediate reduction in administrative costs. The Administrator has taken this decisive action in response to BPA's near-term financial requirements. However, at the same time, he has wisely made clear that BPA's long-term goals will not be compromised.

The long-term challenge is to define BPA's role in light of the changing circumstances facing BPA, the region and the utility industry and to ensure that BPA is structured so as to facilitate the cost effective performance of that role even as the leadership of BPA changes over time.

III. FUNDAMENTAL PRINCIPLES AND OBJECTIVES

A. BPA Should Promote Teamwork in the Northwest

The starting place for defining BPA's role should be the values of the Northwest community which all the utilities in the region serve. Admittedly, there may be a conflict between

values; for example, the need for economic and reliable electric service may conflict with the need for environmental stewardship. However, wisely crafted value-based policies can minimize these conflicts. BPA will be able to sustain broad support in the future if BPA does not favor the interests of one regional customer group over those of another and if BPA balances the responsibilities it has to its customers with those it has to fish and wildlife and the environment.

Because BPA has a region-wide presence and responsibilities to a broad range of constituencies, BPA should act as a catalyst to promote cooperation and teamwork. BPA's role is most effective as a catalyst rather than as a unilateral actor. This requires BPA to take a view which considers the impact of its actions and policies on the entire region.

One of the objectives of the Northwest Power Act is the protection, mitigation and enhancement of fish and wildlife resources while providing the Pacific Northwest with an adequate, efficient, economical and reliable power supply. BPA should work with the Northwest Power Planning Council, utilities, fish and wildlife agencies and others to meet this objective.

B. BPA Should Not Seek to Be a "Competitor"

BPA is more than a utility. First and foremost, BPA is a federal governmental agency. For that reason, Congress and the courts have entrusted it with authority and discretion not

granted to other utilities. BPA must never use that authority or discretion to advance its interest as a utility at the expense of the interest of another regional utility and its customers. This is especially important now that BPA has undertaken to reinvent itself to be more "competitive."

BPA can and should assist the region's utilities in providing adequate, efficient, economical and reliable power supply for service to their customers. In this sense, Bonneville does not and should not "compete" with Northwest utilities but rather should work with them to do what is best for the Northwest.[1] BPA policies which are truly fair to all can play a major role in this worthy goal.

The need for cooperation among BPA and the region's utilities is accented by the fact that BPA owns most of the major transmission facilities in the region, and the utilities in the region rely heavily on that transmission to integrate their loads and resources.[2]

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[1]This means, for example, that, to the extent permitted by statutory requirements, BPA should treat utilities in the region equally and not favor one customer class or service over another.

[2]The Pacific Northwest has a unique history with respect to transmission. As recognized in the Conference Report for the National Energy Policy Act of 1992, BPA historically

> has built most of the intraregional bulk transmission facilities in the Pacific Northwest. This was done on the basis of a regional consensus and the understanding that BPA would make these transmission facilities available for transmission of power for BPA's power and transmission customers located in the Pacific Northwest.

C. BPA Should Seek to Be Efficient and Cost-Effective

Rather than compete with its constituencies, BPA should seek to perform its role in an efficient and cost-effective manner. BPA has recognized the need to be more cost-effective and is undertaking the Function-by-Function Review discussed above. Other aspects of BPA's effort to become more cost-effective are the "unbundling" of various BPA services and tiered rates, which are discussed below.

In order to be most efficient and cost effective, BPA must have a clearly defined, appropriate role. In other words, BPA should do what it does at least cost and not do what others can do as well or better. For example, the risks of investing in conservation and the small generating projects envisioned for the region can be assumed by individual utilities or groups of utilities. BPA need not acquire those resources in order to make their financing possible.[3] BPA's administrative costs can be reduced accordingly.

> The utilities of the Pacific Northwest have relied and continue to rely on that transmission. . . .

Conference Report to Accompany H.R. 776, 102nd Congress, 2nd Session, H. Rep. 102-1018 (October 5, 1992), p. 389. BPA's key role in providing transmission for Northwest utilities is reflected in Section 722 of the Act which amends Section 212 of the Federal Power Act to include subsection (i), "Laws Applicable to Federal Columbia River Transmission System."

[3]When the Northwest Power Act was adopted in 1980, common wisdom among resource planners contemplated a major role for large, centrally located generating stations in which multiple participants would each share a small percentage of the output. The ability to offer these shares to BPA

One of the cornerstones of the Northwest Power Act was the authorization of BPA to acquire the output of major resources and make it available to the region's utilities to serve their customers' needs. It was contemplated that BPA and the region's utilities would work together in these major resource acquisitions. (This is reflected for example in section 6(m) of the Northwest Power Act that specifically contemplates that the region's electric utilities will have an opportunity to participate in major resource acquisitions by BPA.) Although conservation and small generating projects are assuming a significant role in the region, the objectives of the Northwest Power Act with respect to BPA's role in the acquisition of major resources should not be abandoned, if and to the extent major resources acquisitions are undertaken.

BPA should in any event continue to assist utilities in transmission and other activities for which BPA and its resources are uniquely suited. BPA should for example explore a wide range of options for increasing opportunities for regional utilities to participate in transmission projects. A good example of this approach is BPA's offering of non-Federal

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would help to spread the risk of such a project. One of BPA's roles upon adoption of the Northwest Power Act was generally seen to be spreading the risk of such large projects and also providing transmission and load factoring to enhance the usefulness of new resources and also promoting conservation. However, the implementation of the Public Utility Regulatory Policies Act ("PURPA"), the advent of independent power producers and other developments encouraging acquisition of a diversity of generating resources and conservation have significantly changed the utility industry.

participation in the Third AC line of the Pacific Northwest-Pacific Southwest Intertie.

BPA also has a major responsibility with respect to fish and wildlife resources impacted by the Federal hydroelectric system. The costs involved are very large and growing even larger. That makes it imperative that BPA ensure that its expenditures are achieving real benefits for fish and wildlife. BPA should insist that any fish or wildlife program funded by it include at the outset specific, measurable objectives. Additionally, it should insist that there be established at the outset how and when program performance will be measured against those objectives. Finally, BPA should insist that when programs are not meeting their objectives they should be stopped or changed so the dollars can be redeployed in ways that will provide real benefits for fish and wildlife. The clear responsibility to fish and wildlife resources is not satisfied just by spending dollars. The challenge is to make sure that the dollars are spent in a way that really benefits fish and wildlife.

In short, BPA can continue to improve its efficiency and cost-effectiveness by shifting its focus toward a clearly defined goal that emphasizes those activities for which it is best suited and by helping to ensure that its fishery and other environmental programs produce the desired result cost-effectively.

D. Tiered BPA Power Rates Is a Promising and Challenging Prospect

Properly designed tiered rates for BPA firm wholesale power sales that reflect the costs of developing new resources can play a significant role in encouraging conservation and ensuring that BPA and BPA's customers receive appropriate "price signals." If BPA's rates for additional power sales are based on the cost of providing that power, BPA's customers will have an economic choice among conservation, purchasing BPA power or acquiring power elsewhere--and BPA will not be faced with meeting demand for its power stimulated by rates that mask the costs associated with new resources. Tiered BPA firm wholesale power rates can and should provide an incentive for conservation.

However, there are many issues that remain to be resolved with respect to the design and implementation of tiered BPA rates.[4] The promise is there, and we are confident that BPA

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[4]It should be noted that tiered rates for BPA's firm power sales to its customers need not be particularly complicated. (It is for example not necessary to allocate particular resources to particular rate tiers.) Amounts of power sold at the "first tier" rate to any public utility could be established based on its historical period usage, and that utility could be permitted to purchase that amount of power at the tier 1 rate to the extent such power is needed to meet its previously existing firm retail load. The first-tier amount and rate design would have to be established and fixed by contract to provide sufficient assurance that a BPA customer's investments in response to tiered rate signals or incentives would not be wasted. In any tiered rate proposal, the cost of the federal hydroelectric generating resources would include the cost of fish and wildlife measures associated with those resources; accordingly, tiered rates should not diminish BPA's ability to protect fish and wildlife.

will work with its customers and other interested groups to help ensure that these issues are fully explored.

E. BPA's Services Should Be Made Available on an Unbundled Basis at Cost-Based Rates

BPA has appropriately recognized that its historic approach of bundling many of its services together into one should be replaced by a fundamentally different approach--providing unbundled services tailored to meet its customers' needs.

Unbundled BPA services should promote efficient BPA operations and help ensure that BPA's customers pay for only those BPA services that they need and use. Unbundling of BPA's services should emphasize separately pricing those services for which BPA has incurred or incurs material and direct operating or capital costs to provide such services.[5] This does not require subdividing BPA's services into every identifiable element, which would be difficult and costly to administer and unnecessarily complex.

It is of fundamental importance that the rates for BPA's firm power and other services be cost-based to avoid cross-subsidization of one customer class by another. Such cross-subsidies are unfair. They also send erroneous price signals that promote inefficient outcomes. Unbundling should not be

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[5]For example, BPA's transforming power (whether Federal power sold by Bonneville or non-Federal power transmitted by Bonneville) for delivery at low voltages imposes material costs on BPA that should be reflected in the rate BPA charges for such service.

seen or used by BPA as a vehicle for charging "what the market will bear" for one service in order to subsidize another service. BPA should not use its monopoly power in transmission or other markets to subsidize BPA's firm power service.

F. Direct Service Industries Can and Should Provide Important Reserves Under Their BPA Power Sales Contracts

Under Section 5(d) of the Northwest Power Act, sales to the direct service industrial (DSI) customers of BPA are to provide a portion of BPA's reserves for firm power loads within the region.[6] The reserves provided by the DSIs encompass short-term stability reserves (under which a DSI load in its entirety may be interrupted on little or no notice when necessary to preserve system integrity and to protect against unanticipated system outages) and longer-term energy reserves (under which various quartiles of a DSI load may be interrupted for various reasons related to the absence of hydroelectric generation or the failure of resources to be available and operate as planned). The region has experienced low streamflows this year, and the first quartile of BPA service to DSI loads has been interrupted for a significant

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[6]"Reserves" under the Northwest Power Act are "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers . . . ." Northwest Power Act § 3(17), 16 U.S.C. § 839a(17).

period. This interruption has reduced deliveries of BPA power to DSI loads at a time when power has been quite valuable.

It is clear that the DSI reserves, including the first quartile, are of considerable value to BPA (although the value at any particular time may be difficult to calculate with precision).

The reserves provided by DSI loads largely reflect the unique capability of the DSI loads to accommodate interruption for various lengths of time with relatively few adverse impacts as compared with interruption of a utility's retail load.[7]

Further, DSI loads do not peak in the wintertime as do Northwest utility loads. The ability to reduce hydroelectric generation (due to minimum streamflow constraints) and thermal generation during periods of relatively low demand is limited; DSI loads help to prevent waste of generation during periods of relatively low demand.

The benefits that the DSI loads can bring to BPA's operations can and should continue to be reflected in BPA's power sales contracts with DSIs.

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[7]Some DSI loads even have the capability of routinely using more energy during the night (when BPA's other loads are relatively low) than during the day. Such "shaping" of some DSI load into the nighttime hours can reduce BPA's costs, and incentives should be considered to encourage this "shaping" of DSI load. Other modifications of DSI facilities or operations to provide BPA with additional reserves may be available and cost-effective, if reserves are appropriately valued.

G. The Purpose of the BPA Residential Exchange Was to Extend the Benefits of the Federal System to All Residential Customers in the Region

When the Northwest Power Act was enacted, it provided for Residential Purchase and Sale Agreements ("RPSAs") to address a very real and valid concern. During the power shortages of the mid-1970s, investor-owned public utilities lost their direct access to federal power and were faced with construction of their own resources. This threatened increasing disparities between the rates paid by residential customers of investor-owned public utilities and the rates paid by residential customers of publicly owned utilities who continued to have access to the Federal system with its low cost hydropower. The purpose of the RPSAs was to extend to the residential customers of all utilities in the region the opportunity to share in the benefits of the Federal system, and to prevent the residential customers of utilities from being penalized financially as a result of their development of resources. Thus, RPSAs are intended to provide benefits to publicly owned and investor-owned utilities alike.

The RPSAs do not provide an incentive for investor-owned utilities to operate less efficiently. The benefits of the exchange are available to the residential and small farm loads of any utility in the region, and each utility has a strong incentive to keep its cost down because none of its commercial or industrial loads receive any benefits from the residential exchange. Any suggestion that the RPSA's provide an incentive

for an investor-owned utility to operate less efficiently would be erroneous and unsupported by the facts. In any event, investor-owned utilities in the region do least-cost planning and their costs and plans are subject to extensive review by state public service commissions.

If the RPSAs are revised, it is important to note that several categories of costs have been previously excluded from exchangeable costs. Such exclusion does not appear to be justified at this time. For example, BPA has limited the conservation costs that may be exchanged with BPA; accordingly, some of the utility's costs incurred to develop conservation are in essence not treated as exchangeable resources, which fails to encourage conservation and efficiency in the use of electric power as envisioned by Congress in enacting the Northwest Power Act. All of BPA's production and transmission costs are included in BPA's costs, but some of the exchanging utility's production and transmission costs have been excluded by BPA. If the RPSA's are revised, BPA should return to the original principle that all production and transmission costs of the exchanging utility are exchanged, just as all of BPA's production and transmission costs are exchanged.

Thank you for this opportunity to provide comments.

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STATEMENT OF RICHARD G. REITEN

Mr. REITEN. Mr. Chairman, on behalf of Portland General Electric and 600,000 plus customers, I want to thank you and the congressman and the task force for convening the hearing and giving us an opportunity to testify today.

Our company, PGE, is one of BPA's largest customers. We purchase energy, energy capacity and transmission services in the magnitude of $50–$60 million a year. We have borne the third largest share of the current rate increase that BPA has made. That impact is approximately $30 million on PGE's customers.

We share with BPA a common interest in the timely and cost-effective decommissioning of the Trojan Nuclear Plant, as well as the operation of the Pacific Northwest Intertie.

While we do a lot of business with BPA, we also are in a sense a competitor. Not so much for customers but for energy. The region is in deficit with respect to any energy surpluses and virtually every utility in the region is in the same situation. We now compete with BPA for energy in the secondary energy markets. So for all practical purposes, the size of BPA and the fact that there is no longer a surplus in the region, we meet them in a competitive situation in the secondary energy markets. Many times because of their size, they are the benchmark pricers of secondary energy for all utilities, public and private in the region in that market.

I think it is important to understand that BPA is the hub of a competitive market today. While their role is to be a cost-effective transmitter of energy and an integrator of new and old power supplies, they are in a very strong and instrumental position. They have clearly what Mr. Myers just described as near monopoly power in the transmission area and they can inhibit, or enhance, or tax their customers and others as a result of their policies and their pricing.

With respect to the residential exchange and access to the federal hydroelectric system for our customers and other investor-owned utilities, as was just explained, we do that through the residential exchange. It is a critically important program for all of Oregon's electric customers and certainly ours, which are the majority of the customers in Oregon. As a result of that, we in our relationships with Bonneville believe that a healthy, well-managed, strong Bonneville is best for our company, for our customers and for the region.

It is clear that all of us in this business, whether we are public or private, small or large, are facing pressures of increased competition. To compete, we are all reducing costs and striving to deliver higher quality and more reliable products.

In our view, government agencies should be placed in the same marketplace orientation and face the same pressures. Contrary to what some believe, competition within the electric industry did not descend in the last 12 or 18 months but basically has been escalating over the past 5 years. And any monopoly that we had as an industry, electric utilities, public and private, in power generation is eroding and being replaced by independent power projects, non-utility generators, demand-side management, a whole variety of programs. Half of the new energy capacity in this country is coming from those sources.

Now the transmission system monopolies for bulk power sales that we just described that BPA has, and to some extent, some of the private utilities are better positioned than others, like ourselves. That is also disappearing. That comes as a result of the aggressive legislation in the 1992 Energy Policy Act that is really opening up wholesale power transactions and good action by BPA and others to open up some of their utility monopoly-type positions on interstate transmission through this Act and through the Third AC participation that was described earlier.

PGE has had a variety of experiences, both good and bad, with the forces of competition. And through these experiences, we have come to the conclusion that they are driven by two forces today and that is what affects the ultimate price paid by energy consumers.

The first is the fact there is increased competition. It is driving prices down, requiring all of us to be better managers and make our organizations most cost efficient. All organizations across the country in this business are addressing these issues.

The second force is the increased cost of doing business, which has required ratepayer funds, public and private, to be applied to environmental compliance activities, fish and wildlife protection programs, increased taxes, user fees, permits and a variety of regulatory requirements.

This situation places us energy providers on a collision course with a competitive marketplace. On one side, we face higher costs mandated by social and environmental expectations; on the other side, we are squeezed by a reduced supply in the region and a demand for lower prices and more competition as a result of federal policy in that regard.

Bonneville is caught in the same identical situation. Some of their customers want access to lower-cost, independent power that bears no social costs of fish and wildlife mitigation and a variety of other things. It is lower but it does not have the same costs that Bonneville had to undertake to do the programs that are both mandated by the regional council and federal policy and their own will to provide the right kind of protection of our environment in the Pacific Northwest.

While these forces are at work, we, the managers of the energy corporations, are trying to deal with it. And our costs are not going to go away unless we make them go away. And we are going to have to manage both sides of this difficult equation. It makes it very tough. In other words, private and public utilities are sharing the same issues today for the energy needs of our customers and trying to deal with the public policy issues of good stewardship of our region and our rivers and our fish.

I said a moment ago that we had good and bad experiences with competition. You know, investor-owned utilities can share their war stories. We have our own. It is not easy telling 51,000 stockholders they will not be paid their full dividends in 1989 and they were reduced. It is not easy completing a year-long internal management review and releasing 10 percent of our employees, approximately 300, in 1990. It is not easy closing your largest generating plant and laying off 1,000 highly trained, educated employees in January of this year. A nuclear plant that comprised 50 percent of the tax base of a rural county and 60 percent of the funding for

the schools in that county. And in 6 months, we have reduced $10 million of our A&G costs associated with the Trojan Nuclear Plant in our corporate costs. But to stay competitive, we have to change as a company.

It has been said that God made the world round so that we would not be able to see too far down the road. If that is true, we have no alternative but to prepare for the future by learning from the past. If there is anything that PGE can share from its past experiences it is this: Review your options carefully; be willing to make the difficult decisions; act quickly and decisively. In that regard, Bonneville needs the opportunity to act quickly and decisively. If they do not, you have heard that they will be non-competitive. I do not believe anybody is going to leave. The true fact of the matter, a 20,000 megawatt hydroelectric system with the cost they have, they are going to depend upon it. But clearly fundamental changes need to be made. Bonneville's management is addressing those fundamental changes, but it is important that they move quickly and decisively as I said. I think it is important that they have the opportunity to do that.

Just a couple of short comments with respect to the issues requested that we comment on. First, we think it is possible that a government corporation could provide Bonneville with some financial flexibility that they do not now have. We think that should be studied.

Second, we think that the constraints from the federal personnel requirements and others are overly restrictive and that they ought to be given some freedom because this management team at Bonneville has shown both the will and the ability to make the changes and to address them immediately.

And in the end, the ultimate objective is to bring about a corporation or an entity that exists today under the oversight of the Northwest Power Act and the other Federal Government oversight that they have to deal with. I believe that these laws and the present oversight are in fact working. So Bonneville, to conclude, needs the opportunity to make the management changes, realign the organization, address tiered rates, unbundling and bring about the competitive nature that they are talking about. Administrator Hardy and his management team can do that and we support them.

Thank you for this opportunity.

Mr. DEFAZIO. Thank you.

Mr. Crisson.

[Prepared statement of Mr. Reiten follows:]

STATEMENT OF

RICHARD G. REITEN, PRESIDENT, PORTLAND GENERAL ELECTRIC

before the

Bonneville Power Administration Task Force
Committee on Natural Resources
U.S. House of Representatives
Chair, The Honorable Peter DeFazio

Eugene City Council Chambers
777 Pearl Street
Eugene, Oregon
Saturday, September 25, 1993
9:30 a.m. o'clock

I. INTRODUCTION

On behalf of Portland General Electric (PGE) and over 600,000 customers, I want to thank Congressman DeFazio and the Natural Resources Committee for convening this hearing of the BPA Task Force.

PGE is one of BPA's largest customers purchasing real energy, energy capacity and transmission services in the magnitude of 50 to 60 million dollars a year. We have borne the third largest share of the recent rate increase. In fact, it can be said that the largest Oregon impact from BPA's rate hike is on PGE customers, an increase of about $30 million.

BPA and PGE share a common interest in the timely and cost effective decommissioning of the Trojan Nuclear Power Plant, as well as in the operation of the Pacific Northwest Intertie.

While PGE does a lot of business with BPA, we are also competitors -- not so much for customers, but for energy. Since the region exhausted it's energy surplus, PGE, and virtually every other utility in this region, now compete with BPA to purchase power in the secondary markets.

For all practical purposes, BPA is so large that at many times during the year they establish the benchmark price for secondary power.

It is important to understand that BPA is the hub of a competitive market in which their role is to be a cost effective transmitter and integrator of new and old power supplies. And BPA presently has monopoly power that can be used to inhibit, or tax, the new competitive power markets.

Finally, economic access to the Federal Hydroelectric System for our customers, and those of other IOUs, is through the residential exchange. As you know, this is a critically important program that impacts the majority of Oregon's electric customers, customers that

are served by PGE.

For all of these reasons, PGE has always believed that a healthy Bonneville Power Administration is best for the Pacific Northwest, for PGE and for our customers.

II. INCREASED COMPETITION VS INCREASED COST OF DOING BUSINESS.

Mr. Chairman, all businesses in this country, whether they are public or private; small or large; domestic or international, are facing the pressure of increased competition. To compete, we are all reducing costs and striving to deliver higher quality and more reliable products.

In our view, government agencies should be placed in the same marketplace orientation and face the same pressures.

Contrary to what some believe, competition within the electric utility industry did not just descend upon the Pacific Northwest in the past eighteen months. Competition has been escalating within the region -- as it has around the nation -- for the past five years.

The monopoly that utilities had in power generation has been replaced by Independent Power Projects (IPPs). Last year over half of the new energy capacity in the country came from IPPs.

The transmission system monopolies for bulk power sales that utilities enjoyed are also disappearing. This comes as a result of aggressive legislation approved by Congress last year to open up transmission systems to wholesale power transactions and to facilitate non-utility generation.

At PGE we have had a variety of experiences -- both good and bad -- with these forces of competition, some of which I will get into in a moment.

Through our experiences, we have come to the conclusion that competition is driven by two forces that affect the ultimate price paid by energy customers.

The first is the force of increased competition that has driven prices down and required companies to become better managers and more efficient organizations. Almost all energy producers are addressing these issues.

The second force is the increased cost of doing business which has required ratepayer funds to be applied to environmental compliance activities, fish and wildlife protection programs, increased taxes, user fees, permits and other regulatory requirements.

This situation has placed all energy providers on a collision course with a competitive marketplace. On one side, we face higher costs mandated by social and environmental expectations. And on the other side, we are squeezed by a reduced supply, a demand for lower prices and more competition imposed by both market forces and the moves toward deregulation contained in the 1992 National Energy Policy Act.

While it is popular to talk about the forces of competition, energy customers must know that what they will eventually pay for energy is the cumulative affects of competition and increased regulation. Utilities are not going to make these costs go away, so our challenge is to manage both sides of this difficult equation.

The ability to make the tough decisions in this difficult environment will make the difference between success and failure -- for both public and private energy providers.

At the same time, we must share on a broader scale in the competitive position of our region and the resulting economic impact on employment and quality of life for the citizens of the Northwest. In other words, both private and public utilities must increasingly share the responsibilities for the energy needs and public policy issues of the region.

III. THE NEED TO CHANGE... QUICKLY

Mr. Chairman, as I said a moment ago, PGE has had a variety of experiences with competition -- both good and bad.

Other representatives of the investor-owned utility industry can share their war stories, but let me say from PGE's experience... it is not easy telling more than 51,000 stockholders that they will not be paid their full dividends, as PGE did in 1989.

It is not easy completing a year-long internal management review and releasing 10 percent of our employees, as we did in 1991.

And it is not easy closing your largest generating plant and laying off nearly 1000 highly trained, highly educated and highly paid workers in January of this year -- a nuclear plant that comprised 50 percent of the tax base of a rural county and 60 percent of the funding for its schools.

But to stay competitive you must change.

It has been said that "God made the world round so that we would never be able to see too far down the road." If that's true, then we have no alternative but to prepare for the future by learning from the past.

If there is anything PGE can share from its past experiences it is this:

> **Review your options carefully, but be willing to make the difficult decisions as quickly and decisively as possible.**

It is our concern that the important changes needed to be made at Bonneville will not be implemented in time to avoid the collision I talked about earlier, or that management will not

be allowed to make the necessary changes due to restrictive policies.

To emphasize this point, I believe that -- like the health care system in this country which is dramatically effecting company costs and the financial stability of so many families -- failing to make changes at BPA is by far the worst of all alternatives for the region.

IV. IMPLEMENTING CHANGE

Generally speaking, decisions of the magnitude I mentioned here have two somewhat distinct paths. The first is the analysis: studying your options, making assumptions, running various scenarios.

But perhaps the most difficult part is actually implementing the decision once it is made. When you are talking about changes as fundamental as those currently contemplated at Bonneville, it is our experience that the strategy and timing for implementing the decision is as important, if not more important, than the decision itself. Management needs the ability to move swiftly and decisively.

V. SPECIFIC RECOMMENDATIONS FOR BONNEVILLE

As a federal agency, BPA is going to have a set of challenges quite different from that of private industry as they define their mission and attempt to implement these changes within the organization.

Mr. Chairman, at this point I'd like to quickly go through a few key issues confronting Bonneville, and based on our experiences, provide some general comments and recommendations.

BPA Personnel Requirments and Repayment Reform:

Over the years, there have been a number of proposals to transform BPA into a different kind of entity. The most recent being a proposal to create an independent government corporation.

Our view is that the focus needs to be first, and foremost, on creating an environment for BPA in which it can be quicker on its feet and more responsive to the market.

At a minimum, I would argue that Secretary O'Leary and the Congress need to help BPA deal with the constraints imposed by federal personnel requirements and other polices that are restrictive and that might impede their recently announced downsizing.

In conjunction with changes in personnel requirments, it may also be advantageous to the region to allow BPA to swap old U.S. Treasury debt with private financing.

These changes may not lead to the immediate cost savings some interest groups are looking

for, but they will make BPA more agile and more competitive.

In the end, that should be the ultimate objective. And if turning BPA into an independent government corporation is the best way to meet that objective, then it ought to be given serious consideration.

Northwest Power Planning Council and Congressional Oversight:

Now let me say a few words about what shouldn't change. I don't want my comments on internal changes to also extend to changes in BPA's "governance" by the Power Planning Council and Congress.

Some tinkering may be warranted, but frankly the investor-owned utility industry has tried to get some relief from expensive and extreme levels of oversight by the SEC, NRC, FERC, EPA, USDOE, not to mention DEQ, EFSC, ODOE and so on.

I am not sanguine that changes in reporting requirements will translate into actual savings or quicker management decisions. We believe what needs to be addressed can be done under present reporting relationships and with the Northwest Power Act left intact.

Tiered Rates:

BPA and the Congress are wise to look at tiered rates as a means of sending the right price signals to energy users about the true cost of developing new energy resources. There are many versions of tiered rates and many delicate issues that need to be resolved.

But isn't it the goal of "competition" to let true market prices help dictate the choices made by energy users? If implemented, I believe that some form of tiered rates would help alleviate the political pressure in Washington for refinancing BPA's debt. It would also send the proper signals to Bonneville's customers in the selection of new resources and conservation programs.

Unbundling Services:

Like tiered rates, energy consumers should be given a range of products and services that are cost-based and free from subsidies financed by other products or services. Over time, energy providers will be able to profit from those services they can efficiently provide, while energy users are assured those products and services are provided at the lowest possible cost.

Cross-subsidization is not what market solutions are about. Energy efficiency programs and energy products and services all need to stand on their own economic feet.

VI. CONCLUDING REMARKS

Mr. Chairman, there is a lot of work that will be done on these topics over the coming months. PGE intends to remain involved and constructive.

To summarize my remarks, I believe that:

- PGE and the region need a healthy Bonneville Power Administration.

- Competition is alive and well in the Northwest, but savings are being offset by the increased cost of doing business, created by both environmental and regulatory demands.

- It is PGE's experience that change is inevitable, and that BPA needs to change, and change quickly.

- We believe change can be effected decisively and within a year, if management has the right tools.

- In order to change quickly, Congress needs to consider changing BPA's personnel requirments, perhaps through implementation of a Bonneville Corporation.

Finally, I want to say, we believe Administrator Hardy and his management team are on the right track. They have demonstrated in the early stages the commitment and action that is necessary. We support them.

Again, thank you for this opportunity to share my thoughts with the Task Force. I'd be glad to answer any questions you might have.

STATEMENT OF MARK CRISSON

Mr. CRISSON. Good morning, Chairman DeFazio and Congressman LaRocco. My name is Mark Crisson and I am the director of Tacoma Public Utilities, Tacoma, Washington.

I appreciate the opportunity to testify today on behalf of the Public Generating Pool which is an association of eight public utilities in Oregon and Washington, three municipal utilities—Tacoma City Light, Seattle City Light, Eugene Water and Electric Board—and five PUDs in the State of Washington. We serve our customers with a combination of purchases from Bonneville and from our own generating facilities. In 1992 the PGP utilities accounted for about 15 percent of Bonneville's sales in the Northwest. We are also extensive users of the Bonneville transmission system. And the PGP utilities are also very active in Bonneville's conservation program and implementation.

I want to focus primarily on the issue of competitiveness and make a few comments on that and then talk a little bit about some of the concerns we have about what we see as a transition from Bonneville today to a more competitive Bonneville in the future.

As we have heard this morning, Bonneville has come under increasing pressure to become more competitive. As you have heard from other witnesses, its customers face these same pressures. We support the efforts of this task force and Bonneville and its customers to find ways to make Bonneville more efficient and more effective. Many of Bonneville's public utility customers have undergone similar kinds of efforts that the Administrator discussed earlier today or are in the process of doing so. I would like to comment that I believe the Administrator is to be commended for initiating a number of the things he described this morning. I know the Leadership EDGE, for example, which is undertaking to fundamentally change the organizational culture, puts a tremendous demand on top manager's time. It is a process that is going to require some time to make any progress. I am very encouraged to see that start. The function-by-function review, which involved a number of Bonneville's customers, is also off to a good start. I think under the circumstances the Bonneville management team is doing an excellent job and we support the effort.

Much of the attention to date is emphasized in the need to cut unnecessary costs and programs. We concur that those are important objectives. Consequently, we do support looking at this option of the government corporation in order to streamline some of the federal procurement and work force management rules that Bonneville now has to follow.

Another important aspect of Bonneville competitiveness is the whole issue of the need for Bonneville to refocus itself on a well-defined set of core services. We propose that BPA rededicate itself to providing basically three types of service to the region by unbundling its current service and that those services be offered at cost, as has been strongly urged by a number of other witnesses today.

The first service would be that which Congress originally created Bonneville to provide; namely, the marketing of power produced by the federal Columbia and Snake River systems along with other resources in the federal base system. PGP believes that Bonneville

should continue to market FBS power at cost in a way that would maximize the benefits and to set the rates at the actual cost of those services. And to address a comment or question that was raised earlier by the Chairman. We see the FBS cost as including necessary cost for fish and wildlife mitigation.

The second service the region clearly needs Bonneville to provide is transmission of both FBS and non-federal power. Again, we support setting Bonneville's transmission rates at the actual cost of owning and operating the facilities, and we support further opportunities for Bonneville customers to participate in regionally needed investments and new transmission facilities such as the Third AC project.

The third primary service is a little bit different, but it is no less important. That has to do with the issue of Bonneville working with its customers to acquire regionally needed new resources. It is important to recognize that this category of service involves responsibilities that Bonneville actually shares with its customers. Specifically, under the Regional Act, Bonneville is encouraged to work with its customers to develop new resources either on their own or with assistance from Bonneville. Accordingly, we believe that Bonneville should continue to support its customers in acquiring new resources.

Under the partnership approach, we envision Bonneville would participate in acquiring the new resources but only to the extent that customers formally request service from Bonneville. Further, as a general rule, when Bonneville provides new resource services, customers who buy those services should reimburse Bonneville for the actual cost of those new resources.

That last item raises a concern that I would like to address under the heading of transition to a new Bonneville. We support taking steps toward a new Bonneville organized around these three basic types of service with the rates set at the actual cost of providing each service. However, we are also interested in ensuring that, if significant changes are made, there be as smooth a transition as possible to the new BPA. One particular concern that we have is that during the transition Bonneville customers continue to have the ability to acquire regionally cost-effective conservation and renewable resources.

PGP utilities along with other Bonneville customers have made significant commitments to acquiring these resources—staff commitments, financial commitments, contractual commitments—with the assurance that regionalized funding would be available to support those efforts. For example, my utility is currently involved in a very large conservation project—I think it is the largest single one in the region—to develop 5 average megawatts of conservation from our Ft. Lewis facility. Our ability to maintain that effort and to do this and other projects during the transition to a restructured Bonneville so that opportunities are not lost and so that regional conservation targets are met should be a priority of this effort.

Now one of the problems here potentially with this objective is that, to the extent some continued regional funding of conservation and renewable resources is needed during the transition to a new Bonneville, it may be necessary to support the use of revenues from the sale of the FBS power or the first tier if a tiered rate is estab-

lished as a funding source. We are working with Bonneville's customers to investigate ways to do this.

To address the point made earlier about a requirement for some ongoing need for a residual funding level from the first tier to continue to support conservation and renewables, I am not willing at this point to say that is necessary indefinitely. What I am concerned about is establishing a transition plan, hopefully for a finite period of time, to get us to a point where the unbundling and tiered rates would provide a competitive market in which we can continue to meet renewable and conservation targets.

As I noted earlier, I think there is broad support among Bonneville customers for moving toward a more efficient and effective Bonneville. We are currently working with other Bonneville customers and are prepared to work with BPA and other groups on the details of how this approach could be implemented, including transition issues of the type I just described. It is essential that Bonneville change and improve, and we are optimistic that it can. We also welcome the task force's attention to these matters and stand ready to work with you as needed.

Thank you.

Mr. DEFAZIO. Thank you. I appreciate it.

Mr. Pilon.

[Prepared statement of Mr. Crisson follows:]

Public Generating Pool
Testimony before the
U.S. House of Representatives
Committee on Natural Resources BPA Task Force

Eugene, Oregon
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Presented by:

Mark Crisson
Director of Utilities
Tacoma Public Utilities
Tacoma, Washington

Background on PGP

The Public Generating Pool (PGP) is an association of three municipal utilities (Eugene Water & Electric Board, Seattle City Light, and Tacoma Public Utilities) and five public utility districts (Chelan County PUD, Cowlitz County PUD, Douglas County PUD, Grant County PUD, and Pend Oreille County PUD). Seven PGP members are located in Washington State and the eighth is located here in Eugene. PGP utilities serve approximately one out of every six Pacific Northwest residents and as a group own and operate one-fifth of the Region's hydroelectric generating capacity. As consumer-owned utilities with public preference rights, PGP members purchase about 15 percent of BPA's total Northwest power sales. In addition, we are major purchasers of BPA network and Intertie transmission services which we use to deliver power from our own nonfederal generating facilities. Further, PGP members are recognized leaders in the acquisition of regionally cost-effective conservation resources. Several PGP members are also working to meet more of their customers' needs by acquiring new generating resources rather than placing additional load on BPA. So, as you can see, the PGP utilities are involved in virtually every aspect of what BPA does.

Answers to Specific Questions Depend on BPA Services

Given the breadth of its members' relationships with BPA, the PGP is uniquely positioned to respond to the Task Force's questions about BPA competitiveness. You'll find that our answers reflect the PGP utilities' long experience both as purchasers of federal power and as developers of nonfederal resources and we also note that many of the Task Force's specific questions point

toward a broader, more fundamental policy issue. Stated in general terms, this question is: *What basic services will the Region need BPA to provide in the future, and how shall BPA provide those services?* Depending on what response is given to this broad question, the PGP's answers to the Task Force's specific questions could be very different.

For example, one approach would be to assign a greatly expanded scope and variety of responsibilities to BPA, including the ability to bundle or unbundle and price a variety of services based on what the market will bear, rather than what BPA's customers want or what the actual costs are for BPA to provide each service. The PGP members would vigorously object to setting up a greatly expanded BPA and allowing it to move away from cost-based rates, however beneficent the intentions might be. But if that approach is pursued anyway, we would want very clear limits imposed on BPA to prevent it from abusing its market power or blocking what would very likely become a mass exodus of the Region's utilities away from the BPA system. These limits on BPA would have to include greater third-party oversight to protect BPA's customers, and power sale contracts that would allow customers to terminate their power purchases from BPA and receive nondiscriminatory transmission service in exchange.

The PGP believes that a more workable response to the basic policy question would be to refocus BPA on the key services that it is uniquely able to provide to the Region. Customers would have the ability to choose the services they want from BPA and would pay BPA's actual costs to provide those services, including the associated costs for environmental restoration. The PGP would find this approach to be much more practical, equitable, and efficient and we would therefore feel less of a need for additional third-party protection from BPA or for the ability to distance our relationship with BPA.

A Word About 'Competitiveness'

Before I get into the issue of focusing BPA on a few basic services, I'd like to briefly respond to the Task Force's question about BPA 'competitiveness'. Competitiveness has become a buzzword in recent discussions about BPA, but I suspect that it has very different meanings to different people. From my point of view, you have to do two things to become competitive. First, you need to identify the services that your customers want and need—and that you are best-qualified to provide. Once you know what services to provide, competitiveness means moving forward to provide each service as efficiently and cost-effectively as possible. And if it is later found that your customers don't need your service or prefer to get it elsewhere, you either cut your costs, improve your product or drop out of the market for that service.

On the flip side, competitiveness does not mean forcibly trying to provide services that your customers don't need or that other providers are better able to deliver. It also does not mean charging different customers different prices for the same service, or forcing customers to buy

a service that they don't want in order to buy another service that they do want, or using one service to subsidize another service that your customers don't want. It does not mean blocking access by your customers to competing providers or preventing your customers from satisfying their own needs. These things are in fact anti-competitive and the PGP wants to emphasize that we are not at all interested in seeing BPA start to operate in an anti-competitive fashion.

Instead, the PGP believes that the first step toward making BPA more competitive is deciding what services BPA will—and won't—provide in view of its customers' needs, its capabilities, and the available alternatives. Then BPA should focus on providing each service to its customers as efficiently as possible. My remaining remarks will focus primarily on this first step, identifying the services that BPA should provide.

BPA Provides Three Basic Services

The PGP believes that BPA's fundamental services can be grouped into three general categories. First, BPA markets power from the existing Federal Base System resources, mainly the Corps and Bureau hydroelectric facilities on the Columbia River system. Second, BPA provides bulk transmission of both federal and nonfederal power within the Pacific Northwest and between the Northwest and other regions. Third, BPA is responsible for working—in partnership—with its regional customers to acquire regionally cost-effective new resources needed to serve the Region's needs.

Of course, within each of these three broad categories BPA has, over time, accumulated various specific responsibilities. For example, BPA funding for fish and wildlife restoration activities is mainly associated with its marketing of power generated at federal hydro facilities. Similarly, BPA funding for research on EMF is part of its responsibility as a regional transmission service provider. But the important point to consider here is that each of BPA's specific programs can, or at least should be, legitimately attributable to one of its three primary services—marketing FBS power, transmitting federal and nonfederal power, and working with regional customers to acquire new resources.

So, that is a simple answer to the question regarding BPA's basic services. By looking at each of BPA's three main services in a bit more detail additional Task Force questions can be addressed.

One: Marketing FBS Power

First, the PGP believes that BPA needs to refocus on its core service of marketing power from existing FBS resources. The federal Columbia River hydroelectric facilities are a tremendous resource for the Pacific Northwest providing not only power but also flood control, navigation,

irrigation, and recreational benefits. BPA was originally created to market power from these federal resources and it clearly continues to have an obligation to manage and preserve them so that their long-term value to the Region can be maximized.

The PGP believes that treating BPA's FBS power marketing function as a distinct service will allow it to be run more efficiently and with greater accountability. For example, BPA funding of fish and wildlife restoration activities associated with the FBS resources should be treated as an essential activity within the FBS power marketing function. Costs for these and other FBS-related activities should be recovered through the rates that BPA charges for FBS power. Further, rates for FBS power should be set at BPA's actual cost of service, not at some hypothetical marginal cost. We suggest that FBS power rates should eventually be used to fund only those programs and activities directly associated with the production of FBS power, rather than to subsidize other types of services or unrelated programs.

In other words, the PGP would support the unbundling of BPA's FBS power marketing service from its other services, including new resource acquisition. We would also support some limited unbundling within the FBS services, but only to the extent that BPA's customers ask to buy them separately, and only if the unbundled services can be sold at a verifiable cost of service. PGP members would take vigorous exception to unbundling of essential FBS services if they were to be priced above actual cost of service. We would be particularly opposed to BPA moving toward what it has recently termed 'value-based' pricing, where rates would be based on customer ability to pay, rather than cost.

The PGP also supports BPA's use of seasonal power exchanges and other techniques to reshape FBS generation. However, these transactions should be used only for fish restoration and to configure output from the FBS to the match the needs of BPA's preference customers. Any excess of nonfirm FBS power should be made available to BPA's Northwest customers, for example to regional utilities who wish to use new resources to firm up nonfirm FBS hydroelectric power. And BPA should not use sales or exchanges of FBS power outside the Pacific Northwest as a way to justify or subsidize BPA acquisition of new resources.

<u>Two: Transmission of Federal and Nonfederal Power</u>

BPA's second primary area of responsibility is to provide bulk transmission service for both federal and nonfederal power. Here too, the PGP recommends that BPA focus on transmission as a primary service, with its overall goal being the satisfaction of all customer requests for service, subject to existing federal statutory and regulatory limitations specific to the Pacific Northwest.

Of course, BPA must maintain the ability to use its transmission system to deliver power from

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the existing FBS resources. However, the PGP believes that by treating transmission more distinctly as a service, BPA can also improve its ability to satisfy, in a nondiscriminatory way, both existing and new nonfederal transmission demands. Again, the PGP recommends that the best way to accomplish this is to set BPA's transmission rates at the actual cost of service for existing facilities, except in clearly defined circumstances such as when new facilities are needed to serve an out-of-region customer. When expansions to the Regional transmission system are needed, we support increased customer participation and ownership, both to improve efficient use of the Region's resources and as a way to lessen BPA's need to borrow from the federal government.

The PGP's basic concern is that BPA not use its transmission system to limit the availability of new nonfederal resources or to artificially influence resource decisions by its customers. Instead, it should offer transmission as a nondiscriminatory, cost-based service.

Three: Partnership in New Resource Development

The third primary service that BPA provides is its participation in acquisition of regionally cost-effective new resources. This service is somewhat unique in that, under the Pacific Northwest Electric Power Planning and Conservation Act, BPA actually has a ***shared*** responsibility to acquire new resources in partnership with its customers. However, we have recently seen that the partnership between BPA and its customers is not working as effectively as we hoped it would when the Act was developed. A variety of reasons can be given to explain this, including concerns about the efficiency of BPA's resource programs and the reluctance of some customers to share in the cost of new resources needed to serve other customers' load growth. With these concerns in mind, I would like to focus on the question of what BPA's customers need BPA to do in acquiring new resources.

Essentially, the PGP sees BPA as a potential provider of two types of new resource services, both of which appear to be decreasing in importance. First, BPA can serve as a regional 'flywheel' to absorb and spread the risks associated with the development of new resources. Historically, these risks were greatest for large, central-station generating projects. However, the role of central-station generation has been greatly diminished by the availability of smaller resources with significantly lower development risks. And much of these remaining development risks are being taken on by a vigorous new nonutility generation industry and joint utility efforts such as CARES. Thus, it is less clear today to what extent BPA is positioned to provide an extensive resource development risk pooling service for its customers—particularly for new generating resources.

The second type of new resource acquisition service that BPA may be able to provide is as a funding vehicle to compensate utilities who choose to develop regionally cost-effective new

resources. It is important to recognize that, to date, this funding mechanism has been made possible by the use of a melded wholesale power rate that blends the cost of new resources in with lower-cost FBS resources. Recently, there has been increasing pressure to move BPA toward a tiered rate design. Again, there are various motivations for this including an interest in sending an incremental price signal for new resources to promote more efficient resource choices by BPA's customers. But, to the extent that tiered rates eliminate the melding of costs for new and existing resources, they will fundamentally affect BPA's ability to serve as a funding vehicle to regionalize the cost of new resources.

Additional, very difficult issues must be solved before tiered rates could be implemented. For example, the PGP supports creating a first tier made up of FBS resources and basing the rate for first tier power on the cost of FBS resources. However, allocating this first tier among BPA's customers will require solving some significant technical and political issues.

BPA Wholesale Power Rates Should Be Cost-Based and Should Allow Cost-Effective Resource Acquisition

One way to continue regionalized funding for new resources without a melded BPA wholesale power rate might be to unbundle and price some BPA services above cost and use the proceeds to subsidize new resources. However, the PGP strongly recommends against such an approach, except as a solution to one transitional problem that I will describe in a moment. We are concerned that if BPA were to begin setting its rates to create extensive cross-subsidization between services, it would lead to reduced accountability, less efficient BPA programs, more acrimonious BPA rate cases, and restricted ability of BPA customers to make cost-effective resource choices. Further, if BPA were to gain the ability to shift its costs among different services, the resulting lack of rate stability would frustrate the Act's intention that BPA be available as a reliable partner to work with its customers in the development of new resources.

Thus, if a decision is made to move away from melded BPA wholesale power rates, the PGP recommends that rates for specific BPA services be set to the greatest extent possible at BPA's actual cost to provide those services. For example, rates for FBS power sold to public preference customers should be set at the actual cost of the FBS resources and rates for power from any new generating resources that BPA acquires should be set at the actual cost of those new generating resources.

In addition, any restructuring of BPA's rates must provide for a smooth transition to a more efficient and competitive market for new resources. Again, we believe that this can best be accomplished by setting rates for each of BPA's major services—marketing FBS power, providing transmission for federal and nonfederal power, and new resource acquisition—at the actual cost of those services. As noted above, this will give BPA's customers the most efficient price signal

and basis for making cost-effective resource decisions.

PGP Recommends Use of Revenue from FBS Power Sales for Transitional Funding of Conservation

Over the long-term, the PGP believes that setting BPA's rates for its services at the actual cost for each service will help its customers make cost-effective resource decisions while also keeping BPA focused on the services it is best able to provide. However, we recommend making one exception to this general approach. Specifically, the PGP recommends that for some transition period, funding for BPA customer acquisition of conservation should continue to be supported by revenues from the sale of FBS power.

This recommendation is based on the recognition that conservation is the Region's top-priority resource and that we must not allow the shift to a new BPA rate structure to disrupt the Region's acquisition of all cost-effective conservation. BPA's customers have made extensive commitments to this goal with the understanding that regional funding would be available to support their efforts. Thus, the PGP would not want a sudden end to regionalized funding for conservation to interfere with continued customer acquisition of regionally cost-effective conservation.

Instead, by continuing to provide regionalized funding for conservation until a new cost-based BPA rate structure is implemented and working effectively, BPA customers will be able to make a smoother transition to other funding mechanisms for conservation. Further, we think it makes sense to use revenues from FBS power sales to provide this transitional funding for conservation, in part because the resulting energy savings will serve to 'stretch' the capability of the FBS resources.

PGP Recommends a More Limited BPA Role in New Generating Resources

In contrast to conservation, the PGP believes that there is not a great need for transitional regionalized funding of new generating resources. As noted earlier, a vigorous nonutility generating sector already exists and is prepared to meet the Region's need for new generating resources. Because this market is available as an alternative to BPA acquisition of new generating resources, customers already face the price signals needed to make cost-effective resource decisions. Thus, with a cost-based BPA rate structure, we do not see a significant need for BPA to provide funding support for new generating resources either to its customers or to itself in the form of cross-subsidies between FBS resources and new resources.

Further, PGP recommends that BPA acquire new generating resources only to the extent that specific customers formally request it to do so, and only to the extent that those customers enter

into bilateral contracts with BPA for service at cost-based rates. For example, a customer could enter into a separate contract with BPA to buy power from a new resource or from a pool of new resources that BPA would then acquire on its behalf. The rate for power sold under such contracts should reflect BPA's actual costs for the new resource or pool of new resources involved. This will ensure that no cross-subsidization occurs between BPA sales of FBS power and BPA sales of power from new resources. In turn, it will allow BPA's customers to compare the true cost of new BPA-acquired resources with the cost of other resources that the customers could acquire directly, thereby promoting least-cost resource decisions by both BPA and its customers. Finally, this approach reinforces the BPA-customer partnership approach to acquiring new resources, rather than giving BPA excessive control over new resource acquisition.

PGP Recommendations are Consistent with Open Access Transmission and Increased Competition in Bulk Power Markets

At this point, I would like to look at the PGP's recommendations in the broader context of changes that are taking place in the electric utility industry as a whole. As you know, the National Energy Policy Act of 1992 contains a number of provisions designed to increase competition and efficiency in bulk power supply markets. The PGP supports this nationwide restructuring effort, including the move toward open access transmission and the entry of new suppliers in bulk power markets. However, we have equal interest in maintaining and maximizing the benefits already provided by the Pacific Northwest's existing base of federally-owned hydroelectric resources. Further, we believe that it is extremely important to keep both of these objectives in mind when considering the fundamental question about the responsibilities of BPA and of other industry participants.

The PGP supports the unbundling of power supply and transmission services in the Pacific Northwest. We believe that it is not only possible, but essential, that BPA continue to market FBS power on a cost-of-service basis, while it allows an open, competitive market for new resources to develop in the Region. To the greatest extent possible, this should involve a 'hands-off' approach by BPA towards its customers' resource decisions. BPA will be needed to provide both intra-regional and inter-regional transmission service, and BPA should be allowed to provide other services at the request of customers willing to pay the actual cost of those services. In short, we see the unbundling of BPA's services into FBS power marketing, transmission of federal and nonfederal power, and supporting customer acquisition of new resources as being fully consistent with the federal government's restructuring program for the U.S. electric industry.

PGP Recommendations will Make BPA More Efficient and Clarify BPA-Customer Relationships

The PGP's recommendations also provide a simple, straightforward basis for making BPA more efficient as well as more responsive to the needs of its customers and the Region as a whole.

By focusing BPA along three comparatively distinct lines of service, it will be easier to identify specific services that BPA should provide, programs that it should fund, and services or programs that can be revamped or assigned to other industry participants. Similarly, tying essential activities such as funding for fish and wildlife restoration in as part of broader services such as FBS power marketing will improve the accountability, efficiency, and results in each area. This basic approach also establishes a structured means for determining the extent to which specific BPA services should be bundled or unbundled to best meet customer needs. In turn, it will make it possible for each customer to enter into contracts with BPA for each of the three basic services it wants to purchase and on terms and conditions that reflect an appropriate level of commitment by each party to the agreements. Finally, the PGP recommendations establish clear guidelines for designing and setting BPA's rates.

PGP Comments on Repayment Proposals and BPA as a Government Corporation

The Clinton Administration's Report of the National Performance Review the 'Reinventing Government' initiative, has recommended that the Department of Energy work with BPA to restructure the financing of BPA's federal debt. It would allow BPA to issue bonds at market rates and use the proceeds to pay off its debt to the federal government. This recommendation is based on the premise that low interest rates on the existing loans to Power Marketing Agencies such as BPA have created undesirable federal subsidies and PMA rates that are "too low". The Clinton Administration's proposal, along with BPA's proposal to change its organizational structure to a government corporation raises, a number of questions and concerns for the PGP.

The PGP is opposed, as it has been in the past, to any effort to accelerate repayment of BPA's federal debt that would directly or indirectly raise the rates that BPA charges to recover its costs. If BPA were to go to the private market to issue bonds to repay its federal debt, the PGP would want to look closely at how the actual value placed on the federal debt would be calculated. Specifically, the face value of the debt should be adjusted to its net present value based on existing interest rates and the established repayment periods. In addition, the debt must include all of BPA's existing appropriated debt. Finally, we would want clear limits placed on the types of new debt that BPA would incur--for example to prevent it from borrowing money without adequate review and approval by its customers and Congress.

PGP would also want to closely review the upcoming DOE proposal regarding restructuring of BPA as a government corporation. Again, we are concerned that sufficient oversight of BPA continue to exist. Under the existing structure, BPA's customers maintain a level of influence over BPA through the annual Congressional appropriations process. As yet, it is unclear to the PGP how Congress, and in turn BPA's customers, would be able to adequately provide guidance for BPA's budgetary decisions. An additional advantage of the existing arrangement is that Congress provides a forum for all parties with an interest in BPA to express their views and

resolve any conflicts. The PGP is concerned that allowing greater autonomy for BPA could limit these opportunities for joint problem-solving.

As we have stated throughout this testimony, the PGP encourages BPA to refocus on its core services and to perform them more efficiently. We are willing to consider and participate constructively in restructuring proposals for BPA's services, its rates, and its organization. However, such restructuring and any proposal to refinance BPA's federal debt must not cause a diminishing of the economic benefits produced by the assets in which the citizens of the Pacific Northwest have invested.

STATEMENT OF FERGUS A. PILON

Mr. PILON. Good morning, Chairman DeFazio, Congressman LaRocco. I am happy to be here today and appreciate this opportunity to make some comments. Congressman LaRocco, I am particularly pleased to see you because I grew up in Pocatello. I spent 15 years of my life there and many of my friends who I still communicate with there speak highly of you. So I am very pleased to meet you today.

Mr. LAROCCO. It is always nice to hear that people outside my district are speaking highly of me. [Laughter.]

Mr. PILON. My name is Fergus Pilon, and I am the general manager at Columbia River PUD in St. Helens, Oregon. I am here today speaking on behalf of the Non-Generating Public Utility Group. Non-generators are Bonneville's special customers. We are the full-requirements customers. We depend solely on Bonneville for our power. The non-generators, while our organization consists of 25 utilities, there is many more of us in the region. It is a special relationship that has existed between Bonneville and its full-requirements customers for the past 50 years. That has to be maintained through any changes that we are envisioning for Bonneville for the next 50 years. We are here because of Bonneville, and Bonneville is here because of us if you will look back in history.

My comments today will be highlights from my written testimony. Why is it important for Bonneville to become more competitive? As we speak today, Bonneville is perceived as not being the least-cost, stable energy provider in the region. I recently met with some folks seeking to site an industrial facility in our service area and I offered them our retail rate and they were fully aware that I was a full-requirements customer of Bonneville. They were not interested in my retail rate. They were not interested in the discount on my retail rate. They were interested in generating their own electricity with natural gas because they think that will provide them a more competitive power in the long run. Now, in this particular case, gas happens to be a feedstock for their process, so they need to get gas there anyway. So it is a true cogeneration facility. It is not an IPP facility. They were interested in talking to me because they wanted me to buy power from them. So there is a serious issue of competitiveness in Bonneville's present rates.

Should Bonneville adopt tiered rates? I have been working at Public Power Council for the last two years in what we call the tiered-rate policy subgroup. It is a group of PPC Executive Committee members and we have come together and butted heads at times and laid our views out on the table, and the non-generating facilities are in support of Public Power Council's principles for tiered rates. Bill Drummond earlier referred to some of those principles and I will not get into them. I would like to point out that they are a dynamic set of principles. They are a little bit longer than the Director of the Washington Department of Energy spoke to this morning, but they are principles that we feel are very important for the implementation of tiered rates.

Bonneville is considering unbundling its services. This is a big concern for full-requirements customers of Bonneville. We buy a bundle of services right now—I suppose you could say from Bonneville—when we buy our power, and the cost for those services are

included in that priority firm rate, that rate we pay for our wholesale power. The major service I think we get is load following. Loads at night are much lower than they are in the day time during peak hours, and as a full-requirements customer, you do not have to worry about that. Bonneville takes care of it for you. There would be serious economic disadvantages that would flow to full-requirements customers if somehow we had to start paying for that. For 50 years it has been in our rate. I think it needs to continue to be in our rate. There needs to be a set of services that have historically been provided for full-requirements customers that remains imbedded in the priority firm rate for full-requirements customers.

Chairman DeFazio, I believe those comments address your question to the first panel on how unbundling would effect smaller utilities. Most of our utilities are a smaller size.

How should environmental externalities be distributed in tiered rates and/or unbundled services? Our view is that the rates for these unbundled services, be they bundled or unbundled, and rates for tiered rates or average system cost rates as they are now, those rates need to be determined based on a cost of service. Our main fear under an unbundled scenario is that Bonneville will price these unbundled services at a level that the market will bear. And Bonneville is not an investor-owned utility. Bonneville is a public agency, and they have some public policy concerns that they have to address. I think the major policy concern in unbundled services and in tiered rates are rates based on cost.

A cost of service study—I am using that term generically—on these unbundled services and tiered rates needs to capture those costs in the agency and apply them to the resource that generates those costs. Fish and wildlife needs to be applied to the hydrosystem. Transmission costs need to be provided—or applied to transmission system rates. That is what I am referring to.

Should the variable rate for the direct service industries be eliminated? I believe current economic circumstances in the Northwest, including load resource balance, the variable rate for the DSI is no longer appropriate. Up until, I think, the second quarter of Bonneville's fiscal year 1993, there were still some positive benefits to all those non-aluminum smelter customers of Bonneville in that the estimate was that a variable rate brought in more revenues than otherwise would have happened. In the last 2 years, that has been declining rapidly, and I would suspect by the end of Bonneville's fiscal year, that we will be worse off because of the variable rate.

On the value of reserves for the direct service industries, we believe there is no value for reserve on the second quartile. The value for reserve on the first quartile, the calculation on that—I am not familiar enough with it on how the calculation is done, but I am aware that it has not been updated in some time. We believe the value of the reserves should be no more than $20 million a year.

Since my orange light is on, I am going to skip comments on irrigation discount. We do support the irrigation discount. Don Clayhold will give you a very full analysis of the irrigation discount I am sure in his testimony.

Our group also supports the low-density discount. The low-density discount is in the Act. It is part of a law. And it is there be-

cause it is an attempt to equally position Bonneville's customers who are otherwise disadvantaged either because of sparse populations or because they have a high debt-to-sales ratio. It is an equity issue, and it keeps the rural customers more competitive.

Thank you for this time and good luck in your deliberations.

Mr. DEFAZIO. Thank you.

Mr. Golden.

[Prepared statement of Mr. Pilon follows:]

TESTIMONY BEFORE THE U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON NATURAL RESOURCES

by

Fergus A. Pilon, General Manager
Columbia River People's Utility District

for

Non-Generating Public Utilities

Members of the Committee:

I am Fergus Pilon, Manager of Columbia River People's Utility District headquartered in St. Helens, Oregon. Today I represent the 25 publicly and cooperatively owned utility members of the Non-Generating Public Utilities Group. These utilities represent a cross section of BPA's requirements customers (customers that rely on Bonneville for meeting existing and future load growth). As a group, our members and other similar Bonneville customers have the most at stake in the reshaping of Bonneville into a more competitive entity. If BPA rates are not competitive, then the customers we serve and the economic fortunes of our service area will be at a competitive disadvantage with their neighbors. Most of our members do not have any imbedded low cost resources of their own to offset higher BPA rates. Further, requirements customers generally serve the areas outside of the "I-5 Corridor," the areas suffering the economic decline of the timber and agriculture industries. The economic welfare of these service areas depend on reshaping Bonneville into a customer oriented cost-effective agency. We are pleased to provide the following responses to the questions that the Committee has asked us to address.

1. **Why is it important for BPA to become more "competitive"? How likely is it that BPA will become a higher cost supplier of energy to the region than other providers? Are there other reasons for BPA to**

undertake its competitiveness initiative? What principles should guide BPA in this effort?

As we speak today, Bonneville is no longer perceived as the lowest cost provider of electric energy in the Northwest. For example, one industry planning to locate in the service area of one of our members has elected to develop its own generation to serve their new load rather than face the uncertainty surrounding BPA's future rates. The industry believes that it can produce electricity for its own needs at a lower cost than buying power at retail from the local utility. Even worse, potential commercial and industrial customers that lack the economic ability to provide their own generation may avoid requirements customer's service areas and thereby stifle economic growth that should occur in those areas.

BPA's wholesale rates already exceed the generation and transmission costs of at least one investor owned utility in the region and are roughly equivalent to several others. If the trend continues of loading an unfair share of non-power costs on BPA customers, and Bonneville cannot achieve the efficiency improvements hoped for in their current efforts, it is almost certain that BPA will not be a competitive power supplier in the future. Bonneville cannot continue to be the "deep pocket" for every interest group that believes it deserves to be funded by BPA revenues paid by BPA customers. There must be accountability for the dollars spent. We strongly support BPA's current efforts to become more competitive.

Another reason for Bonneville to become and remain competitive relates to fish and wildlife costs. The Regional Act clearly mandates that BPA and the Power Planning Council "protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of such facilities . . . <u>while assuring the Pacific Northwest an adequate, efficient, economical and reliable power supply</u>". (emphasis added) In today's competitive environment, these provisions are even more relevant. Bonneville is reaching the point that it will be unable to fund fish and wildlife activities and remain competitive. Currently, revenues from Bonneville customers are funding about $300,000,000 of the region's fish and wildlife activities and these costs have a direct effect on Bonneville's competitiveness.

2. **Should Bonneville adopt tiered rates? If not, why not? If so, how should there rates be structured? If there is a specific model or framework for Bonneville tiered rates that you support, please describe**

it in detail. What principles should be used in the development of these rates? Can tiered rates be designed so that they do not discourage development of new industry in areas served by customers of Bonneville? Should the Federal Base System be allocated through a tiered rate system?

These questions about tiered rates are certainly appropriate. BPA requirements customers all have similar questions. The Public Power Council is well underway addressing the issues surrounding tiered rates, and we support the PPC as the forum for developing a regional consensus of Bonneville preference customers on this issue. If there continues to be no consensus on tiered rates, Bonneville's ability to sign new contracts implementing tiered rates with its customers will be impossible.

Our members are apprehensive about the impact that a tiered rate structure may have on economic growth in their service areas as compared to neighboring utilities. We also recognize that we may benefit if our members can, in fact, develop new conservation and generating resources at less cost than BPA.

A potential positive effect of tiered rates is that BPA customers could directly compete with BPA for new conservation and generating resources. If BPA tier 2 costs are lower than costs for other resources available to a customer, then the customer will elect to purchase from BPA.

BPA requirements customers do face some difficult problems if tiered rates are adopted by BPA. As opposed to the larger utilities with a large existing load base and their own low cost imbedded generating resources, smaller utilities will find it hard to provide attractive rates for new commercial or industrial loads which would otherwise locate in their service area. In addition, smaller utilities by themselves may not be able to participate in new generation opportunities that allow them to remain competitive. They may face few choices other than accepting a non-competitive tier 2 rate.

The issues surrounding the allocation of tier 1 power to individual utilities are particularly difficult for requirements customers. Will the allocation be fixed without regard to changes in the operation of underlying resources? Will new preference customers be entitled to an allocation that reduces existing customers' allocations? If there are surpluses of power on the Bonneville system, will tier 1 power availability be increased? pro rata? Frankly, there are no easy answers to these issues and that may indeed

cause the idea of tiered rates to fail, no matter how much merit there is in the idea.

3. **Bonneville is considering unbundling the services it provides such as transmission, storage, load-shaping and integration services. What are the potential benefits and drawbacks of unbundling? If Bonneville pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some Bonneville services that cannot be unbundled?**

   Are you aware of any examples in either the public or private sectors of unbundled wholesale power services?

Unbundling at present is an undefined term. The degree of unbundling and its effect on requirements customers' competitiveness is of great concern. Obviously, if unbundling provides Bonneville additional revenue without seriously impacting the overall costs for power used by Bonneville's "core" customers, we will support the concept. On the other hand, if unbundling leads Bonneville away from cost based rates and the "postage stamp" rate concept, we will be harmed and the region will suffer.

The small and medium sized requirements customers are Bonneville's core business. Their ability to compete is the ultimate test of the current efforts to make Bonneville competitive. Increasing the rate disparity between these utilities and their larger more integrated neighbors is not in Bonneville's or the region's interest.

One of the problems for all small and medium sized requirements customers is their isolated service areas. Bonneville, through its extensive transmission grid and interconnections with the region's larger integrated systems, is a key partner in making these customers a complete "integrated" utility competitive with the larger integrated systems in serving the needs of their customers. When a new customer of Pacific Power in Eastern Oregon asks for service, Pacific Power does not penalize that customer because it is remote from Pacific Power's generating resources. If Bonneville adopts unbundled transmission rates that increase transmission costs to remote service areas, the ability of small communities to have competitive rates will be even more difficult. Further, if an intervening utility's transmission system is involved, BPA is a necessary partner in assuring fair transmission costs across those systems. Unbundling must not dissolve the ability of

requirements customers to compete as "integrated systems" in partnership with Bonneville.

4. **How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must Bonneville do to ensure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection of fish and wildlife?**

   How can the region maintain the benefits of regional coordination and planning if resource acquisition and transmission become more decentralized as a result of tiered rates and unbundling?

Cost based rates, bundled or unbundled, tiered or not tiered, is the principle that must apply to BPA and preference agency ratemaking. External costs actually accrued should be applied to the source of the external payment. That is fish and wildlife costs attributable to a hydro resource should be recovered from the rate pool that the resource supports.

We doubt that unbundling will diminish Bonneville's commitment to meet its statutory obligation to protect fish and wildlife. While we support Bonneville meeting its statutory obligation regarding fish and wildlife protection, it is important to note that since the passage of the Regional Act Bonneville has been the "deep pocket" for cash starved fish and wildlife agencies who have not contributed their share. The Regional Act contemplated BPA only doing its share and only after those with direct and already existing responsibilities had provided their own funds as required under existing law. If competitiveness means better accountability in the spending of revenues provided by Bonneville customers, that is a net benefit to the region.

Both Bonneville and the Power Planning Council should continue to provide the "vision" of the benefits of coordinated planning to the region's utilities. The utility industry, however, is rapidly changing to a less regulated, more competitive model. As we all have experienced, centralized planning does not guarantee the most efficient result. Regional planners will have to be more realistic about the changes that are coming in the power industry and provide planning assistance that the utilities can use in the real world of competition.

5. **Should the variable rate for the Direct Service Industries (DSIs) be eliminated or modified? Please provide an estimate of the cost and/or benefit of to regional ratepayers of continuing to provide this variable rate.**

What is the current value of reserve (VOR) of the first quartile of the DSI allocation? What is the current VOR of the second quartile?

Under the current circumstances, there is no justification for continuing the Variable Rate for the DSIs. BPA is no longer surplus in firm power resources and is acquiring short-term and long-term resources to cover its power deficits. The Variable Rate, when it was adopted, provided revenue benefits to Bonneville and its other customers. That benefit to Bonneville revenues (an additional $23.5 million from 1986 through the first quarter of 1993) is no longer relevant. The changes in the world aluminum market have most economists pessimistic over the potential for higher aluminum prices. Therefore, we conclude that the prospect for any net benefit to BPA revenues from the Variable Rate is highly doubtful and its continuation is unwarranted.

The current value of reserves provided by the DSIs and reflected in DSI rates is valued by BPA to be about $60 million per year. With the changes in BPA's resource programs, the value of the second quartile versus its current cost ($30 million) is not justified across the board. We favor a hard look at what reserves are economic to the system and some major revisions in their application. Based on current expectations the value we estimate for reserves is more in the order of $20 million.

6. **Should the irrigation discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this discount.**

We favor continuation of the irrigation discount or a special rate reflecting the cost of service to these loads. Irrigation loads are unique in that the loads coincide with the periods when Bonneville has surplus capacity and energy available on the system. They place no planning burden on BPA during the winter peak and provide a "round the clock" load when the flow requirements for fish put the hydro system in a "spill" condition. Bonneville in its rate process can evaluate the cost of service to this important segment of the Northwest economy and set the rate appropriately.

7. Should the low-density discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide these discounts.

We favor continuation of the low density discount. As we have indicated earlier, Bonneville's role in the region has been to provide "integrated" service to the remote areas of the region. The low density discount is a recognition that some small systems need some additional support to assure that Bonneville's original charter is continued -- that is to assure the widest spread use of Federal power. Further, it is important to remember that the low density discount is specifically provided for in the Regional Power Planning Act (Section 7.(d)(1)). Again, the ultimate test is the competitiveness of all requirements customers, including those customers with difficult service areas, not just that of BPA wholesale costs. While Bonneville must become more business like in its approach, we can not favor eliminating the low density discount. Obviously, BPA must continue to evaluate the application and cost benefit to individual utilities to assure fairness to its other customers. This is in keeping with the provisions of the Bonneville Act and the Regional Act.

8. Are there any other subsidies or discounts that Bonneville provides to certain customers that should be eliminated?

We hope that Bonneville, in becoming more competitive, is able to continue to remember its basic role in the region. The requirements customers of Bonneville represent its core business. If BPA becomes a "profit maximizer" in the model of some mainstream business organization, the small outlying areas will suffer tremendous negative economic consequences. In the utility business, there are what some would term "subsidies". Are IOU ratepayers in Portland subsidizing ratepayers in Condon, Oregon? The point is that the universal availability of power in the region at fair rates should be a given. The ratepayers in Portland have a stake in the economic success of Condon in the same manner that the public power ratepayers in Seattle have a stake in the economic success of Republic, Washington.

9. Should the provisions in the power sales contract which allow some utilities to be reimbursed by Bonneville for lost revenue when a voluntary curtailment is implemented be retained?

Yes. Under the regional "Share the Shortage" Agreement, Bonneville's customers will be asked to curtail their sales so that other higher priority loads can be served. Because some of these customers are requirements customers, any saved power ends up on BPA's system to be sold at marginal rates. The curtailment of these loads reduces the net operating revenue of these utilities and they should be reimbursed for that net revenue loss.

10. How should the long-term power contracts that Bonneville is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

The negotiations regarding new power sales contracts is ongoing. The agreements represent the business relationship between Bonneville and its power customers. In the end, the terms and conditions of the agreements have to be satisfactory to two parties, BPA and the customer. We are working with the PPC to develop consistent provisions that will define the business relationship. But to speculate on what should be included or not included at this time is premature.

We recognize the interest of non-customers in the negotiations between BPA and its customers. However, their stake in the negotiations is much different than the customers. We are sure that Bonneville, in its development of the contracts, will take into account the environmental issues raised in the process. But, in the end, both Bonneville and the customers are entering into a mutually agreed business arrangement that must be acceptable to both parties.

11. It has been suggested that the residential exchange program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

The residential exchange represents an income transfer of $200 million to the customers of investor owned utilities in the region. In a time when BPA's wholesale costs are becoming non-competitive, this transfer has become a burden to BPA's preference customers that needs to be reduced or eliminated. One alternative available to BPA under the Regional Act is to substitute lower cost BPA acquisitions for the average cost of IOU resources

acquired by BPA in the residential exchange. With the current cost of generation at very attractive levels, it may be time for BPA to exercise that option.

12. What part should Bonneville's existing resource acquisition programs play in Bonneville's competitiveness initiative, both during a transition period and after Bonneville has adopted some of the changes it is considering?

The restructuring of BPA's resource acquisition activities will play an important part in the success of its competitiveness initiative. We believe that the change must begin immediately. BPA has a total of 505 FTE (388 BPA and 117 Contractor) working on a variety of resource acquisition activities or roughly five BPA resource employees for each preference customer in the region. Even if conservation programs are more labor intensive than other resource acquisition programs, it is hard to conceive we are getting cost-effective value out of these numbers. Considering that the utilities are the entities that are dealing with retail customers and are doing the job with many less employees, its time for serious changes in BPA's approach.

Much of the problem of BPA's current approach lies in the elaborate procedures, tracking and continual "tweaking" that has developed over the years. BPA's current system carries a 40% overhead loading. That means 40 cents of every conservation dollar actually goes to support this organization.

We would suggest the following steps be taken in the transition period to a more competitive BPA:

a. Immediately proceed to the mean and lean organization that will meet the competitive demands of the future (customer focused, core business/market driven, cost conscious, and results-oriented). Waiting will only increase the uncertainty and lessen the ability to make decisions.

b. Use the transition period as a period of experimentation. This period could allow for adopting pilot programs that encourage cost sharing between Bonneville, the utility customer and the power consumer of the benefits of conservation investments and 100% financing of conservation. Similar approaches have been

working well on other systems. Other pilot programs such as issuing RFPs for preference customer conservation proposals, direct allocation of conservation monies to the utility customers, could also hold promise.

c. Bonneville should avoid redesigning conservation programs during the transition, unless done in the above experimental mode. However, new conservation contracts with customers should allow for reasonable retroactive changes that enhance the equitable sharing of program costs.

d. Place more emphasis on the direct involvement of the boards, management and staff as local decision makers who can provide on the ground credibility for worthwhile conservation programs.

We believe the new Bonneville's resource activities will be more responsive to what its requirements customers ask it to do. The charter that the Regional Act gave Bonneville was to acquire resources to meet loads <u>that its customers asked that it meet</u>. In the future, with or without tiered rates, the means of meeting those loads will require the active agreement of those utilities.

13. Please provide any other suggestions regarding actions that would make Bonneville more competitive or cost-effective.

Bonneville needs Northwest congressional support in getting rid of the red tape that the DOE and OMB have inflicted on Bonneville. The current effort in using BPA as a laboratory to "reinvent government" should be used to allow BPA to make timely and more cost-effective decisions. Additionally, members of Congress should recognize that asking BPA act as a "deep pocket" to pay for non-power system expenses of regional agencies has become an unfair burden to Bonneville customers and is contributing to BPA's lack of competitiveness. Bonneville has served the region well in the past 50 years, it deserves the chance to regroup and continue to be a major regional asset.

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TESTIMONY BEFORE THE U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON NATURAL RESOURCES

by
Columbia River People's Utility District

September 25, 1993
Eugene, Oregon

1. Why is it important for Bonneville to become more "competitive"? How likely is it that Bonneville will become a higher cost supplier of energy to the region than other providers? Are there other reasons for Bonneville to undertake its competitiveness initiative? What principles should guide Bonneville in this effort?

As we speak today, Bonneville is no longer perceived as the lowest cost provider of electric energy in the Northwest. Recent negotiations with prospective industrial customers who want to locate new manufacturing facilities in the service territory of one of our members, revealed that they are planning their own generation because of the uncertainty surrounding Bonneville's electric rates. The plant will be a net producer of electricity because they can generate their own electricity for less than the present retail rate, now and in the future.

Bonneville must continue its competitiveness initiative and cost savings must come from that study. Even if the competitiveness initiative is successful it will provide only modest rate relief. The major "principle" that should guide us all is, Bonneville can not continue to be the deep pocket for everything in the region that various interest groups think needs funding even if remotely related to the hydroelectric system. There must be accountability for the dollars being spent.

2. Should Bonneville adopt tiered rates? If not, why not? If so, how should these rates be structured? If there is a specific model or framework for Bonneville tiered rates that you support, please describe it in detail. What principles should be used in the development of these rates? Can tiered rates be designed so that they do not discourage development of new industry in areas served by customers of Bonneville? Should federal base system resources be allocated through a tiered rate system?

First, we believe tiered wholesale rates will be the death knell for public preference as we know it in the Northwest. Tiered rates will create two classes of Bonneville customers, the haves and the have nots. The haves are those larger utilities who have the capability to develop and system size to support their own generation and the have nots are the smaller utilities who will

be dependent on Bonneville for both tier I and tier II. The have nots will have unattractive alternatives for any new commercial or industrial customers in their service territory.

Second, it is our view that our blended wholesale cost of power will increase more rapidly with tiered rates than with the historically sufficient average system cost based rates. Tiered rates will require an allocation of the Federal Base System (FBS) and if recent history is any indication, the FBS will continue to shrink, thus forcing even a non-growing utility to purchase more and more of its resource needs at the tier II price.

Third, and certainly not the least, tiered rates and the allocation of the FBS necessary for tiered rates will certainly make it more difficult for new public preference customers to be formed. Do we want to bring the option of public power to an end for the vast majority of Oregonians?

We do not deny that things need to change if Bonneville is to remain competitive and we propose the following alternatives to tiered rates. Conservation is the least cost resource and must be pursued, we simply must lower our per-capita consumption of electric energy. First, we propose a conservation surcharge on utilities that do not capture a certain percent penetration of their conservation "technical potential" over a set time period. Each individual utility would decide how that would be accomplished and without funding from Bonneville. Bonneville's role under this proposal would be research and development and auditing for surcharge determination. There would be no conservation implementation or incentive money in the Bonneville budget, not one dollar.

Second, Billing Credits needs to be operated as the main resource acquisition tool. Billing Credits would work if Bonneville really wanted it to work and really wanted partnerships with its customers. Billing Credits could become the major third party financing mechanism for Bonneville. Under a functioning Billing Credits resource acquisition program, regional resource planning remains intact. With tiered rates, regional resource planning will be in jeopardy and billing credits makes little sense.

If these two recommendations were implemented, conservation implementation surcharge and a functioning Billing Credits, Bonneville could remain under the present debt cap and would not need access to the private bond market. Also, the pressure on rates because of resource development (including conservation) would be relieved. There might even be the possibility for a rate reduction.

3. Bonneville is considering unbundling the services it provides such as transmission, storage, load-shaping and integration services. What are the potential benefits and drawbacks of unbundling? If Bonneville pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some Bonneville services that cannot be unbundled?

Are you aware of any examples in either the public or private sectors of unbundled wholesale power services?

Unbundling could provide Bonneville with a new revenue source for services if it is presently providing these services at no or little charge. The bundle of services presently provided to full requirements customers are paid for through the Priority Firm rate on a average system cost basis. However, unbundling could lead to market pricing which could further disadvantage full requirements customers. Also, if Bonneville is unable to correctly price these unbundled services, there will be an increase in the duplication of facilities and a move away from one utility planning.

4. How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must Bonneville do to ensure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection of fish and wildlife?

How can the region maintain the benefits of regional coordination and planning if resource acquisition an transmission become more decentralized as a result of tiered rates and unbundling?

Costs must follow the resource. That is, fish and wildlife costs associated with the hydroelectric system must be recovered by the tier I rate. All new resource costs, including conservation must be recovered by the tier II rate. Transmission system costs must some how be allocated among the tiers and the unbundled services. Under this scenario, regional planning will certainly be diminished because the decision making for resource development and transmission system requirements can and will be made independent of Bonneville.

5. Should the variable rate for the Direct Service Industries (DSI) be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional rate payers of continuing to provide this variable rate.

What is the current value of reserve (VOR) of the first quartile of the DSI allocation? What is the current VOR of the second quartile?

The variable rate should definitely be eliminated. The circumstances today are different than when the variable rate was started. We are no longer in resource surplus and subsidizing the aluminum companies is costing us all dearly. While the variable rate has been a net benefit to Bonneville's non-aluminum smelter customers (an additional $23.5 million from 1986 through 1st quarter of FY 1993) this trend has been greatly reversed since FY 1992. With the world price of aluminum expected to remain at low levels and the power deficit continuing, the variable rate will soon become a net loser, if it is not already.

The current value of reserves is about $60 million per year. Of this, $30 million is for the second quartile, which should be eliminated. An additional $10 million could be removed by updating the calculation used for the top quartile reserve. The resulting value for reserves that more accurately reflects what we are actually getting is about $20 million per year.

6. Should the irrigation discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional rate payers of continuing to provide this discount.

7. Should the low-density discount be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional rate payers of continuing to provide these discounts.

8. Are there any other subsidies or discounts that Bonneville provides to certain customers that should be eliminated?

Bonneville's discounts are an attempt to equally position the customers of the various preference utilities that are otherwise disadvantaged because of circumstances in their service territories. For example, through the irrigation discount, Bonneville recognizes that there are utilities who have a large proportion of irrigation load and that their well being is closely tied to the well being of their irrigating customers. Similarity, for the Low Density Discount, utilities who are disadvantaged by having sparse populations and/or high debt in relation to sales volume receive a discount to more equally position their customers with others in the region. These discounts are a matter of equity and should remain.

9. Should the provisions in the power sales contract which allow some utilities to be reimbursed by Bonneville for lost revenue when a voluntary curtailment is implemented be eliminated? If so, why? If not, why not?

Yes. Under the regional "Share The Shortage" Agreement, Bonneville's customers will be asked to curtail their sales so that other higher priority loads can be served. Because some of these customers are requirements customers, any saved power ends up on Bonneville's system to be sold at marginal rates. The curtailment of these loads reduces the new operating revenue of these utilities and they should be reimbursed for that net revenue loss.

10. How should the long-term power contracts that Bonneville is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

Entirely too much attention is being given to Bonneville's non-customers in regard to what they think should be in the utility's power sales contracts. Not enough consideration is being given to merely extending the present contracts.

11. It has been suggested that the residential exchange program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

The residential exchange should be eliminated because it unjustly enriches the customers of private power companies, represents an income transfer in the region of some $200 million annually and it is a subversion of public preference.

12. What part should Bonneville's existing resource acquisition programs play in Bonneville's competitiveness initiative, both during a transition period and after Bonneville has adopted some of the changes is is considering?

BPA'S resource acquisition activities will play an important part in the success of its competitiveness initiative. We believe that the change must begin immediately. BPA has a total 505 (388 BFTE & 117 CFTE) combined Bonneville and contractor FTE work on a variety of BPA resource acquisition activities. This means that there are approximately 5 Bonneville and Contractor FTE for every public utility in the region. This staff is larger than

the conservation staff of most of BPA's customers. Some will tell you that this is a large number of people because conservation is labor intensive. Depending on how you implement conservation, it can be labor intensive at the retail utility level but BPA is a wholesale power supplier. It does not implement conservation programs directly with retail customers. Instead BPA must work through its public utility customers to deliver conservation resources.
We submit that the primary reason that BPA's resource acquisition activities are so people intensive is because of the way that the agency approaches resources. BPA has established a paradigm that requires elaborate tracking, expensive procedures and continual tweaking. BPA's current system has produced a conservation acquisition system that carries a 40% overhead loading. This means that 40 cents of every dollar that BPA spends on conservation actually goes to support the organization. This is much too high!

During the transition period from the current to a new BPA:

a. We believe that BPA should begin immediately trying to become the type of organization that they want to be in the future. (Customer-focused, market-driven, cost conscious, and results-oriented.)

b. Unless BPA begins to transition now there will be tremendous upheaval and dislocation when the time finally arrives.

c. We believe that the "transition" period should be a time for experimentation and testing of different approaches to conservation in particular.

d. We believe that this experimentation should challenge our preconceived notions about the current approach to conservation resource delivery. In this transition period BPA could look to a more flexible approach to conservation by its customers. During this two year period we believe a moratorium should be placed on conservation program redesign and conservation program evaluation. In fact, we believe that the very well educated and knowledgeable Bonneville employees who work in these functions could make productive contributions elsewhere in BPA.

e. This approach could take several forms, a) issuing a RFP for conservation resources from utility customers; b) piloting different implementation strategies; or c) allocating the conservation budgets directly to utilities and challenging their creativity in conservation resource delivery by encouraging innovation and process improvements.

f. Any or all of these approaches to the conservation resource could work. We believe that the answer to cost effective conservation and resource delivery is the direct involvement and decisionmaking of every General Manager and public utility Board of Directors in the region.
g. It is the direct involvement of these local decision makers that will produce the best results for the Northwest.

In the future we fully expect BPA's resource acquisitions to look quite different. If, despite many attendant problems we implement a form of tiered rates in the region, we expect BPA to develop resources only when asked. We expect that many of the approaches to resource development will change radically. Because there are so many different questions surrounding all of these future scenarios we support making the current activities as cost effective as possible.

13. Please provide any other suggestions regarding actions that would make Bonneville more competitive or cost-effective.

We believe the alternatives to tiered rates that have been proposed above will lead to a more competitive Bonneville without all the divisiveness that will surely develop with an allocation of the FBS. Under our proposal, regional planning as it now exists would remain in place. The problems surrounding Bonneville can be fixed without tearing apart a system that has served the region well for the past fifty years. Let us not kill the goose that laid the golden egg, let us merely fertilize it.

STATEMENT OF K.C. GOLDEN

Mr. GOLDEN. Let me pull off my coat so I can distinguish myself from the men in blue a little bit. I do not want you to get the wrong impression. [Laughter.]

Thank you, Mr. Chairman and Congressman LaRocco. My name is K.C. Golden and I am the director of the——

Mr. DEFAZIO. Now they are taking off their coats at the other end here. [Laughter.]

We may get into some more interesting rebuttal here.

Mr. GOLDEN. I am the director of the Northwest Conservation Act Coalition. We are a region-wide alliance of public interest organizations and we have appeared before you before and appreciate the opportunity to do so again.

We fervently support the effort to make Bonneville a more efficient agency and more effective at reaching its goals. But frankly, we have to question the sudden frenzy over the proposition that Bonneville is in imminent danger of losing its competitiveness and turning into the mere carcass that Mr. Drummond described. BPA is still by a wide margin the lowest cost wholesale power supplier in the region and in the West for that matter. I think that Mr. Drummond's own testimony supported that inadvertently by his insistence, and other panelist insistence, that BPA stay with cost-based rates rather than value-based rates. That is an indication that the value of BPA's power is significantly higher than its cost. Market-clearing prices for BPA power are significantly higher than what BPA customers now pay, and I think we all know that.

It is ironic in fact, I think, that some of the customers who are beating their chest the loudest about the new robust competitive market forces out there are those who would be the first to fall off in a truly free market competitive environment. In a truly free market competitive environment, there would be no regional preference; there would be no public preference; there would be no irrigation discount. And we certainly would not be selling power to direct service industries at half of its market-clearing price.

Having said all of that, we frankly welcome a good dose of market pressure on the BPA System. I think the BPA system has become lazy and complacent. When I say the BPA system, I include the agency and its customers. I think market pressures will help awaken us to the fact that we cannot keep diluting our inexpensive hydropower resources forever with expensive mistakes and expect not to have to pay for it. We cannot continue to subsidize uneconomic use. And we have to awaken to the necessity to move from least-cost planning relative swiftly to least-cost action. I think the market will help us do all those things if intelligently applied.

But the market is not an end in itself; the market is a mechanism. The market cannot tell us what our goals are; it can only help us achieve them more efficiently. The comparison that comes to mind is the Clean Air Act. Market forces have been unleashed under the Clean Air Act to achieve pollution reduction goals as efficiently as possible. I think it is working quite well. But we did not ask the market to tell us what is the appropriate amount of sulfur dioxide—that was a policy goal. Having set that policy goal, we did unleash the invisible hand to get us there as efficiently as possible, and I think that analogy applies here as well.

Bonneville's goals are the goals of the Northwest Power Planning Act. I think those goals encompass the goals of Bonneville's original legislation—but bring them out of the 1930s into at least 1980, and I believe that they are still every bit as relevant today.

Frankly, many of Bonneville's customers would have preferred an Act without fish and wildlife goals, without environmental goals, without conservation mandates, and frankly without a Power Planning Council at all. There were original proposals that had a governing board that consisted entirely of utilities, and they did not prevail in that position for a lot of good reasons.

Now I think under the mantle of competitiveness, although the market pressures the people describe are real, but under the notion that Bonneville is imminently in danger of losing its competitiveness, I think many of those customers frankly are trying to reverse the Act's verdict on those other purposes. I will give you some of the signals that I hear that suggest to me that that is the case.

Bonneville in 1991 adopted a mission statement that said, To make Bonneville the most competitive and socially responsible power supplier or utility system in the Nation. I do not think those two goals are in conflict with one another, but frankly, I find it alarming that the second half of that goal seems to have disappeared without a trace from Bonneville's rhetoric.

There is an influential customer review group looking at Bonneville's programs right now and making, I think, some pretty important decisions. There is no parallel group for non-customers, for Congress, for the Power Planning Council, for public interest groups, for anyone but customers.

There was recently completed a survey called "From Insight to Action: Customers' Values and Satisfaction." I did not receive a survey about non-customers' values and satisfaction, or about retail customers' values and satisfactions. And I assure you that the Power Planning Council and probably yourselves did not either.

In a recent letter, the head of the Oregon Rural Electric Cooperatives railed against the Power Planning Council because they are out of control on fish and wildlife issues and that Administrator Hardy appropriately made some decisions that put the customers firmly in control of the region's energy future. Well, I do not think that is what the Act said. I think the Act said that the Council and the people of the region would be in control of the region's energy future.

There are a number of other examples. Probably the most colorful description of the appropriate role of public interests in Bonneville planning decisions was delivered by Harney Electric Cooperative, and I urge any of you who have not seen that colorful description to get your own copy.

There is a persistent emphasis in Bonneville, and among its customers now, on emphasizing business relationships and de-emphasizing political relationships, which means relationships with you and me and the Council and anybody besides its wholesale customers. Well, Bonneville is of course not a business, as you have heard from many of the folks here today. I think Bonneville can learn a lot from businesses about how to run a tighter ship, about how to be a more effective and efficient agency, but let us pursue this business analogy a little bit. When a business says the cus-

tomer is king, that is of course a marketing ploy for the customers, and we all take it with a grain of salt. Businesses are not ultimately accountable to their customers; they are ultimately accountable to their shareholders. And the shareholders of the Bonneville system are the customers' customers, the retail customers, the citizens of the Northwest, and arguably the taxpayers of the country who have made an investment in the Northwest hydrosystem. I do not hear any mention of the shareholders' interests in all these business analogies and I would assert that it is time for a shareholders' meeting.

We put the goals of the Act there for very good reasons, and I firmly believe that those reasons are not inconsistent with the competitiveness. Those goals preserve the region's comparative advantage by having us use our hydropower resources as efficiently as possible. They preserve our incomparable natural resources which is a good part of what is attractive about this region over other regions. They attempt to restore our economically and culturally valuable fisheries. And frankly they reduce the potential for paralyzing conflict among all the parties seated here at the table today about what our energy future looks like. I think in sum they enhance the competitiveness in the Northwest economy by making it a better place to live and work and by giving us a more rational energy system. That is the kind of competitiveness that I think Congress envisioned when it wrote the Act, and it is the kind of competitiveness that we can still endorse and the region can still live with.

I would urge you to reaffirm that definition of competitiveness at a time when it is frankly under siege. I think it is especially critical to do that because that definition, instead of pitting the shareholders against the customers, brings the shareholders and the customers together, and we have had a lot of success working together over the last ten years. But frankly the move to adopt a definition of competitiveness that strongly favors the customers over the shareholders will pit us against each other in the way that we were in 1980, and I do not think that was particularly constructive from many of our perspectives.

I want to thank you for holding this hearing and particularly for bringing these somewhat arcane technical issues into a political spotlight and shedding a sense of political consequence on these decisions, which deserve every bit of that sense of political consequence. Thank you very much.

[Prepared statement of Mr. Golden follows:]

Testimony of K.C. Golden, Executive Director
on behalf of the
Northwest Conservation Act Coalition
before the

House Committee on Natural Resources
Bonneville Power Administration Task Force

September 25, 1993
Eugene, Oregon

Mr. Chairman, thank you again for the opportunity to testify before the BPA Task Force. My name is K.C. Golden. I am the Executive Director of the Northwest Conservation Act Coalition, a regional alliance of public interest organizations and utilities that is dedicated to the successful implementation of the Northwest Conservation and Power Planning Act of 1980. Our goals are laid out clearly and compellingly in the Act's purposes (and I paraphrase here):

> (1)(A) To encourage conservation and efficiency in the use of electric power;
>
> (1)(B) To encourage the development of renewable resources within the Pacific Northwest;
>
> (2) To assure adequate, efficient, economical, and reliable energy services;
>
> (3) To make the public and its state and local and tribal governments full partners in building a regional energy future that emphasizes conservation, renewable resources, and environmental protection;
>
> (4) To distribute the costs and benefits of the regional power system fairly; and
>
> (6) To protect, mitigate, and enhance the fish and wildlife resources of the Columbia River Basin.

Although NCAC fervently supports the effort to make BPA a more efficient agency, we must begin by questioning the basic premise of the competitiveness initiative. Many of BPA's customers contend that BPA is in imminent danger of suffering a massive loss of load to lower cost competitors. These competitors, the thinking goes, can supply energy more cheaply because they are not saddled with BPA's environmental and conservation responsibilities and because they do not have the looming threat of repayment reform. As customers flee the system, rates will rise even more dramatically, causing the infamous "death spiral."

We submit that this scenario is entirely implausible. BPA is, by a very wide margin, the lowest cost wholesale power supplier in the West. Those who have preferential access to BPA power are well aware that the market will bear substantially higher prices, and that a formidable array of utilities outside of the Northwest would gladly trade places in the queue. At a recent meeting of the Northwest Power Planning Council, University of Kansas Professor Doug Houston, an outspoken opponent of utility-sponsored conservation and environmental initiatives, confirmed the magnitude of BPA's competitive advantage. Professor Houston estimated that BPA rates would **double** if left unregulated. In other words, the market clearing price for BPA power is much **higher** than current levels, and those who claim easy access to cheaper alternatives are simply posturing for negotiating leverage.

Having said that, NCAC very strongly supports the notion that BPA can and must accomplish its objectives much more efficiently than it currently does. We welcome the advent of market pressures that will awaken the Northwest utility industry to the reality of rising marginal costs and the urgent need to develop least-cost energy resources. BPA and its customers have been lulled into complacency by the luxury of a pool of inexpensive hydropower so vast that it was able to absorb enormous financial mistakes and still yield the lowest rates in the nation. We strongly encourage the introduction of market signals that reinforce a message that BPA and its customers desperately need to hear: We simply can't afford to postpone least-cost resource development and subsidize uneconomic use any longer.

Market forces can and should be used to help BPA and its customers come to grips with the reality that our inexpensive hydropower resources are finite and the necessity to move swiftly from least-cost **planning** to least-cost **action**. We support the introduction of tiered rates; elimination of subsidies for uneconomic use; and contractual commitments to hold customers accountable for the costs and benefits they bring to the system.

Market mechanisms can be of enormous service in helping BPA reach its goals more efficiently and effectively; **the market cannot, however, tell BPA what its goals are**. Embracing market forces **does not** mean sweeping aside all policy objectives in favor of minimizing short-term rates, as some customers have implied. Many customers contend that BPA's competitiveness can only be assured if it focuses myopically on marketing power and considers all other objectives - including the achievement of the Act's purposes - as costs of business to be minimized, rather than goals to be achieved. We should hardly be surprised that customers define competitiveness this way, but we must not allow BPA to do so.

The people of the Northwest will be well-served by a vigorous competition in which the winners deliver energy services at the lowest total cost. However, we will not accept a destructive competition to see who can most artfully circumvent the goals of the Act to hold down short term prices. Nor can we accept competition that pits the ability of a few energy-intensive industries to minimize rates against the ability of the region to thrive and prosper. That kind of competition may enrich a few, but it impoverishes the region by eroding our capacity to build the efficient, affordable, environmentally sound, equitable energy system envisioned in the Regional Act.

We clearly detect in BPA's "competitiveness" initiative an effort to undermine the provisions of the Act that make BPA accountable to the public, to Congress, to the Power Planning Council, and indeed, to anyone but its wholesale customers. Three years ago, BPA adopted a mission statement in which it aspired to be "the most competitive and socially responsible" power system in the nation. We do not believe that those two goals are in conflict. Still, we find it conspicuous that the second half of that mandate seems to have vanished without a trace from BPA's rhetoric.

Although the competitiveness initiative is proceeding largely behind closed doors, we have seen enough to understand where it's heading. Perhaps the most telling sign is the persistent focus on emphasizing "business relationships" (i.e., relationships with utilities and the Direct Service Industries) and de-emphasizing "political" relationships (i.e., relationships with the public, Congress, state and local governments, tribes, agencies, public interest organizations, and the Council). BPA management proclaims that its goal is to run the agency "like a business." Bonneville is, of course, not a business but a public agency with a mandate to serve the public interest. Still, we accept the proposition that BPA could learn a great deal from private entities about how to run a leaner, more efficient organization.

Many customers seem to believe that running it like a business means catering exclusively to the desires of its wholesale customers, primarily by minimizing wholesale prices. But successful businesses cater to their customers only insofar as doing so serves the interests of their shareholders. If we pursue the business analogy to its extreme, we inevitably conclude that businesses are not created for the primary purpose of satisfying their customers; they are created to add value for their owners. These purposes are generally compatible and often inseparable, but when they conflict, no business will pursue its customers' goals at the expense of its shareholders. Because BPA is a public entity, its shareholders are its customers' customers, the retail consumers, the citizens of the Pacific

Northwest. To the extent that all Federal taxpayers have made an investment in the Columbia River system, one might argue that they have an ownership share as well. In all the business rhetoric emerging from the competitiveness initiative, we find no reference to the interests of the shareholders.

Most of BPA's customers opposed the provisions of the Act that make BPA accountable to the public and public officials. They opposed provisions that make BPA responsible for the pursuit of values larger than their own bottom line. They made plain their preference for a Planning Council composed entirely of utility representatives and for an Act without fish and wildlife, environmental, conservation, and public involvement mandates. Their position was clear, but they did not prevail because their position served the utilities' interests at the expense of the public interest.

Now, under the guise of "competitiveness," those same customers are trying to reverse the Act's verdict, without the bother of actually going to Congress to get it repealed. BPA has formed an influential "customer review group" to re-evaluate its programs; there is no "review group" for non-customers. As part of its "reinvention," BPA recently completed a comprehensive survey of customers entitled "From Insight to Action: Customers' Values/Satisfaction;" there was no comparable survey of the public, public officials, states, tribes, agencies, public interest groups, or anyone else for that matter. The customers make no bones about their belief that they, and they alone, have the right to define BPA's mission and policies. Judging by who they have invited to the "reinvention" party thus far, we can only conclude that BPA concurs with the customers' judgment.

The goals of the Act are there for good reasons, and those reasons are not inconsistent with competitiveness. They direct the region toward energy programs that preserve the Northwest's comparative advantage by using our inexpensive hydropower as efficiently as possible; protecting our incomparable natural resources; and restoring our economically, culturally, environmentally valuable fisheries. They reduce the potential for paralyzing, expensive conflicts over energy resource development by making the public and its state, local, and tribal governments full partners in the region's energy planning process. They are goals, in short, that enhance the competitiveness of the Northwest's economy and the attractiveness of the region as a place to live and work. That is the kind of competitiveness that Congress had in mind when it passed the Act. We would urge this Task Force to reaffirm that definition.

We believe that this is a crucial moment for Congress to reinforce the Act's vision of an economically and environmentally sound regional energy program. As we noted, we are eager to apply market forces as a way to focus BPA more decisively on its fundamental purposes. But, at the same moment that we embrace market mechanisms to help us accomplish our goals more efficiently, we must actively and unambiguously reassert those goals. Without our combined and determined effort to reaffirm these goals, BPA seems prepared to adopt a definition of competitiveness that strongly favors the customers over the shareholders. It's time for a shareholders meeting.

In adopting the Act, Congress recognized that preserving the long-term economic and environmental well-being of the region means using the output of the Columbia River system efficiently, protecting our natural resources, and ensuring that decision-makers are held accountable to those who must ultimately pay the bill. Congress was right in 1980 and still is. But being right won't help your constituents much unless you reaffirm those goals, quickly and decisively, as non-negotiable elements of the "reinvention" process.

Thank you again for soliciting our input, and for your determination to hold BPA and its wholesale customers accountable to the public interest.

The remainder of my written testimony is directed toward the issues you raise in your invitation to testify:

Question 1: As discussed above, if we define "competitiveness" as the ability to market wholesale power at a competitive price, BPA is in no imminent danger. Nevertheless, we believe strongly that BPA should more effectively and efficiently focus its programs to achieve the goals set forth in the Regional Act. Most importantly, BPA must be reminded that it ultimately serves the long-term public interest, not the short-term interests of its wholesale customers.

Question 2: NCAC proposed tiered rates in the 1993 rate case, and reached a settlement with BPA that led to the current negotiations. We believe strongly that marginal cost price signals promote economic efficiency. We do not, however, believe that tiered rates are equivalent to or can substitute for strong utility-sponsored conservation programs. On the contrary, they will increase demand for those programs. In parts of the country with substantially higher rates and weak conservation programs, cost-effective conservation opportunities are foregone more often than they are seized due to a formidable array of market barriers. Tiered rates will only marginally diminish those barriers. Conservation programs will be more successful because of tiered rates, but they will also be more necessary.

We propose the following principals for tiered rates:

• All customers should face BPA's regional marginal cost including the external costs of the marginal resource.

• All customers who share the benefits of the publicly-owned Columbia River system share the responsibility for its stewardship. Tiered rates must be structured so as to strongly support the goals of the Regional Act.

• All customers should pay their cost of service.

• Public preference should be maintained and not extended to the Direct Service Industries.

We believe that tiered rates will encourage economic development by promoting economic efficiency and least-cost resource resource acquisition. The tiered rate proposals under discussion relate only to wholesale rates; how these costs are passed on to retail consumers is largely within the discretion of the retail utilities. We have proposed for discussion that tier 1 allocations could grow with population growth in preference customers' service areas, accompanied by a commensurate shrinking in the DSIs' share of FBS and exchange resources. But with or without this sort of adjustment, retail utilities are free to set retail rates autonomously.

Tiered rates may in some respects "allocate" federal base system resources. This is one of the most compelling reasons that they must be accompanied by contractual obligations to the implementation of the Regional Act. (See answer to question 4.) We do believe that customers should enjoy certain property rights that current contracts deny or dilute. For instance, under existing contracts, independently conserved energy amounts to a theft of federal property, while customers may do whatever they wish with the output of their generating resources. Tiered rates and contracts should encourage the development of a market in conserved power by allowing customers to reap some or all of the market value of their conservation efforts.

Question 3: The principal advantage of unbundling services is that it allows BPA to more accurately and fairly allocate costs while allowing customers to choose only those energy and non-energy services that integrate well with their own systems. Unbundling is likely to favor the interests of large utilities with sufficient market power and expertise to readily take advantage of unbundled services. Smaller utilities may form consortia that can overcome some of these handicaps.

Question 4: Without strong safeguards and legally binding commitments to the purposes of the Regional Act, tiered rates and unbundling may make it more difficult to hold utilities accountable to those purposes. By and large, we believe that it is appropriate to assign environmental costs to the resources that cause the impact in question, regardless of how these resources are allocated to serve loads. Thus, fish recovery costs and nuclear decommissioning costs should be added to the cost of the FBS. Carbon dioxide and air pollution costs should be included in the costs of new and existing fossil-fueled generation, etc. Whether those costs fall into tier 1 or tier 2 depends on how resources are allocated among the tiers.

If resource acquisition and transmission become more decentralized, BPA must play a stronger role in negotiating power sales contracts and rate structures to ensure that any customer that develops new resources is held accountable to the goals of the Act. We have a number of suggestions as to how this should be accomplished, some of which are listed below. But, if these provisions are to be adopted, BPA must assert itself in these negotiations as an effective steward of Columbia River Basin resources and a tireless advocate for the goals of the Regional Act.

Some of our concrete proposals include:

• Pricing unbundled integration services (load following, transmission, reserves, etc.) 10% lower for integration of customers' conservation and renewable resources, to reflect the first two purposes of the Act.

• Requiring all BPA-served utilities that wish to develop their own resources to write least-cost plans in open public forums, using consistent values for environmental externalities.

• Giving authority to the Council to reduce customers' first tier allocation by the amount of any new generating resource that is not consistent with the Plan.

We are open to other suggestions as to how resource acquisitions should conform to the Act's priorities and the regional least-cost plan. But, having worked so diligently to develop a least-cost planning process in which all interests are heard and the public interest comes first, we are not willing to accept resource development that flaunts the provisions of the Plan. We do work very hard, however, to make least-cost resource development consistent with the financial interests of utilities, and will continue to do so.

Question 5: We believe that the variable rate should be eliminated when it expires in 1996, unless DSIs can pay variable rates and still pay the full cost of service **and** similar deals are offered to other industries. The variable rate shifts some of the market risk of the aluminum industry to the rest of the region's consumers. At current world aluminum prices, the rest of us subsidize the industry to the tune of around $11 million per month through the variable rate. Even if the variable rate were a wash, it transfers enormous value from customers as a whole to the industry by transferring business risk.

Subsidies of this type induce undesirable market distortions. They may "save" - or at least postpone the loss of - aluminum industry jobs. But that money comes from other consumers, businesses, and industries with employees of their own. Very few uses of this money and no uses of this energy would create fewer jobs than aluminum smelters do. Aluminum jobs belong to real people, and we are sensitive to their needs and economic conditions, but we do not believe they should be favored over the more diffuse, but still real economic needs of the other businesses and employees that pick up the tab for the variable rate.

Our testimony in the 1993 rate case provides a detailed analysis of the VOR and the miscalculation of its value due to dated interest rate assumptions and the fact that BPA pays for nearly twice the reserves they actually get, according to BPA's own witnesses. We have provided that testimony to the Task Force. The subsidy for overpayment of the VOR amounts to approximately $40 million per year.

Questions 6 and 7: We have analyzed both the irrigation discount and the low-density discount in our rate case testimony, which we have provided to Task Force staff. We believe that the irrigation discount should be eliminated and the low-density discount modified to eliminate disincentives for efficiency.

Question 8: The largest subsidy is sanctioned by the Act. Section 7 (c) (1) (b) keeps the rates charged to the DSIs, even without the variable rate, artificially low. The resources described in the Act which serve DSI load come mainly from the purchase of power from the IOUs through the exchange. This power is priced at the exchanging utilities' average system cost, presently about 34 mills. Even without the Variable Rate, the DSIs would get this power for about 27 mills. The overall subsidy amounts to hundreds of millions of dollars each year.

The framers of the Act forecast the price of service to large industrial customers of public utilities to grow rapidly as New Large Single Loads came on line. This would have raised rates under 7(c)(1)(b) to the DSIs as well - so much so that the DSIs were expected to essentially pay for the cost of the exchange. However, utilities and industries have largely circumvented the New Large Single Load provisions of the Act. This subsidy may be legal, but it is a subsidy nonetheless, since the DSIs do not pay the cost of their service. Its cost is more than the irrigation, low density, and variable rate discounts combined.

NCAC suggests that the DSIs be served with more interruptible power, as provided for in Section 7(c)(2), at much lower cost to BPA's other customers. Alternatively, their allocation of firm power could be allowed to shrink with the growth in preference customer loads or the loss of FBS resources. BPA must take a strong role in negotiating DSI contracts that are fair to the rest of the region's consumers, remembering that they are not legally obligated to offer any contracts for direct service or to offer services equivalent to those received by preference customers.

Question 10: BPA should make access to the enormous benefits of the regional system conditional upon recipients' good faith participation in the regional program. By "program" we mean generically the pursuit of the Act's purposes and the implementation of the Regional Plan. Contracts should allocate the costs and benefits of the system fairly, with no special deals for particular customers unless those customers provide commensurate benefits. In signing long-term contracts, BPA allocates the benefits of a public resource, and must do so with a keen eye toward protecting the long-term public interest. We have not yet developed model contractual provisions that would serve these goals, but we believe that the contracts must reflect the principles above. The contracts are probably the single most important place to ensure that those who benefit from the regional

system pay for its costs and participate in programs that preserve those benefits for future generations. We have attached our scoping comments for the Power Sales Contracts EIS to our testimony.

Question 11: NCAC has not yet formed a position on whether or how the exchange agreements should be changed, but we expect to do so before this task force concludes its deliberations.

Question 12: Coalition members are still debating the appropriate role for BPA in resource acquisitions, and we will submit our thoughts on this issue to the Task Force before your deliberations conclude. But we do feel strongly that BPA must not abandon its efforts to acquire all cost-effective conservation unless and until a superior method to achieve that goal is in place. At the last hearing, we argued that BPA was already falling far short of its statutory obligation by chronically underfunding conservation. The situation appears to have deteriorated further since that time.

Question 13: We are participating actively in the function-by-function review to find efficiencies in BPA's programs. But again, we are ultimately more interested in the region's long-term economic and environmental well-being than we are in minimizing short-term rates. BPA must become more efficient, but more importantly, it must more efficiently serve the public interest, as articulated in the Regional Act.

Northwest Conservation Act Coalition

Attachment to NCAC Testimony: Scoping Comments for Power Sales Contracts

Sept. 13, 1993

Bonneville Power Administration
Public Involvement Manager
P.O. Box 12999
Portland, OR 97212

Dear Ms. Lynn Baker:

The following is a supplement to oral comments presented at the Commercial Services and Rates Scoping meeting on Aug. 24th in Portland.

The Northwest Conservation Act Coalition (NCAC), 217 Pine St. Suite 1020, Seattle, WA 98101, founded in 1981, is a region-wide alliance of conservation and consumer advocate organizations, utilities, businesses and citizen activists seeking a clean, affordable energy future for the Pacific Northwest and British Columbia. We appreciate the opportunity to comment on BPA's proposed commercial services and rates.

The purpose of these comments, quoting from BPA's announcement, is: "The EIS will help BPA choose the best methods for providing electrical service to its Pacific Northwest customers, utilities and industries that buy wholesale power from BPA." To judge which method is "best," we must know what the standard is we are comparing against. Does BPA mean cheapest? Cleanest? Most reliable? Exactly what are BPA's goals and objectives for providing electrical service?

This question points to a major failing of the current discussion of alternatives. That is the mixing of two logical constructs: the goals of the contracts, and the means of achieving these goals. It is extremely important to separate these two discussions, but BPA, and many of the customers, have blurred them together. The former is a value-laden decision while the latter is a value-free discussion. For example, the Market-based alternative is viewed by many as a goal as well as an implementation measure. These parties see the promise of low rates and customer indepen-

dence often found in free markets as valuable. However, their goals are low rates and customer independence, not free markets. The market is only a means of attaining the goals.

It would be extremely helpful if BPA and others would be more careful in maintaining this logical separation. And in fact, the PSC Working Group was initially cognizant of this when it posed its first, "Overarching" issue: "What is the purpose of the Power Sales Contract?" However this most fundamentally important question seems to have disappeared from everyone's screens. Summaries of discussions, for example, typically start with question A1 (What is BPA's role as developer...). Indeed, the scoping alternatives no longer even mention this as an issue!

But this is the most important issue. All other questions are just about the best means of attaining our goals. NCAC therefore suggests that the scoping analysis proceed in a two-step process. First analyze the possible different goals of the contracts, and then evaluate the impacts on these goals of each implementation option.

What are the different possible goals which should be examined? NCAC submits that BPA's goals and objectives are easy to identify. And, they're not subject to debate or up for negotiation. The purposes are clearly identified in the Pacific Northwest Electric Power Planning and Conservation Act of 1980.

"Such purposes are:

(1) to encourage, through the unique opportunity provided by the Federal Columbia River Power System--
(A) conservation and efficiency...
(E) the development of renewable resources...;
(2) to assure...an adequate, efficient, economical and reliable power supply;
(3) to provide for the participation and consultation of the States, local governments, consumers, customers, users of the Columbia River System (including Federal and State fish and wildlife agencies and appropriate Indian tribes), and the public at large...; and...

(6) to protect, mitigate and enhance the fish and wildlife, including related spawning grounds and habitat, of the Columbia River and its tributaries...."

But many others do not agree with these goals. PPC, for example sees the purpose differently:

"The contracts should facilitate the purchase of power by the customers, should facilitate resource development by the customers, should address the integration of customer resources with the purchase of federal power, and should assure compliance with appropriate environmental requirements."

The ICP:

"Establish terms and conditions for purchase of power and certain services by customers from BPA."

WPAG:

"To establish the power purchase relationship between BPA and the customer, and provide an orderly method by which that relationship can respond to change over time."

NWPPC:

"...The contracts must reflect Bonneville's obligations to acquire conservation and generating resources that are consistent with the...Act and the power plan...and to implement the fish and wildlife program developed by the Council. The contracts should incorporate the customers' commitment to cooperate with Bonneville in meeting these obligations."

DSIs:

"The contract should specify the rights and obligations of the signatory parties regarding the purchase and sale of power....It should not be designed to impose 'social' values....The DSIs also have an interest in an adequate, reliable and affordable power supply....the DSIs need the flexibility to respond to changing conditions. Contracts burdened with social conditions are likelyy to conflict with changing laws and would certainly be less flexible."

It is evident from the above that the parties have differing views, to say the least. Most of the customers' (Some IBC utilities being the exception) goals are radically different from those in the Act. They would, in fact, need amendments to the Act, to be implemented. However, in a scoping exercise even actions requiring legislative changes should be considered, and NCAC is more than willing to revisit the goals of the Act

for this discussion. We also feel it is beneficial to get these "goal" arguments out in the open, rather than having them remain hidden in discussions of various implementation options.

We see three general "Goal Alternatives." The first is the goals of the present Act, the status quo. We are calling this the "Regional Goals" alternative.

The second, called the "Lowest Cost" alternative is a rewrite of Sec. two of the Act to basically read,

> The purpose of this Act is to assure the Pacific NW the cheapest possible power supply without regard to environmental or other externalities, giving no advantage to conservation or renewables and protecting and enhancing fish and wildlife only to the minimum extent required by law.

The last could be called the "Customer Autonomy" alternative. It would also require amending Sec. 2 of the Act to generally say,

> The purpose of this Act is to assure customers of BPA the most freedom to make their own resource decisions without regard to any regional needs.

(Obviously this third goal can also be an implementation option, but in this context we mean the goal of autonomy as a good in itself, not as a tool to achieve some other goal.)

It is obvious that many customers want different goals than those in the Act as the purpose of the contracts. So for their sake we urge BPA to study the impacts of having these different goals. How would the contracts look if the Act were rewritten as we've suggested? For our sake, we look forward to having these different goals, which are now only implicitly acknowledged, explicitly discussed and defended.

OUR RECOMMENDATION: Scope the overarching issue--What is the purpose of the Power Sales Contract?--using the three alternatives presented above.

(We believe that ultimately the public and Congress will reject any

substantial change in the purposes for which BPA is supposed to run the power system. Thus, until the Act is changed, BPA's goals, which it must seek to implement through its rates and contracts, are not negotiable. In practice this would mean that BPA would ask of every action it takes: Does this action further the goals of the Act? And BPA would ask of every service it provides: How can we structure and price this service so that those using this service will be encouraged to further those goals?)

* * * * *

At this stage of the EIS we are not required to choose between the alternative goals, however. BPA's next task is to evaluate each of the implementation option's impacts on each of the above three goals. Thus the Market-Based option might do very well achieving goals number 2 and 3, but badly on number 1.

This is the logical place to begin analyzing BPA's scoping alternatives. The rest of our comments will be specific implementation options which we feel are missing from the current analysis.

OUR RECOMMENDATION: Evaluate each implementation option--Central Plan, Market-Based, Minimum BPA, etc.--against each of the three goals described above.

(We would like to start with one complaint. The very term "Central Planning" is perjorative, suggesting the worst sort of Communist bureaucracy which brought down the Soviet Union. Perhaps the label, "Regional Coordination" would be less value-laden.)

RESOURCE DEVELOPMENT

Most tiered rate options have a goal of encouraging/allowing customers to do what used to be Bonneville's "job" of resource acquisition. Under the "Regional Goals" alternative, BPA has certain mandates under the Act in this area. They must do planning, including externalities, follow the

resource priorities of the Act, and in general keep to the Council's Plan. Thus, any tiered rate structure which BPA used which has the effect of inducing customers to do acquisitions must be designed to continue BPA's goals in resource development. Under this goal alternative, BPA couldn't say, "Sorry, it's up to the customers now." Bonneville would have the responsibility to design rates which made sure that acquisitions were still best for the region as stated in the Act.

This issue is not moot. Some utilities have argued, for example, that existing laws, permitting and siting regulations already adequately prevent the acquisition of non-conforming (to the Plan) resources. Thus, they say, there is no need for the PSC to say anything more than "everyone must obey all laws and regulations." They feel it would only add more red tape to the already arduous process. NCAC begs to differ.

We can state numerous instances where current regulations and laws would not prevent such acquisitions. Nevada, for instance, has almost no siting requirements. Coal plants could easily be built there by or for NW utilities. Idaho and Washington have no needs standard. In Washington non-conforming generating resources under 250 aMW can be built without much problem, <u>including hydro projects in the Council's protected areas</u>. Large utilities <u>are</u> required by Federal law to have least-cost plans, but even these plans do not have to be openly arrived at, include any externalities or the 10% conservation advantage. Thus it is imperative, if BPA adopts the "Regional Goals" alternative, that protections be in the contracts. We list some possiblities which should be investigated.

CUSTOMER ACQUISITIONS Require from utilities, in addition to having an openly arrived at Least-cost Plan (LCP), that:

a) this LCP be in compliance with the Council's plan and be approved by the Council,

b) and/or, this LCP include minimum externalities as decided by the Council,

c) and/or all generation acquisitions over 25 aMW be approved by the Council,

d) and, all hydro projects in Protected Areas be prohibited.

MECHANISM FOR ENFORCMENT A possible means to ensure compliance with the above requirements would be that any interested citizen could petition the Council that a customer was in non-compliance. The Council would agree or disagree within 60 days. If the Council ruled the utility was in non-compliance, BPA would then reduce that customer's first tier allocation in the amount of the non-complying resource.

ACCESS TO BPA'S TRANSMISSION GRID FOR CUSTOMER'S NEW RESOURCES

1) 1st priority access to conservation transfers,

2) 2nd priority access to renewables,

3) 3rd priority access to high-efficiency co-gen. (High-efficiency co-gen is defined as projects with a minimum of 10% thermal load and 50% thermodynamic efficiency of the non-thermal load.)

4) NO access to resources not complying with the Council's Plan.

5) In lieu of numbers 1-3 above, a transmission price differential of at least 10% for conservation transfers and renewables.

PRODUCTS AND SERVICES

Products and services needed by a customer to integrate its new resources would be given a price discount (10%?) for conservation and renewables.

DSI ISSUES

The future treatment of the DSIs is constrained by the Act and their existing contracts. In their present contract, section 12, it is explicitly stated that BPA is not "obligated" to offer a new contract, but must make best efforts to acquire enough resources to enable it to do so. And in section 7(c)(1)(B) the Act dictates the rate level which should be charged ("equitable in relation to the retail rates charged by the public

It is clear that the amount and interruptibility of power, as well as other terms and conditions of service are left open for negotiation. And again, "best efforts" must be defined. It is NCAC's strong opinion that "best efforts" is limited to obtaining power at a cost at or below the revenue received from the DSIs (adjusted, of course for the value of reserves made available). There must be no cross-subsidization by other customers.

Applying the "Regional Goals" alternative to the DSIs generates the following principle: The DSIs, being neither preference customers nor priority firm customers, should be served only under such terms and conditions as to provide benefit to the regional power system with the least environmental impact, subject to the restraints in the Act and their current contracts. In particular:

1) Insofar as the industrial consumers of preference customers may face tiered rates (directly or indirectly through their utilities), the DSIs should also face marginal rates reflecting the cost of New Resources dedicated to this class of service, thus providing an incentive for efficiency.

2a) The maximum size of the DSI's tier 1 allocation should be the amount of FBS or Exchange resource not needed for Priority Firm customers. As preference load grows or the FBS shrinks, for example, the DSI contract demand could be reduced accordingly. The rate for this allocation would be set by 7(c)(1)(B).

2b) A variation of this which should be examined is that any FBS or Exchange resource not needed for Priority Firm customers (beyond the minimum set in (3) below) would be offered for sale to anyone on the open market, including, of course, the DSIs.

3) The minimum size of the DSI's tier 1 allocation should be the level needed by BPA for reserves which cannot be obtained at a lesser cost through other means.

4) To encourage the most efficient use of energy, the DSIs should be allowed to buy and sell among themselves. In this way the least-efficient plants could sell their contract demand to the most efficient. As the overall DSI allocation of the FBS and Exchange resources shrunk due to failure of WPPSS #2, derating of the dams for fish needs, and/or growth or creation of new public utilities, this reselling among themselves would provide for the most efficient weeding out of the worst plants and the means and incentive for technological innovation for the best.

5) All customers should have the opportunity to bid to provide BPA's reserve requirements.

6) Service to the DSIs from the hydro system must be much more interruptible to allow operation of the dams for the benefit of fish.

RATE DESIGN ISSUES

Certain rate design options should be analyzed for their impacts on salmon. While tiered rates should encourage conservation in general, some other specific measures could benefit the fish with or without the implementation of tiered rates.

1) Eliminate, or restructure the irrigation discount so that irrigators see the full price ramifications of taking water from the river at certain times of the year. [See NCAC's rate case testimony.]

2) Restructure the Low Density Discount on a per-customer basis to encourage conservation. [See NCAC's rate case testimony.]

3) All rates should include water availability adjustments to reflect the value to the fish of water used for power generation. This adjustment (for wet or dry years, high or low snowpack) could be superimposed on fixed seasonal adjustments.

4) BPA should examine the alternative of offering contracts at a favorable rate to any taker who is willing to be fully interruptible in the fall and winter.

5) Because of BPA's equitable treatment obligation [Sec. 4(h)(11)(A)(i)], BPA should examine apportioning the FBS to the anadromous fishery, apart from and prior to any contracts or sales are entered into; or, issue a "fish contract" to the fisheries agencies and tribes. NCAC fully supports the option put forward by American Rivers in their scoping comments, so we will not repeat those here.

6) The costs and benefits to the region for FELCC shifting should be reevaluated.

7) BPA should have the right to run its own conservation programs for IOU customers served by the Exchange. It is in BPA's financial interest to conserve cost-effective Exchange energy, but because the benefits of the Exchange are simply passed through to the retail IOU customers, much conservation is not being done for this customer class.

Respectfully submitted,

Steven D. Weiss

Steven Weiss, for the
Northwest Conservation Act Coalition

cc:Don Wolfe

Mr. DEFAZIO. Thank you. I want to thank all the members of the panel for good testimony.

Just in general response to a point raised by a number of members of this panel and previous panels, this Committee will hold a hearing in Washington, DC on the government corporation proposals. We expect to see some degree of detail beyond the seven-page outline, which is all I have seen thus far, from the Administration in the near future, and also on the issue of repayment reform. We will be holding a hearing on both those issues perhaps in October. So we will air that and invite people to give their views. We have basically got to wait for more details from the Administration.

There are some interesting points to get into here. Mr. Lorenzini, you have raised some questions about the residential exchange and they were rebutted by two of our subsequent witnesses. I would just like to have a little more dialogue. I am not trying to foster disagreements here, but I think you have both got a point and I would just like to explore that a little bit more, because it was also raised in earlier testimony about the idea of perhaps changing—and I think you raised it in yours—the character of the exchange agreements by a buyout or setting a price certain or some kind of lock. So is there ground for some agreement here? Could that address the inefficiency concerns that you have raised? Is there some ground for agreement on a way to restructure this? I would like all three of you who raised that point to address it.

Mr. LORENZINI. I would hope so. I do not see that there is anything in the contractual suggestion that we have made that ought to cause a problem.

Mr. DEFAZIO. You have made a very specific proposal to BPA for a longer term contractual——

Mr. LORENZINI. We have not done anything more than make the proposal in our testimony here today.

Mr. DEFAZIO. Oh, okay.

Mr. LORENZINI. But we would be willing to pursue that concept.

Clearly Mr. Myers is correct, none of us have an incentive to be inefficient. We are all facing a competitive environment. No matter what we say about the way we would like the world out there to be, it is competitive and competition is measured by the fact that customers have choices to make. Customers on the BPA system are looking at those kinds of choices and BPA is going to face the consequence of that if they are not competitive. And so we all have an incentive to be efficient.

It just seems to me that if we take a step to become efficient and it saves us a certain amount, saves our customers a certain amount, and then that is offset by the effect of the residential exchange, that takes away some of the value of the efforts that we have made to become more efficient. The same is true for BPA. To the extent they become more efficient, if the consequence to the BPA is to remove some of the value of that efficiency gain from them, then that is a disincentive. I do not know how else you would define a disincentive. And that is the way the residential exchange works today.

And so our proposal is to try to capture and lock in the current value of the residential exchange, and then create a context in which, to the extent we can become more efficient, we are able to

capture those full benefits for our customers, and the same would be true for BPA.

Mr. DEFAZIO. Mr. Myers, could you comment on that and then I will ask Mr. Reiten also afterwards.

Mr. MYERS. I will be quite brief. I believe that, as has been expressed by a number of the panelists this morning, we are not dealing with a bunch of independent actions here. We are dealing with really an aggregate number of actions that involve things like tiered rates, and you know, everything is inter-related. And I think, as Mr. Drummond expressed earlier today, the question of how you handle the residential exchange with a tiered-rate structure is one that has yet to be examined. Yet it is certainly conceivable that within that context a solution to part of the problem that Mr. Lorenzini describes could exist. I mean, it may well be that tiered rates enter into that discussion as well.

Mr. DEFAZIO. Are you familiar with their proposal or just——

Mr. MYERS. Well I am not familiar with their specific proposal. We have other utilities in the region who have bought themselves out of the residential exchange and gotten some kind of agreement. It is not clear that that is really the best action for anyone. It always involves some sort of forecast of what the future holds.

Mr. DEFAZIO. Looking around the round world down the road.

Mr. MYERS. And as an older fellow in this business, the only thing I really know for sure about forecasting the future is I think I am going to be wrong.

Mr. DEFAZIO. Okay. Mr. Reiten.

Mr. REITEN. Well I would agree with the sort of fundamental structural view of the exchange that Mr. Lorenzini described. I think I also agree, which was alluded to both by Mr. Myers and Mr. Lorenzini, that in practice we do not consider addressing our costs in any way to gain us an advantage as a result of that exchange being there. We have much greater forces on us to keep our costs down. And if that is a negative in the calculation of the exchange, so be it. We think in practice it is not expressing behavioral changes in us in any way as a result of the way it is designed. But fundamentally it does, if you think about it, set up a disadvantage for both Bonneville and for the people who are using the exchange, such as investor-owned utilities, if they move their costs one way or the other. And we really probably ought to address something that is structurally not right that is not being used in practice.

Mr. DEFAZIO. Okay.

Mr. PILON. Mr. DeFazio, could I make a comment?

Mr. DEFAZIO. Sure.

Mr. PILON. The residential exchange may have been very appropriate at the time the Act was passed, the rate differential between private utilities and public utilities in the early 1980s was different than it is now.

I am not sure the residential exchange at all is appropriate any more. Now I realize it is in the Act and all that sort of thing, but there are about $200 million a year that my customers are paying to the investor-owned utilities in the region to buy down their rate. Our recent rate increase puts our residential rate very nearly equal to the residential customers of Mr. Reiten's company. Their an-

nounced rate increase will put our rates about 5.8 percent below their residential rates, at a time when my customers are paying money—that is what it is, it is not an exchange of power, we are paying money—to allow them a 30 percent discount in the residential rate. I think the time of equity is gone.

Mr. DEFAZIO. Okay, thank you.

Mr. REITEN. I cannot help but respond to that——

Mr. DEFAZIO. Go right ahead, I like that.

Mr. REITEN [continuing]. By saying the time of equity was here in 1980 when they considered all the ratepayers in the region beneficiaries of a regional hydroelectric system, both public and private alike, that was the equity that should have been made and was, and it still holds true today. And that equity should still be there for the members of the region. They are federally funded projects and should not be used exclusively for the rights of one group of customers versus other groups of customers in a region that received that overall attention on a federal basis. So we have a friendly disagreement with that.

Mr. DEFAZIO. Well let me draw one other twist to this, since the major concern that is being addressed by a lot of the customers here is the future—whether or not BPA's rates are going to remain competitive, particularly because of some of the extraordinary burdens which are placed on them that are not placed on IOUs or other generators or utilities. Look at reconstructing this so that, you know, you can share in the upside and the downside? Is that a possibility?

Mr. LORENZINI. Well Congressman, it seems to me that that is basically the idea that we have proposed. To the extent that we would lock in the current value of the residential exchange in some kind of contractual relationship, we would share in the upside or the downside. If we are not as effective in achieving efficiencies as BPA is, we would lose value that we would not lose if we did not make that change. And so it seems to me that that is the whole purpose of what we are proposing. And I would also add my support to the comments that Mr. Reiten made concerning the——

Mr. DEFAZIO. Mr. Myers cannot resist another——

Mr. MYERS. I just want to be sure we understand the way the residential exchange works. It does involve both an upside and a downside risk because there is an accounting that goes on. Should the inverse occur, should our rates get lower than Bonneville's in this residential exchange, an account makes it go the other way. So there is a sharing. I think you need to perhaps talk to the Bonneville people who administer this, but it would work both ways.

Mr. DRUMMOND. I cannot resist. Mr. Myers is right, there is a sharing. The difference is that an account accrues and there is not an actual payment that goes from the investor-owned utility back to Bonneville. It is just an account that is maintained that is extinguished if the——

Mr. DEFAZIO. If it reverses again.

Mr. DRUMMOND. That is right.

Mr. DEFAZIO. This is good. I learn something at all these hearings. I was not familiar with that.

Mr. DRUMMOND. And frankly, you know, that is something that we would certainly support being changed. If they want to provide

us with a cash payment when their rates get above Bonneville's, we are willing to cash the check.

Mr. DEFAZIO. I am sure.

Mr. Drummond, you talked about someone going out and looking at a 30 mill project. One of the problems I have with all this is, sure the future of BPA is fraught with uncertainties; on the other hand, they have some pretty substantial stuff underlying the reasonableness of their rates. You are talking about gas-fired generation. This 30 mill project, does this bring a long-term contract for provision of gas at some fixed or predicable escalated price, or is it subject to future market variations?

Mr. DRUMMOND. I cannot tell you the specifics of the contract, but what I can tell you is that I can go to Morgan Stanley today and buy a long-term hedge in natural gas. I can buy hedges from any number of sources, large New York houses that will give me protection against the increase in the price of natural gas. I can buy natural gas in the ground and protect myself against increases.

Mr. DEFAZIO. Right, but you also have the Clean Air Act and the potential for CO_2 regulation or taxation.

Mr. DRUMMOND. Oh, sure, I remember well the Fuel Use Act that prohibited exactly the sort of development that we are talking about now. So certainly it can turn around. I think the point is that remaining a Bonneville full-requirements customer is not a risk-free strategy. It carries with it significant risks. And what people are doing is trying to balance the risks that they see in remaining a full-requirements customer or even a partial-requirements customer, versus the risk of new resource development.

Mr. DEFAZIO. Okay. Mr. LaRocco, my time has expired.

Mr. LAROCCO. Thank you, Mr. Chairman, you asked the question I wanted to on that 30 mills thing. It caught my attention as soon as you mentioned it. What kind of energy—that was gas?

Mr. DRUMMOND. Yes, sir.

Mr. LAROCCO. Mr. Lorenzini, you had mentioned in point seven of your testimony that, "We believe the investments Bonneville is making in fish and wildlife programs could be targeted more effectively to meet statutory requirements." Could you give me some ideas on how that might work? This goes to yesterday's hearing, but we did not have your involvement yesterday.

Mr. LORENZINI. Well, our view consistently has been that in establishing the fish and wildlife requirements, there is a need to begin by establishing and setting the overall objectives and the goals for fishery escapement that we are trying to achieve, and then measuring the programs against those goals. And that process has not been followed. And so our concern is that if it were followed, we believe the priorities would be different, and we believe that many of the programs that are being currently funded may not make the priority list. And I would be happy to supplement that if you would like and submit some additional comments.

[EDITOR'S NOTE.—This information may be found in the Appendix.]

Mr. LAROCCO. Are you talking about like poaching and the squawfish—those types of programs that they are involved in—because it is pretty widespread, or the spill program?

Mr. LORENZINI. No, we might be talking about specific programs and specific areas that are not really aimed at protecting fish that have been declared to be endangered, but have other purposes. And as I say, we can provide some specifics on that.

Mr. LAROCCO. Okay, that might be helpful.

Mr. Reiten, I have not read every word of everybody's testimony because it was so complete and the constraints of time, but you touched on something that I am interested in. You said on page 6 of your testimony—and I realize this is couched in sort of a question—"[I]t may also be advantageous to the region to allow BPA to swap old U.S. Treasury debt with private financing." It is part of the discussion that is going on with regard to reinventing government and the national performance review. I believe Senator Hatfield got the ball rolling here, but as an old stockbroker and somebody who has dealt with municipal markets and so forth, I am kind of interested in this. I think the test has to be that there is no increase to the ratepayers, you know, for this to work. There is a tremendous value to the country and the region with low interest rates and some price stability, low inflation and so forth. I do not know if anybody else mentioned it, but jump in if you want to. But Mr. Reiten, you caught my attention.

Mr. REITEN. You just commented on the point—interest rates are such today that if you are going to place any long-term financing, this is the time to do it.

Mr. LAROCCO. Yes.

Mr. REITEN. If the federal debt of Bonneville is a problem for the Clinton Administration or the Congress, there will never be a better time to replace Treasury debt with the market rates that are in place now. The competitive impact on Bonneville of the change between the current repayment program and what that might be, I am not aware of what the numbers are there, but to the degree that that is either desired by Bonneville's management and by Congress or the U.S. Department of Energy, there most likely will never be a better time to do that than today.

Mr. LAROCCO. Yes, if we are going to treat it like a business—you would probably do it, you probably have.

Mr. REITEN. We are doing it.

Mr. LAROCCO. Idaho Power is doing it. I looked at Boise Cascade's 10–Q the other day. They are saving $5 million a quarter in lower interest rates, and the refinancings that are going on are tremendous in the savings.

The amount of this, anybody, is what, about $3.6 billion?

Mr. DEFAZIO. Well it depends upon whether you discount to present value and whether you are looking at the new debt/old debt total.

Mr. REITEN. Six to eight is the total amount and the amount that that would be on a present value basis is——

Mr. LAROCCO. Well I think that this task force ought to start looking into that, Mr. Chairman, too. I do not know when we can do it, but I have a particular interest in it. I have even talked to my staff, not the committee staff, about looking into it, because we are going to be engaged in more spending cuts and as the NPR stuff comes before the Congress and we look at ways that we can do this through the Executive Branch rather than through Con-

gressional initiatives, this may be something. So you caught my attention. Anybody else have a comment on that?

Mr. PILON. Congressman LaRocco, our group may favor a one-time access by Bonneville to the private debt market to buy out the old debt—one-time access.

Mr. LAROCCO. One time.

Mr. PILON. One time access. We do not believe Bonneville should have an ongoing access. We are concerned about who they check with before they go to the market. We also do not believe that the debt cap ought to be raised. We believe that Bonneville needs to be more aggressive in funding its needs through third-party financing. There are systems in place to do that if Bonneville would make wider use of them. I am thinking primarily of the billing credits. Of course, if we have tiered rates, I am not sure billing credits makes any sense.

Mr. DEFAZIO. Just if I could add, my position has always been that if we can establish either a rate neutral purchase, which gives us future certainty, or refinancing of the debt and/or perhaps ideally some slight advantage, I am interested. I am not willing to accept some major new cost, and I think I heard Mr. Reiten tell us we were at the bottom of the market on interest rates and there was never a better time, so we are all going to go out and lock in now, but I know what you are saying. It does look like a good time and I am seriously interested. In fact, coincidentally I ran into Leon Panetta, head of the Office of Management & Budget, and we had a significant discussion of this in the San Francisco airport last Sunday night at ten o'clock, for whatever that is worth. And maybe I will see him on the plane again tomorrow night and we can continue the discussion. But this is a very serious proposal, more so than in the past. It is not being put forward in a punitive manner by this Administration, as past Administrations have put it forward, and there is a potential slight advantage to the Federal Government in doing this, but not so much. You know, if we get rate neutrality, it will not be a big windfall for them, but it will still be something they can count against their obligations.

Mr. LAROCCO. And it is my understanding that there is going to be a hearing on this subject in late October or early November.

Mr. DEFAZIO. Yes, we will do a hearing in Washington on this as soon as they have crunched the numbers at OMB and they can give us a proposal, and I think that is going to happen.

Mr. LAROCCO. If I may yield back to me, Mr. Chairman.

Mr. DEFAZIO. Yes.

Mr. LAROCCO. Mr. Golden, you brought up a point that I had asked Administrator Hardy about, how the public is going to be involved in reinventing BPA and the Competitiveness Project. And you had expressed some concerns that you were not on the mailing list. And quite frankly, I do not know if I was. That concerns me. I think all the public should be involved in this. I do not see Mr. Hardy here right now or his staff—oh, no, Steve is here. I am sure you heard that and would you like to comment further on that?

Mr. GOLDEN. I do not need to be on another BPA mailing list; I am on thousands of BPA mailing lists.

Mr. LAROCCO. Thousands?

Mr. GOLDEN. At this point in the competitiveness process, from what we can glean from the outside, it appears as though many of the fundamental decisions are being made in the course of developing a marketing plan. While it is true that there is some participation in the function-by-function review, there is no participation in the marketing plan. And actually frankly, I do not think we are alone; I think the customers are outside that door too. And there is always a question about having gone through that exercise internally and come out with something that they say well this is just a draft, how dry is the ink on that draft, and in our experience, it gets dry pretty quick before anybody gets a handle on it. But I guess I am not suggesting that there are fundamental decisions being made illegally behind closed doors.

Mr. LAROCCO. Right.

Mr. GOLDEN. What I am suggesting is that all the rhetoric that is emerging from BPA right now suggests that what they want to focus on more is their customers, and the ultimate question in my mind is who is in charge? Are the customers? Are we going back to the days or the proposals that instead of having a Power Planning Council that is chosen by the states, that is empowered to make fundamental policy and planning decisions, that the customers do that. That is my objection. And you know, frankly, BPA can and has been very successful at creating a lot of public process that results in very little public access to real decision-making. More process is not the answer.

Mr. LAROCCO. Okay, well I appreciate that. That is why I think it is a propitious time to hold these hearings and for the establishment of the task force. Things are changing. This is totally different than reading in the *Wall Street Journal* that IBM is laying off 100,000 and they make these determinations within their executive committee. I mean this is a federal agency and it involves our whole region and shapes our lives and our resources. So it is a different entity, but it is incredibly important. They have got to respond to the marketplace too and the demands by the public to reinvent themselves, as we are doing in Congress, or trying to.

I yield back to you, Mr. Chairman, thank you.

Mr. DEFAZIO. Thank you.

Mr. Pilon, you raised the issue of the DSIs and that you felt the variable rate should be eliminated. I assume moving them to some cost-of-service-based rate or—I do not know exactly what rate you would set for them, but you are saying you would move away from the variable rate?

Mr. PILON. There is a tariff rate in Bonneville's rates right now; it is the industrial priority rate, the IP rate. And I am just suggesting that that is the rate they move back to, like the other non-aluminum DSIs.

Mr. DEFAZIO. Mr. Myers, if I could ask, you made a strong statement and I do know if it extended to DSIs, but about both the unbundled services and other rates by BPA being set at cost-of-service or market-based. Do you think that should apply in this case?

Mr. MYERS. Well in my complete remarks, I also touch on this. Yes, we believe that it ought to be cost-of-service-based. I think where we perhaps have not done enough is to really examine what

value could exist with the Direct Service Industry load and the flexibility that comes with it. There is no question that when it was first put into place, when we first got the DSIs here, they gave us a remarkable load steady across the entire year, which helped us really spread fixed cost over a large number of kilowatt hours. I believe there are still more benefits to be extracted from the Direct Service Industry load by making some changes in the way they operate. And for instance, I know at least one DSI who has more flexibility than most of the rest in terms of their ability to endure longer interruptions. And I would like to see us really creatively get together and work on trying to capture more benefits, and then assign the appropriate cost. If we give them credit for what they bring to this, we might end up being better able to sustain this industry, and I have to tell you that certainly even though we do not serve the Direct Service Industry loads that are located within our service territory, all of the employees who work in these companies are customers of mine and we have a very real interest in them continuing to have jobs and maintaining the viability of those communities.

So I guess what I am urging is that we not just accept all the facts as they are today and asking either it ought to be or it ought not to be. I think what we need to do is get a lot more creative in terms of looking at this and see if there is not a better way to approach this pricing and the way we actually serve this load so we could all benefit in the region.

Mr. DEFAZIO. Okay. I think the panel members probably heard my earlier question, I was talking about the concern about least-cost planning. Now I realize that the private utilities are subjected to their PUCs and the rules of the PUCs, so maybe I should first direct this to the publics, and to Mr. Golden. Do you think that preference customers should be somehow individually held accountable to either individual or to a contributory portion of the process developed by the Power Council, or do you think everything is just fine the way it is?

Mr. GOLDEN. That is too easy for me. Go ahead, Fergus.

Mr. DEFAZIO. Mr. Drummond, do you want to address that?

Mr. DRUMMOND. Yes, indeed. First of all, it seems to me that if the Power Council's plan is truly a least-cost plan and it does contain least-cost resources, it is still going to be a valid and valuable road map for the region as well as individually. I am not convinced that individual utility resource development is going to be that much different, in large part because each and every time a public utility or even a private utility tries to develop a resource, the first thing they face, be it from their own customers, from public hearings that they hold, or from any energy facility siting committee, is the Council's plan. Be it at FERC, if it is a hydroelectric project, wherever the regulatory body sits, the first thing they have to answer to is where does your project fit in the Council's plan. So I am not convinced necessarily that regional planning is by any means harmed or even wounded with the diverse nature of resource development that we are headed toward.

I would also suggest, you know, as per discussions of public involvement, the utilities that I represent are governed by elected boards. They face their public each time they face election, just as

you do. So they know very well what the consequences of—I will not say poor, but decisions that do not work out as well. There are a number of managers, certainly a large number of commissioners and directors, who are no longer directly involved in public power as a consequence of what happened with the supply system in the late 1970s and the early 1980s. So those consequences are very direct and they are very clear, and the signals are very direct.

Mr. DEFAZIO. If I could just say, I heard testimony in Portland on their perception that the BPA is becoming uncompetitive, noncompetitive. The question is, when the road curves over the horizon, what is really there. If you look at the levelized cost of some of the acquisitions that some of the public utilities have gotten into, you know, except under a worst-case scenario, they would not seem to be paying off, although maybe they are getting something else out of this.

Mr. DRUMMOND. But look at the Mid-Columbia utilities; you heard from Grant yesterday. Grant Public Utility District in central Washington developed a resource at a time when the cost of power from that generating project was twice what Bonneville's rate is today. And now their rates are considerably lower than virtually any other Bonneville customer. So there are risks to be sure, but if I as a utility manager or as a public utility run a bidding process and I come in with developers and I look at the various risks, there is no way that you can argue that remaining a full-requirements customer is a risk-free strategy.

Mr. DEFAZIO. No, I am not trying to say that, but we have an imperfect mechanism, you know. From my perspective, the private utilities are probably more accountable than the public utilities, in a way. [Laughter.]

No, in a way, they are.

Mr. DRUMMOND. I disagree with that statement completely. They face the voters each and every time they stand election and that is accountability, as you well know.

Mr. DEFAZIO. If I can just finish my statement, Mr. Drummond. The private utilities have to go before a PUC, which is equipped with extraordinary resources to comb through their proposals and to impose mandates on them. It is an imperfect mechanism to say that the public is constantly monitoring the actions of the public utilities within a margin. If you get to an extraordinary point like when I led the candlelight ratepayers march to the Springfield Utility Board a decade or so ago you get past a certain point and you can organize the public. For the most part, a 15 percent rate increase or a decision to purchase a small percentage of the WPPSS projects is done with no public scrutiny. There was one person who came before the Springfield Utility Board, that perfect publicly elected body, to protest the purchase of the WPPSS. He turned out to be really right, but most everyone else did not care. Power was cheap.

So I am just saying I think we need another level of certainty, which comes from the Public Power Council or somewhere else, that we are making these best decisions because an awful lot of those decisions are made at Board meetings when there is no one there, and people are not going to come. And ten years later, when they find out, God, they have really stuck us with something here,

it is too late to undo. We cannot undo WPPSS. If we could have stopped it beforehand, we would not even be in this room today because that power would be so cheap from BPA, we would not know what to do.

Mr. DRUMMOND. But look at Mr. Golden and remember that he was a part of Seattle City Light's least-cost planning process, a very active participant as I remember. You know, I would like to think that indeed we have learned something from our experience with the supply system and that the days of being able to sign on to a major or even a minor generating resource without significant public input, be it through the Energy Facility Siting Committee, be it through the FERC licensing process, or be it through the individual utility boards, is simply not going to happen.

Mr. DEFAZIO. Mr. Golden.

Mr. GOLDEN. I just note that it is no coincidence that Seattle City Light is one of a small handful of public utilities in the region that is on a trajectory on their conservation programs that might meet the Council's plan.

I think even under the existing system with Bonneville acquiring resources in a centralized fashion, it is clear that we are having a hard time holding the region accountable to the goals of the Power Planning Act, and it is not a matter of the Council micro-managing resource acquisitions. I mean the gap between resource acquisitions on the ground right now and what is in the Council's plan is embarrassingly large. This is not a little bit of variation on the margin. The Council's plan is not being used as a guide for Bonneville's resource acquisitions, let alone the resource acquisitions of smaller utilities.

Yes, I think in some circumstances it is regarded as a hoop that people need to jump through, but I think that Tenaska was able to jump through that hoop with remarkable alacrity. And that is under a centralized system, and I think it gets worse under decentralized resource acquisition. I firmly believe that there must be a mechanism under this system and even more so under a decentralized system, that holds anybody who is going to acquire resources and anybody who is going to enjoy the benefits of the regional system to the prescriptions of the regional program. Do I think that needs to be micro-managed? No. Do I think the Council is inclined to micro-manage or wants to micro-manage resource decisions? Absolutely not. They have demonstrated that abundantly, and they should not.

But I do not see how any fair reading of what is going on right now in regional resource development can suggest that what we are ending up with is an energy future out of the acquisition processes that are now in place, or that look much like where we told ourselves we were going in the regional plan. We are being swamped by gas.

Mr. DEFAZIO. Mr. Drummond wants a quick response.

Mr. DRUMMOND. My understanding is Bonneville is on the path to acquire the resources, the 660 megawatts of conservation that was included in the Council's plan. Second, there was a considerable amount of gas included in the Council's plan. Non-firm was a strategy that was well discussed during the development of the

Council's plan, and I view Tenaska as part of that process. I mean I will not say Tenaska itself, but certainly the acquisition of——

Mr. DEFAZIO. We aired this at my Portland hearing and the concern I expressed to the Council was a lack of assertiveness on their part where they rather passively said, oh, you mean the price of the gas is secret and we cannot know it? Oh, okay. You know, that was not the kind of public scrutiny I want to see.

Mr. DRUMMOND. We have no position on Tenaska and that is not——

Mr. DEFAZIO. I mean I am not going to get into it. I do not have the capability of evaluating it, but I think that was a breakdown of the public oversight process in that case. I do not know how any public body could have responsibly made that decision, not knowing what the adjusters were, what the contingencies were and all that. I mean it is very difficult. It may make tremendously perfect sense. BPA may have made the best decision, but I would just like to have that second level of scrutiny. Mr. Reiten.

Mr. REITEN. There is a potential problem and that is that in the investor-owned utilities who go through least-cost planning process, all the factors are considered—demand-side management programs, gas prices, renewables and the least-cost path, including some allowances for the higher cost resources that may have better environmental benefits than some others—all are melded together through an open process, and we arrive at a point.

In terms of resource acquisition for the public, if the public, particularly the customers of Bonneville, go out and acquire their own resources of let us say 30 mills, and the preferential rate is 27 mills today, but Bonneville, as a result of public power influence, federal influence, other influences, goes forth with even larger mitigation programs for fish on the river and we go from $300 million to $350 million or $400 million in cost, the resource that goes to the Bonneville customer by an independent power producer does not carry the cost of the social programs, which I would agree needs to be done. Bonneville's revenues have to reflect those because they in fact are doing them, but they are losing businesses to resources that are coming in that are not priced with any fish mitigation or demand-side management program or so on with them. And this is the path that is being started today, principally on the public side. So there is a difference between the least-cost planning process in investor-owned utilities and what we are seeing happening on the public side in this particular area. And you could have larger demand-side management programs, fish costs, on fewer kilowatt hours at Bonneville as a result of these new resources coming in that are not fairly reflecting the prices of those public-policy-driven requests and requirements for Bonneville.

Mr. DEFAZIO. Yes, I think that is an excellent concern. Do you want to comment briefly on that, supplement that?

Mr. GOLDEN. Yes, once again on the conservation——

Mr. DEFAZIO. Well we had a whole hearing in Portland on conservation, we do not need to——

Mr. GOLDEN. I would actually like to address though the 30 mill gas project, because I think this gets to the heart of the issue of whether people can be held accountable to least-cost planning goals in a market that says, 30 mill gas, why do anything else. There are

a whole wrath of environmental reasons why one would choose not to do that, and I think they are well known to everyone and I will leave them behind for the moment.

Just on economic grounds, gas price risk, you may be able to buy a hedge against it. The hedge presumably costs something. And I think the experience so far is that no one can hold somebody to a low gas price contract, no matter how long it is for, if there is a huge price run up, and there is still enormous risk there.

CO_2 risk, Bonneville tried to ensure itself against CO_2 risk in purchasing Tenaska, and was unable to do so. Where did that risk go? It did not go away because Bonneville could not acquire insurance. The insurance companies did not want it. Consumers do not want it, but consumers end up with it. We are ensuring a fossil fuel industry against that risk now, if Tenaska goes forward.

And finally, I am not sure exactly how this works, but in an unbundled world, it seems to me that a lot of the costs that now get loaded into Bonneville's PF rate are now off in their own bundle somewhere, and the costs that you are avoiding as a Bonneville customer by developing your own resource, the energy cost, is going to be lower. So in other words, I think it is quite possible that a utility could go out there and maybe find an engine a mill or two cheaper than Bonneville can build an engine, but then it is going to have to go out and buy wheels and a transmission and a windshield and a steering wheel and maybe a radio. And by the time it gets through assembling this car by itself, I really question whether it is going to look a lot cheaper than if they had just bought the car from Bonneville in the first place.

I think those who think there is a vast 30 mill resource out there are kidding themselves and are going to find out.

Mr. DEFAZIO. But I think you did not really address Mr. Reiten's point. For that individual utility, they are in part, as much as they acquire another resource, avoiding the public social costs, which we have decided upon in terms of Columbia River Basin salmon, fish and wildlife, and others. And that is something that I really think we have got to wrestle with there.

Mr. GOLDEN. But they are not avoiding the social cost of carbon risk; they are passing it on to their customers.

Mr. DEFAZIO. That may be, but that is not apparent in making the decision at the outset, or even in the short-term, until something happens under the Clean Air Act or in Congress. You know, they may skate for quite a while. There was other testimony on this whole idea of serving a narrowing base—particularly Mr. Pilon's people, who are full-requirements customers and want to stay full requirements customers—picking up even more and more and more proportionately of the social burden, while other people go another route. Do you have any thoughts on that, Mr. Pilon? I mean I think that is a particular problem for your organization.

Mr. PILON. Well I think your perspective, Mr. Chairman, is right on. There will be utilities in our group that will be ill-positioned and unable to take advantage of unbundled services or developing their own resources and we will be left on Bonneville to pick up those costs—you are absolutely correct.

Mr. DEFAZIO. Okay, unless anybody else has something they really want to say—Mr. Drummond.

Mr. DRUMMOND. One last thing, and it is an issue that has not come up here in any of the panels that I have heard so far, and that is the issue of retail wheeling.

Mr. DEFAZIO. Is what?

Mr. DRUMMOND. Retail wheeling.

Mr. DEFAZIO. Well I referred to it in my opening statement. I alluded to it.

Mr. DRUMMOND. I would suggest that whether or not you believe retail wheeling is appropriate, whether or not it comes, it may in fact force a lot of these changes even more quickly than we envisioned, just because customers of the utilities will demand the sorts of changes——

Mr. DEFAZIO. Right. I am not sure what Congress did in the Energy Act as pertains to retail wheeling. I think that will be determined by FERC or further guidance from Congress. But I was alluding to that when I made the analogy to the phone system. You know, the MCIs, the Sprints and that, very competitive, brought down costs for a lot of folks. You get to another point, the individual consumers. You may be adding essentially built-in costs with more diversity and bureaucracy and that. Retail wheeling, I have some tremendous skepticism about getting up in the morning and reading my computer printout and pushing the button for my provider for the day, you know, or whatever time of day I am given the option. I am not sure that Congress has opened that door yet. In my opinion, I do not think it was opened by that Act, but there may be other opinions.

I really want to thank you for the amount of time and the good testimony. It was very helpful to me and we will have more opportunities to talk.

We are now going to take a brief break for lunch so that we will not keep the next panel unduly, so 20 minutes from whatever your watch says, from now, we will convene the final panel.

[Whereupon, at 12:55 p.m., the task force recessed, to reconvene at 1:15 p.m., the same day.]

AFTERNOON SESSION

Mr. DEFAZIO. Will the persons on the next panel please come forward. You do not have much of an audience, but you are being recorded for posterity, so we will be fine. Let us get started, we will start just in the order on the list here. So Mr. Carr will go first.

PANEL CONSISTING OF JOHN D. CARR, EXECUTIVE DIRECTOR, DIRECT SERVICE INDUSTRIES, INC.; JEFF SHIELDS, GENERAL MANAGER, EMERALD PEOPLE'S UTILITY DISTRICT; DAVID E. PIPER, EXECUTIVE VICE PRESIDENT AND GENERAL MANAGER, PACIFIC NORTHWEST GENERATING COOPERATIVE (PNGC); KERMIT W. SCARBOROUGH, CHAIRMAN, CANBY UTILITY BOARD; DONALD R. CLAYHOLD, MANAGER, BENTON COUNTY PUBLIC UTILITY DISTRICT, WASHINGTON, ON BEHALF OF NORTHWEST IRRIGATION UTILITIES (NIU); AND WILLIAM P. KITTREDGE, DIRECTOR, SPRINGFIELD UTILITY BOARD

STATEMENT OF JOHN D. CARR

Mr. CARR. Good afternoon, Chairman. I am John Carr, with the Direct Service Industries, the customers that purchase approximately 30 percent of Bonneville's power. I will even stand in today for the shareholders of 30 percent of the power since we are end users. I point out that approximately 60 percent of Bonneville's total sales ultimately go to large industry and some agriculture.

I will not spend much time on the need for the changes in the competitiveness side, I think Randy and other people did a real good job of laying that out. I will try to put a different twist on it though quickly.

For Bonneville to be competitive, it must participate in a competitive market. And it is as important that the market is competitive as it is that Bonneville makes efficiency changes. I find when I look in my crystal ball that there are basically four things that need to happen to have a competitive market.

First, tiered rates need to be established. I strongly support the concept of tiered rates, but I think we should not use them to try to do everything. We should try to keep their means simple.

What I would recommend is that we basically vintage the rates, we vintage the existing costs into tier 1. When I say existing costs, I mean fish and wildlife, I mean exchange costs, and all the other costs that go with the hydro, supply system costs, all those go into tier 1. Tier 2 then becomes the costs of new resources, whether it be conservation programs or generation resources. And in the best of all those worlds, those would be sold on a bilateral basis. If Bonneville could actually contribute a service for a new resource or a conservation program that was better than the alternative in the marketplace, a utility could purchase that.

The second thing that needs to happen is, at least in the region, common carrier status on the Bonneville transmission system. We need to have access for DSIs and other customers, so that if they want to bring in their own resource, they have access to the transmission in an unbundled way, to get that to their load in a cost-effective way and in a non-prohibitive way.

Third, Bonneville needs to unbundle its resource integration services and provide those to any customer that wants to bring in their own resource. And the important thing here to make the market competitive, is Bonneville should not be allowed to offer those services to a customer for integrating a resource that a customer wants to bring in, at a higher price than they would if they were trying to peddle their own resource. That has to be the principle. In some ways, an analogy is that the resource side or conservation program side of Bonneville, for new resources, would become almost a wholly owned subsidiary that had to compete on an armslength basis or offer these resource integration wheeling services on a fair and equitable basis with any other customer out there. That way, to go back to an earlier example I think some of the witnesses brought up, I do not want to see a 35 mill resource brought in by Bonneville to sell to customers for 32 mills—when a customer could have got a resource for 30 mills—just because Bonneville uses its wheeling power or its resource integration services in a way that basically got in the way of that utility bringing aboard for industry the 32 mill resource. The reason is obvious. If you get a bunch of 35 mill resources brought on instead of 30 mill resources, the region is going to face higher costs in the long run.

The fourth thing that needs to happen is more efficiency in terms of Bonneville. Bonneville is moving to become more efficient, market-driven, and I think one of the things that needs to occur is probably something along the lines of the government corporation status. We will support that; maybe the debt swap we have been talking about. I know you are going to have another hearing so I will not spend much time on that today, but given the principles the publics have laid out, we support both of those efforts as a way to reduce risk on Bonneville's rates, and in the long run, I think makes Bonneville more efficient.

Now let me make a comment about the Power Council. I think the Power Counsel has an important role to play over the next several years as we go through these fundamental changes. And it is not a managing role—I think that is the word that was used earlier. It is a leadership role. It is looking toward the future and helping us get through this transition so that we get to a free market or much freer market without a lot of additional costs being spent.

I would also like to take this opportunity to really give a lot of credit to Randy Hardy and his chief administrators. They have taken the bull by the horns here. They are moving forward; to be frank, they are not moving anywhere as fast as I think you would see a private industry move, but they are making significant moves. They are opening the door to customers and others, and I think that is very positive.

In closing, I would like to make a couple of recommendations for the task force. I realize I am getting a little bit ahead of the next hearing, but one thing is that Randy Hardy and the folks at Bonneville are going to face a lot of struggles as they go through this Competitiveness Project. I think we are just touching the tip of the iceberg. There are going to be many more issues on the table over the next couple of years and Randy is going to need a lot of support. And I think strong support for the effort and the direction

that Bonneville is going from the delegation, will be very important. And I think this task force and you, Chairman, can take a very strong leadership role there.

The second thing is new legislation. I think new legislation in the form of a government corporation and the debt swap, just a one-time access to private debt markets for the old federal debt, makes a lot of sense, especially given the caveats that you did earlier in your comments about the debt swap. That is going to require new legislation and I am hopeful that this task force and again, you, Chairman, will take a leadership role in that, and hopefully take it through fairly quickly and in a narrow, focused way.

That concludes my comments for today.

Mr. DEFAZIO. Thank you. Mr. Shields.

[Prepared statement of Mr. Carr follows:]

TESTIMONY OF JOHN D. CARR, EXECUTIVE DIRECTOR
DIRECT SERVICE INDUSTRIES, INC.
BEFORE THE BONNEVILLE POWER ADMINISTRATION TASK FORCE
OF THE COMMITTEE OF NATURAL RESOURCES

September 25, 1993
City Council Chambers
Eugene, Oregon

Chairman DeFazio, it is a pleasure to appear before the Bonneville Power Administration Task Force. Your investigation and oversight of BPA is timely. The agency must change if it is to remain a positive force environmentally and economically in the Northwest. The Direct Service Industries look forward to working with you to ensure that this happens.

The Direct Service Industries, comprised of aluminum, titanium, magnesium and chemical producers, purchase their electrical power directly from the Bonneville Power Administration.

As you know, the DSIs have been a vital part of the Northwest economy for more than half a century. While directly bringing vital employment to the region, these industries played a key role in the development of the Northwest's main economic engine: the hydropower system. They continue to benefit this system in very valuable ways.

The DSIs use power in such a way that they help keep power prices low for all other users in the Northwest. They also help promote energy efficiency and conservation in the region. They make significant contributions to the region's fish and wildlife enhancements, both financially and scientifically.

The DSIs look forward to a bright future as partners with BPA, utilities and the four Northwest states which benefit from these operations.

BPA's recent initiatives to become competitive are driven by fundamental market forces. Following the course set by natural gas and other deregulated industries, the electric power industry on the West Coast is rapidly becoming a more open, competitive market. BPA no longer enjoys a large price advantage and a virtual monopoly on the high voltage transmission system. It must learn to operate in a more businesslike way if it is to survive as a premier provider of energy and energy services.

For any entity to become competitive, it must face competition for its products and services. Not only must BPA become more competitive, but the regional power system must become a more open, competitive market. Currently, BPA masks the price

of meeting load growth to its customers by melding the cost of new conservation programs and generation resources with the cost of the existing system. In addition, BPA can limit transmission access and resource shaping services making it very difficult for a customer to acquire its own resources to meet load growth. Both of these practices significantly hinder the functioning of a competitive market for load growth services.

Let me briefly describe my vision for a new, competitive BPA with four broad areas of change: 1) tiered rates; 2) product unbundling; 3) transmission policy; and 4) corporation status. I will then turn to the future role of the Regional Power Planning Council. Finally, I will discuss the Variable Rate paid by the DSIs.

BPA will move to a tiered rate pricing structure forming a wall between the costs associated with existing generation and conservation resources and the costs of meeting load growth. Utilities and industries facing load growth will have the options of: 1) purchasing directly from BPA at the actual, nominal cost associated with a new resource or conservation program; 2) entering a consortium and building a new resource; 3) running their own conservation programs with funding primarily from consumers directly benefitting from the program; or 4) purchasing power directly from another utility or independent power producer. The customer would only purchase from BPA if the agency was offering the most cost-effective, reliable product to meet their load growth needs. Other BPA ratepayers would not be off-setting a portion of the cost of meeting that customer's load growth.

BPA will unbundle its product and service lines. Replacing its *plain vanilla service* will be a wide array of services for BPA customers. BPA's core business line will continue to be providing power from the existing federal system at the lowest possible cost to its existing customers. Other services will include system flexibility, reserves, load shaping, and integrating new resources into utility systems. Each product will be priced at the cost of providing the service. Each customer will choose equally from the menu of unbundled products, and by their own selection, find an efficient allocation of resource cost. Unbundling is critically important as a means for aligning the costs of service with benefits and needs of each customer.

In addition, by unbundling the new resource integration services, customers will have access to these products at the same price for bringing their own new resources into the system, as BPA will face when attempting to market new, BPA financed generation resources. This will help provide a level playing field ensuring that customers are not compelled to accept a higher priced BPA resource than a utility could acquire on its own.

The Federal transmission system operated by BPA provides about 80 percent of the main-grid transmission within the Pacific Northwest. It would be wasteful to duplicate this system to encourage competition in generation. In order to allow competitive forces to keep down the cost of generation, BPA will have to change its

policies and make transmission available within the region to all of its customers on a common carrier, non-discriminatory basis. The philosophy behind the National Energy Policy Act of 1992 is a step in this direction, but open access also must be extended to the DSIs.

BPA will become a federal corporation. To become business-like, BPA must be unfettered from unnecessary federal rules. A one time change in BPA's existing debt relationship with the U.S. Treasury may also be necessary. This should be accomplished on a rate-neutral basis and provide significant long term stability in BPA's repayment practices. We will need your help, Mr. Chairman, to manage any required legislation to accomplish these objectives without revisiting the broader institutional issues that have been settled by the Regional Power Act.

As provided by the Regional Power Act, a reformed, revitalized BPA will continue to provide valuable services in the areas where it is most qualified. Those areas are also defined in the Bonneville Project Act. Foremost among them is the marketing and transmission of power from the Federal Columbia River Power System.

Congressman, some may say that by facilitating a more open and competitive power market, BPA limits its ability to acquire resources for the region as a whole -- a provision of the 1980 Act that was not contained in the 1937 law. This is false. The Regional Power Act clearly gives utilities the option of relying on BPA to meet load growth, or of acquiring their own resources. Under current market conditions, many utilities can more efficiently acquire and pay for resources directly, without BPA acting as their agent. Other utilities may wish to continue to rely on BPA, and that is their prerogative.

The Power Council, meanwhile, will continue to provide the moral and political persuasion to put conservation first. It will guide BPA in its efforts on behalf of those utilities that continue to rely on the agency to meet load growth. Most importantly, the Power Council can perform a vital leadership role in guiding the region through the transition to a decentralized, market oriented energy future. The state public utility commissions will continue to oversee the acquisitions of investor-owned utilities through integrated resource planning.

Let me close by addressing your questions about the Variable Rate. BPA adopted the Variable Rate in 1986 for the mutual benefit of its aluminum smelter customers and its utility customers. A cyclical downturn in aluminum prices had caused several Northwest aluminum plants to close. BPA, which had a 2,000 megawatt energy surplus even when the plants were operating, was required to sell this surplus power on the open market, far below BPA's costs.

BPA, the smelters and other customers designed the Variable Rate to maintain a higher level of smelter operations and recover BPA's costs on average from the smelters

by collecting high prices when aluminum markets were healthy and lower prices when aluminum markets were weak. The Variable Rate was a huge success for the smelters and the Region. Three closed smelters reopened and all the smelters provided the Region with revenues far above costs throughout the late 1980's and early 1990's.

Although the Variable Rate has not directly enhanced BPA's revenues during the past year when the Region suffered a drought while aluminum prices were low, the Variable Rate has worked as planned by being beneficial in aggregate over its 10-year life. BPA outside consultants recently concluded that the Variable Rate overall has provided very substantial net benefits for BPA's ratepayers. They have recommended that BPA extend the Variable Rate for another 10 to 15 years for the mutual benefit of the Agency and its customers.

Some changes are appropriate in the Variable Rate when it is revisited in 1996. Currently, the lowest power price under the Variable Rate is too high to keep the smelters competitive during cyclical downturns in aluminum prices. That same power price is much higher than the average price BPA can get on the open market for the power, if it cannot sell it to the smelters. Therefore, a lower rate limit with compensating changes to other elements of the Variable Rate could provide additional benefits to both the smelters and the Region.

The Variable Rate was designed by BPA's customers, and has often been held up as a textbook case of good public and economic policy. So good, in fact, that it has been adopted in various forms by the aluminum industry worldwide. We will need your help, Mr. Chairman, in providing leadership to extend the Variable Rate concept. We look forward to working with you to find other innovative solutions for the benefit of the Pacific Northwest.

Thank you for this opportunity to testify on these very important matters. I am pleased to respond to any questions you may have.

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STATEMENT OF JEFF SHIELDS

Mr. SHIELDS. I am Jeff Shields, I am general manager of Emerald People's Utility District, which surrounds Eugene, Oregon.

I represent 15,000 end users, many of whom will not be ratepayers for perhaps another 10 or 20 years, and if you can accept that, I would ask you to keep that in the back of your mind through the course of my comments. I am concerned about those future ratepayers as well as today's end users.

Many of us in the electric utility industry tend to feel that things are in a real state of disarray, that things are changing so fast, it is real hard to keep up with. I recently described that as flowing over the spillway of the twenty-first century with very little structure. I think we need some structure, we need some leadership. I think we have the institutions in place to provide that. I question is whether we are actually using those institutions for the purpose that they were intended.

Bonneville's rates are set to increase 16 percent next week, not the largest increase in BPA's history by far. They have advised us in the industry not to overreact to those increases; half of that is a one-time increase and should not be of great concern to us. So what is at the root of the uncertainty and discontent? Well I think a lot of it has to do with what we are seeing from Bonneville, what we are seeing from the leadership in the industry. Bonneville has initiated several processes which have created a flurry of activity. As you analyze what is going on with those, very little really changes. Tiered rates is a prime example. Tiered rates was discussed through the PPC and other institutions in the Northwest for 6 or 8 weeks as kind of the new thing that was going to happen. All of a sudden, it has taken a backseat to unbundling. It is hard to keep up with a lot of those things that have potentially dramatic effects on us.

WNP–1 and WPN–3 was going to be dropped out of the plan. Nothing has happened. And so with all the changes that have supposedly taken place, I think if we step back, we can take a little bit of a breath and look at what is really going on and try and put some of these things into some kind of structure that is going to guide us over that spillway so that we land on the bottom safely.

We do have to keep Bonneville competitive. We have the ability to do that. They are competitive today, and I really have not heard anybody say anything other than that. People have alluded to the fact that maybe they are not competitive, I have never heard anyone say Bonneville is not competitive, but they are certainly approaching a non-competitive position.

Bonneville has the obligation to acquire environmentally responsible resources. We need to provide leadership in the region to ensure they do that, and we have to provide some leadership to ensure that Bonneville maintains the public trust. There was a little bit of a discussion I think in the last panel about public trust and public utilities' ability to represent and get the trust of their ratepayers versus maybe the investor-owned and regulated community. And I would like to discuss that as we get into the questioning a little bit if the opportunity arises.

The brave new world of the electric utility industry—I look back to what Dwight Eisenhower proposed, which was not a federal mo-

nopoly of power, but rather public or private regulated power, freely chosen by the citizens of each area, with the Federal Government drawn in as a cooperating partner where this seems necessary or desirable. And I would like to see that at Bonneville. Not necessary but certainly desirable, something that we actually prefer to do business with, rather than somebody that we have to do business with.

It is important to maintain Bonneville's financial integrity. It is important that they continue to provide an opportunity for us to be a yardstick for the investor-owned utilities. We saw what happened prior to the formation of Bonneville, and it was not a pretty scene. People could not get power; it was not a matter of price; it was a matter that it was not available to you. And I suppose it was a matter of price—with enough money, I suppose you could have gotten it for yourself or your community. I am afraid if Bonneville simply becomes a competing enterprise with public power and private power, we may lose that yardstick. We need to make sure that whatever comes out of any future legislation or leadership, that we always recognize if we are going to have public power, if we are going to have private power, that the two have to have a yardstick.

Bonneville has to get a handle on some of its hidden costs and what drives those hidden costs. There are opportunities to acquire resources over the years, they have become the nuclear host to the Pacific Northwest and a lot of in the utility end, the buyers of the products of Bonneville, do not have an opportunity to truly analyze what those hidden costs are. The nuclear portfolio, I have some serious concerns about; the gas risks; the CO_2 risks that are not being dealt with, those future ratepayers are going to have to pay those costs and they are going to ask why was I not, why were you not, why was the region not dealing with these issues when we had the ability to do that.

There are changes in the electric utility industry in terms of technology and what is available to people. And those changes are working to the benefit of the citizens. Decentralization. People are going to have the ability over the next 10, 20, 30 years to acquire resources more suited to small industries and maybe even as far down as residential customers, giving them some choices in the resources.

We need to make sure in that process that we recognize that and that we do not bring on 240 megawatt gas-fired resources with 20-year financing obligations that we cannot get out from under. People trust that our regulatory bodies—the people assigned with oversight of these decisions—are looking out for those kind of concerns, and I am concerned that that is not taking place. We have the Tenaska resource which the Council nodded their heads to—with a secret agreement. That may have been a wonderful resource, and trust me, I hope more than anybody that it was a wonderful resource. But I certainly cannot report that to my ratepayers today.

We have the issue of what has unfortunately become referred to as the hassle factor in the Northwest, in regard to doing business with Bonneville. And it goes beyond price competitiveness. I am concerned that as resources get close to being competitive to the price of Bonneville, people may jump ship anyhow because quite frankly, it is a hassle frequently to do business with Bonneville. I

would like nothing more than to see that turn around. I think Randy is to be commended, Randy Hardy, for the function-by-function review process, Competitiveness Project. I believe all of those things are in the right direction to make Bonneville both more price competitive, but also it may lean toward doing away with the hassle factor. They are streamlining their processes, they are creating clearer and shorter lines of authority. They are empowering employees to make decisions and I hope eliminating some of the burdensome bureaucracy. And if they do that, they will end up being an institution that people desire to do business with, not simply have to do business with.

And finally the issue of their caretaker role in competitiveness. Bonneville does have the responsibility to protect the natural and built assets of the Northwest. At the heart of this role must be the reversal of the deteriorating condition of one of the Nation's most valuable assets, and that is the Columbia River Basin. I do not believe it is appropriate that any of the costs associated with those resource choices should be laid at the feet of the Nation's taxpayers. We have to shoulder those; we have to figure out how to do that.

Emerald PUD has tiered rates. Our customers understand them. They treat their choices, their energy choices, on a daily basis, recognizing that, and I would submit to you, they appreciate that.

I will not go into a lot of the details on the rate structure, we have submitted several pages in our written testimony, and I welcome an opportunity to respond to any questions you might have from that.

Unbundling of services, I think most of that has been covered pretty adequately. The one thing I would caution is in a private market—and we have seen it with the phone companies and other services—private sector providers are able to do some short-term marketing things to subsidize the cost and allow them to enter into market share. I am not sure that Bonneville is going to have that opportunity. That is something we need to keep our eyes open to, and I think that has been adequately covered in the discussion today.

With that, I think I will close on one more point, and that is the low-density discount, the irrigation discount the value of reserves—any of the issues that are truly subsidies. I think we need to get away from subsidies altogether. That is going to come at some expense to our ratepayers as well, but in the long term, I think it will make Bonneville much more competitive.

Thanks.

Mr. DEFAZIO. Thank you. Mr. Piper.

[Prepared statement of Mr. Shields follows:]

TESTIMONY PRESENTED ON BEHALF OF
EMERALD PEOPLE'S UTILITY DISTRICT

before the

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON NATURAL RESOURCES
BPA TASK FORCE

SEPTEMBER 25, 1993
EUGENE CITY COUNCIL CHAMBERS

DeFazio Hearing
Emerald PUD, page 1
September 25, 1993

INTRODUCTION

People in the electric utility industry in the Pacific Northwest will tell you things are changing so fast these days it is difficult to keep up. In preparing this testimony, I was able to reflect on the actual changes that have occurred in the past few years, and I realized that in fact, very little has actually changed.

While Bonneville's rates are set to increase by 16 percent next week Bonneville has advised its customers not to "over react" to the rate increase. Half of this increase is a "one-time increase" driven by four years of drought. So what is at the root of the uncertainty and discontent in the region?

Bonneville's competitiveness and role in the region are at the heart of the regional debate. Several processes initiated by Bonneville itself have created a flurry of activity in the offices and Board rooms of the region's utilities. Tiered rates, the Competitiveness Project, the termination of WNP-1 & 3, the acquisition of Tenaska, and the renegotiation of the power sales contracts are a few examples. All of these enjoy considerable debate in the region, but when you step back, not much has yet changed.

Clearly, change is needed in the industry, and change will occur. The question is whether we will lead the change or be led by it. We have the opportunity to change things for the better, to make Bonneville more competitive, to acquire environmentally responsible resources, and to restore the public's trust in its governmental institutions.

When we think about the brave new world of the electric utility industry and the appropriate role for Bonneville it might be helpful to heed the guidance of President Dwight D. Eisenhower who stated that the appropriate model should not be "federal monopoly of power, [but] public or private regulated power freely chosen by the citizens of each area with the federal government drawn in as a cooperating partner where this seems necessary or desirable." We think the important words here are the federal agency as a "cooperating partner" that is "necessary and desirable."

I commend congress for recognizing the magnitude of the problems facing the northwest electric utility industry. The potential impacts of the issues we are dealing with reach beyond agency and utility headquarters to touch the lives of citizens throughout the region and the nation. Thank you for providing this forum to debate these issues.

1. **Why is it important for BPA to become more "competitive"? How likely is it that BPA will become a higher cost supplier of energy to the region than other providers? Are there other reasons for BPA to undertake its competitiveness initiative? What principles should guide BPA in this effort?**

It is critical for the Pacific Northwest that Bonneville remain "competitive." It is important because unless Bonneville remains price competitive they will become irrelevant as a energy service provider, because they must react to the enormous changes in the electric utility industry, because they need to maintain their political viability and effectiveness, because they must become a partner utilities choose to do business rather than have to do business with, and because they need to maintain their key role as the caretaker of the region's incredibly valuable natural assets.

Price Competitiveness

There are enormous pressures on the cost of Bonneville's energy services. There is repayment reform/debt buy-out, endangered salmon, new resource acquisition, a poor aluminum price forecast, bureaucratic inefficiency, as well as other pressures. It is important that Bonneville preserve the financial integrity of the agency, and remain the "yardstick" of competition for investor-owned utilities. Emerald believes that this means Bonneville must provide energy services at the lowest long-term cost to society. Unfortunately, this often conflicts with short-term goals and rate impacts. However, it was the long-term interest of the people of the Northwest for which Bonneville was originally created and for which it should remain today. In order for Bonneville to fulfill this goal it must improve its operational efficiencies, its financial position and the business culture of the agency.

As well, Bonneville must get a handle on its hidden costs. By this we mean the cost of its nuclear portfolio. In 1992 Bonneville devoted more than 86 percent of its total generating budget to nuclear, yet nuclear provided less that 5 percent of Bonneville's generating output. In a recent study the WNP-2 plant was rated the worst nuclear power plant in the country, in Public Citizen's "Nuclear Lemons" 1993 study. While efforts are underway to improve the operational efficiency of WNP-2 (a dismal 54.7 percent on average from 1990-1992, 15 percent below the industry average), the facility is aging and even normal deterioration will inevitably result in increased production costs. In addition, it also appears to us that there is a disturbing lack of recognition within Bonneville and the nuclear industry of the enormity of decommissioning costs. Senior Bonneville employees readily acknowledge that existing funding levels for decommissioning both WNP-2 and Trojan are seriously deficient, and this will significantly impact Bonneville's ability to remain competitive unless this issue is dealt with directly.

As well, Bonneville is exposing itself to what could be an enormous gas price risk in the mid-to-long-term, and a potential carbon dioxide penalty by purchasing significant amounts of gas-fired resources without proper financial protection. While many utilities and state utility commissions have established an explicit value for CO_2 emissions, Bonneville has explicitly excluded any recognition of this cost in its pricing of the Tenaska project, or any fossil fuel-fired resource for that matter. We believe this artificially lowers the cost of this project, and overstates its competitiveness.

Changes In The Electric Utility Industry

Bonneville, and the Northwest Power Planning Council (the Council), have not come to grips with the reality of decentralized resource acquisition. They have not adequately accounted for utilities' efforts to become more independent and provide for their own load growth. Recently, the Council had an opportunity to assess Bonneville's resource acquisition projections against the reality of what is going on in the region. The Council held its first "Section 6(c)" hearing regarding the acquisition of the output from a 240 MW gas-fired combustion turbine facility -- Tenaska. In the Council's "needs analysis" there was little if any recognition of the efforts of several of Bonneville's customers to acquire their own resources. Rather than confront this reality, the Council elected to warn Bonneville that the next time they proposed a generation resource they could expect to undergo rigorous scrutiny.

Technology is working to the benefit of decentralized, smaller scale "dispatched generation" and "off-grid" resources. These technologies are more suited to local utility implementation and independent power producers than centralized providers like Bonneville. Advances in these technologies could leave Bonneville in the future with stranded investments.

Public Trust and Accountability

Bonneville has entered into a series of agreements in recent years which they have shielded from public scrutiny. These agreements include settlements with General Electric over issues involving the WPPSS nuclear facilities, Trojan nuclear facility obligations, and most recently a secret agreement to acquire the output of a 240 MW gas-fired facility (Tenaska). Without knowing what responsibilities Bonneville has assumed in these agreements there is no way of knowing how competitive these resources are. More important is the fact that Bonneville has seriously damaged the public's perception of its ability to keep the "public trust." Without this trust Bonneville will be seriously hampered in its ability to deal with the tough problems of today and tomorrow.

Bonneville has assumed the role of resource provider for nearly all of the public power community and, to a lesser extent, for the investor owned utility community. This has led to resource acquisition decisions that are far removed from the people who ultimately pay the bill. This isolation and distancing of the decision-makers from the people has dramatically lowered the level of accountability for these decisions. In contrast, locally elected directors of PUDs, municipal utilities, and cooperatives are directly accountable to the billpayer for their decisions. Many years ago after the decision to participate in the Trojan nuclear power plant was made by the Eugene Water and Electric Board, the consumer-owners of the utility protested. When Bonneville agreed to regionalize the responsibility for that decision there was enough distance between Bonneville and the billpayers throughout the region that the objections subsided. When Bonneville recently entered into a contract to acquire the output from the Tenaska power plant, and refused to disclose the terms and conditions of that agreement even to their utility customers, there was little recognition of the risks and the magnitude of that decision by the people responsible for paying the bill. Billpayers assume that the government regulators will exercise their oversight and ensure the public's interests are protected. Unfortunately, in the case of Tenaska, those regulators, the Northwest Power Planning Council, showed little interest in holding Bonneville accountable for that decision by demanding to see the contracts or calling for public disclosure.

The "Hassle Factor"

If recent public utility ventures into competitive bidding result in decisions to purchase projects that cost more than Bonneville's estimated long-term cost, this will be a reflection of either a conviction that Bonneville's costs will escalate more than expected, or that the cost premium is worth not having to deal with Bonneville. We have already seen many utilities take actions of independence to avoid the "hassle factor." The general public's mistrust and disillusionment with government also impacts Bonneville. People are demanding a government that works better and costs less! We applaud Bonneville's Function-By-Function review and the Competitiveness Project. These initiatives are steps in the right direction -- to make Bonneville more competitive. Bonneville must become more efficient at providing its services, streamline its processes, create clear and shorter lines of authority, empower its employees to make decisions, and eliminate the burdensome bureaucracy that creates the "hassle factor."

Caretaker Role

Bonneville has the responsibility to, and is uniquely situated to, protect the natural and built assets of the Northwest. At the heart of this role must be a reversal of the deteriorating condition of one of this nations most valuable assets, the Columbia River

Basin. We have decreased the ability of the basin to sustain fish, wildlife, timber, etc. We have done so without dedicating adequate funds to restore these resources. This trend must be reversed and Bonneville must take its role of caretaker of the Northwest's assets more seriously. Bonneville needs to ensure that it is capable of fulfilling the responsibility it has for the resources currently under its jurisdiction. None of the costs associated with Bonneville's past actions and choices should be placed at the feet of the nation's taxpayers.

In conclusion, it is vital that Bonneville become more competitive by focusing on a long-term perspective, by getting a handle on its expenses and employee levels (becoming a government corporation sounds like an excellent first step), by dealing forthrightly with its hidden costs, by coming to grips with the realities of decentralization in the industry, by restoring the public trust and accountability, by becoming more open in its decision-making, and by taking head-on the responsibility of caretaker of the Northwest's assets.

2. **Should BPA adopt tiered rates? If not, why not? If so, how should these rates be structured? If there is a specific model or framework for BPA tiered rates that you support, please describe it in detail. What principles should be used in the development of these rates? Can tiered rates be designed so that they do not discourage development of new industry in areas served by customers of BPA? Should federal base system resources be allocated through a tiered rate system?**

Yes, Bonneville should adopt tiered rates. The recent commitment by the Administrator to implement a tiered rate structure was made in the spirit of compromise and settlement of the rate case. Failure to follow through on the commitment will further erode the credibility of the agency.

The Administrator's commitment was based on a principle that tiered rates would serve to promote conservation. Others would prefer to see a tiered rate structure that reflects the price-specific resources. It is possible that both of these objectives could be achieved through a properly designed rate structure. The presumption that the existing Federal Base System (FBS) resources will be in a first tier and all new resources in a second tier assumes that new resources cost more than the existing FBS. In fact, as the costs of fish, wildlife and decommissioning are accounted for in the FBS, there is a potential that these resources will be more expensive than new resources. This begs the question: under any allocation scheme of the FBS, should the first tier be based on a take-or-pay basis?

Design of an appropriate tiered structure is being debated in the region. While Emerald's position is evolving, along with everyone's else in the region, as we learn more about the nuances of tiered rates. We present the following structure as a representation of our current thinking.

The goal of tiered rates is to send the correct market signal, i.e., the marginal cost of new resources, for acquisition of resources, especially conservation.

The Basic Structure

I. Two tiers based on resource pools: the first tier should be comprised of the FBS resources and possibly a limited number of others. The second tier should be comprised of new resources, including the Tenaska project.

II. The rate of the first tier should be the cost of FBS with fish and wildlife and conservation expenditures. The second tier should be based on the marginal cost of new resources

III. Allocations of the FBS should be carried out under the following guidelines:

1. Regional Preference should be retained. This means that public utilities and agencies get an allocation ahead of all others.
2. Allocations should be based on historical loads on Bonneville, giving the customer a choice of either a three year average or most recent year's load. The allocations should be weather adjusted, and based on monthly allocations (not hourly). The initial allocation formula should follow one of two alternatives: either 100 percent of a utility's priority firm load, or 75-to-80 percent of a utility's priority firm load. The latter alternative would ensure that all utilities would face the second, higher-priced tier and thus would create an immediate incentive to do conservation and other appropriate resource acquisition.
3. There are several alternatives under consideration for the initial firm energy services for the Direct Service Industries (the DSIs), but it should be clear that their firm power is provided by a contract for firm service and not an allocation.

IV. Allocations would automatically be adjusted with the addition of new Preference Customers (with reasonably short notice period) or the degradation of an FBS resource.

V. The alternatives for dealing with the residential exchange should include an up-front buy-out, a bifurcated or vintaged tiered rate for resources in each tier, and

the implementation of a formula that would fix the initial amount of the residential exchange that could vary based on the differential of average IOU and public retail rates.

VI. Utilities should have the option of relying on Bonneville or themselves for load growth services.

VII. Priority firm customers should have the right to assign their first tier allocations. This creates a market for conservation transfers. We should consider a queue for offering first tier allocations exclusively in the Northwest to publics, then IOUs or DSIs; and whether they should be offered to out-of-region publics and out-of-region IOUs. This right should include the potential for power pooling, where the pool would retain all of the efficiency gains that it would create from pooling.

IIX. Conservation programs should be offered to those utilities relying on Bonneville for load growth services. Emerald is intrigued by the notion of Bonneville regionally acquiring all cost-effective conservation, paying the participating utility's costs plus a premium, where all cost and revenues for the conservation would stay in the first tier, and Bonneville could resell the developed conservation savings in the second tier.

IX. Utilities that wish to develop resources other than conservation (and maybe renewables) should be required to do a least-cost plan. It is hard for public utilities to argue that they should not be required to do a least-cost plan, given nearly all of the region's IOUs are required to do a least-cost plan by state utility commissions, and that by law all Western Area Power Administration customers are required to do a least-cost plan. Without a least-cost plan we would question the basis by which resource acquisition decisions are made.

Least-cost planning "guidelines" should be developed by Bonneville and the Council, in a collaborative public process. The guidelines would be the evaluation criteria for an "acceptable" least-cost plan. Specific guidelines should ensure at a minimum that plans are consistent with the Council's planning process, meaningful public involvement, i.e., a Citizen's Advisory Committee, integrated resource planning, i.e., all resources included and on a "level playing field," full cost accounting of all costs including all environmental externalities. Environmental externalities should include at least a 10 percent conservation adder as provided in the Northwest Power Act, compliance with Council's Fish & Wildlife Plan, and appropriate environmental adders such as the Oregon Public Utility Commission's methodology or Bonneville's adders, explicitly including CO_2.

Utilities would file their least-cost plans with the Council for acceptance as consistent with the "guidelines." This is different than an approval of the contents of the least-cost plan; it is more a process check.

A penalty for resource development under a non-consistent least-cost plan should be established to ensure compliance. Several alternatives have been suggested including:
deducting the megawatts generated by the resource from the utility's first-tier allocation, or a monetary penalty, among others.

The plan should be updated every 3 years, or sooner if conditions warrant.

X. Tiered rates are not inconsistent with a simple and straightforward unbundling of products and services.

XI. Access to federal transmission at cost must be available for priority firm customers.

To answer the second part of the question about the relationship of tiered rates to new industrial loads, Emerald believes that tiered rates are not inconsistent with new industrial development. The message that we believe tiered rates provides is that growth should be paid for where it happens instead of being subsidized through regionalized rates. It is not a necessary conclusion that wholesale tiered rates need to be translated into retail tiered rates. Consumer-owned utilities enjoy the privilege and responsibility to determine retail rate structures best suited to achieve the goals of their respective communities. If a community chooses to encourage a particular activity, be that a new industrial load or a senior citizens housing complex, it is the choice of the elected directors to determine how to pay for that service. It is not appropriate for the region to shoulder the cost of an aggressive industrial development agenda of a particular community.

3. **BPA is considering unbundling the services it provides such as transmission, storage, load-shaping and integration services. What are the potential benefits and drawbacks of unbundling? If BPA pursues unbundling, what services should be unbundled and how should the price for these services be calculated? Are there some BPA services that can not be unbundled? Are you aware of any examples in either the public or private sectors of unbundled wholesale power services?**

Unbundling of a system as fully integrated as the federally base system operated by Bonneville will be a Herculean effort. The complexity of unbundled services has recently prompted senior Bonneville staff to question if unbundled services is

compatible to tiered rates. However, if done in a straightforward and simple way, unbundled services is not inconsistent with tiered rates. Emerald is concerned that Bonneville is considering unbundling services without tiered rates. In our opinion, unbundled services without tiered rates is a step backwards.

Bonneville is currently developing its "marketing plan," without the input of its customers, and is contemplating 68 unbundled products and services. Beside being extremely difficult, if not impossible, to determine the true cost of most of these products and services, it will be a nightmare for most utilities to deal with such a long laundry list. Emerald believes that Bonneville needs to keep the list as simple as possible. A list of 68 products and services is not simple.

The benefits of unbundling products and services is that many of the utilities seeking to develop their own resources will likely be able to become more independent. Having access to these services will create flexibility and opportunity that would otherwise be impossible to achieve. This is the purpose of unbundling.

A drawback to unbundling is that private providers can in the short-run subsidize select products and services in order to capture market share and to compete with Bonneville, and in order for Bonneville to be competitive in that market segment it will have to shift costs to some other product or service. This cross-subsidization could severely distort the market. As well, once products and services are unbundled, even if it is kept simple it will still be quite complex. This will create a distinct advantage for those larger and more sophisticated utilities accustomed to dealing in similar products and services. In addition, the provision and price of these products and services will be susceptible to undue influence from these large sophisticated utilities, probably to the detriment to smaller utilities. Finally, it is our fear that valuable public products and services will be acquired to a much larger degree than today to increase profits for IOUs. This is not an appropriate result of unbundling. Smaller utilities just entering the resource development arena will be severely disadvantaged without adequate protection such as the application of preference and recall rights for services sold to IOUs or out of the region.

Several services should be included at a minimum to provide for continuity and a smooth transition. Unbundling should create the ability of utilities to rely on Bonneville for load growth services. A rebundled package of products and services that looks, smells, and feels like priority firm power today should be a service offered by Bonneville.

The provision of unbundled products and services is not unusual. There are numerous examples of both public and private as well as non-utility marketing activities for products such as scheduling, dispatching, firming, wheeling, billing,

meter-reading, engineering design, construction, public relations, etc. However, to our knowledge no one has done it on quite the scale Bonneville is contemplating.

Through the competitiveness project, every single function of the agency should be structured to compete with alternative providers of the respective service. To add value, Bonneville should be allowed to provide service outside the agency where they can compete (for example, engineering design, contract negotiations, printing, public relations, etc).

4. **How should the costs of environmental externalities, including the costs of restoring endangered fish and other species, be distributed in tiered rates and/or unbundled services? What must BPA do to insure that competitiveness efforts such as tiered rates and unbundling do not diminish its commitment to statutory requirements such as the protection of fish and wildlife? How can the region maintain the benefits of regional coordination and planning if resource acquisition and transmission become more decentralized as a result of tiered rates and unbundling?**

Congress should ensure that Bonneville pursues a policy that includes the cost of carbon dioxide in its resource planning activities. The practice of excluding CO_2 is not based on science but the politics of a past administrations and it should be overturned! The CO_2 issue is like the crazy aunt in the basement, everybody knows she is down there but nobody wants to talk about her. Bonneville must include CO_2 in its analysis!

The effect of including CO_2 in the analysis would be to increase the amount of conservation and renewable resources in the resource acquisition mix, and to reduce the amount of gas resources acquired. We are fairly certain that a reasonable adder for CO_2 in the cost analysis of resources alone (not to mention full-cost accounting and the inclusion of other underestimated environmental impacts) would indicate that there is an abundance of other conservation and renewable resource that are more cost-effective than Tenaska, or in the least that the acquisition of Tenaska is premature. Bonneville's bet with Tenaska is that the CO_2 externality will never be formally internalized. This is an unwise bet in our minds and others'.

When applying environmental externalities to tiered rates and unbundled products and services, it is clear that all direct costs attributable to a particular project should be included in its applicable tier. For example, the cost of protecting the endangered salmon must be included in the first tier if the FBS hydro projects are in the first tier.

However, what is less clear is how one would include indirect environmental costs. For this reason the treatment of the price for second tier resources it is not as apparent.

Unless the entire region is playing by the same rules with regard to externalities, some market distortions can occur. There exists a dilemma between what is appropriate for planning as opposed to what is appropriate for pricing. It is necessary to include environmental externalities in the planning and selection of resources so that we account for all costs and choose the resources with the least long-term cost to society. (It is not likely that the people of the Northwest, let alone the citizens of the United States, will accept decimation of Columbia River fishery or other natural resources of the drainage, in order to preserve Bonneville's competitive position. This is particularly true given the rate differential between the region and the rest of the country.) But if Bonneville were to add several mills to the price of second tier power to account for environmental externalities and competitors did not do the same, Bonneville's product might be uncompetitive before it even hit the streets. If all competitors are required to play by the same least-cost planning rules that include environmental externalities in the planning and selection of resources, then no market distortions occur. The question is whether including environmental externalities in the planning and selection process alone is sufficient to send the correct market signal to acquire the least-cost resources in the long term for society.

When applying environmental externalities to unbundled services, it is extremely difficult to assign certain externalities to certain services. Parts of the existing federal generation and transmission system do not exist independent of each other. Applying the environmental cost of first-tier resources across-the-board to all unbundled products and services might be the most expeditious and equitable method of distribution.

To ensure that Bonneville's statutory requirements, such as those to protect fish and wildlife are not diminished, it should be a requirement of those who wish to purchase tiered rate power or unbundled products or services that they adhere to all existing laws and regulations, adhere to the Council's Fish & Wildlife program, and adhere to the least-cost planning "guidelines" mentioned in question number 2 about tiered rates.

To ensure that we maintain the benefits of regional coordination and planning, we should require those wishing to acquire resources other than conservation (and maybe renewables) to do least cost plans consistent with established "guidelines" which should include environmental externalities (see question 2 about tiered rates), and to encourage cooperation among utilities.

Finally, it is important to distinguish regional planning from regional acquisition of projects. We are increasingly questioning the benefits of regional acquisition of resources as it presently functions. Regional acquisition has served to prevent Emerald PUD's billpayers from understanding the consequences of the resource choices being made for them by Bonneville. We have asked for a copy of the Tenaska Contract. We have asked for a copy of the WPPSS/GE settlement agreement, and we have asked for a copy of the EWEB/BPA Trojan Agreement. None of these agreements have been provided, yet we are obligated to pay for all of these regional acquisitions.

There are certain economies that come from regional coordination, but those economies are not likely to be lost in decentralized resource acquisition and development if we encourage cooperation among utilities in the context of least-cost planning.

5. **Should the variable rate for the Direct Service Industries (DSI) be eliminated or modified? Please provide an estimate of the cost and/or benefit to the regional ratepayers of continuing to provide this variable rate. What is the current value of reserves (VOR) of the first quartile of the DSI allocation? What is the current VOR of the second quartile?**

The region can no longer afford to offer artificially priced power to select industrial loads. There has been significant debate in the region as to the true cost and benefit of maintaining the variable rate. Regardless of the costs and benefits, and regardless of the rationale for the original decision to offer variable rates, the reality is that in an era of energy deficit and economic hard times, the region cannot afford the subsidization of power for selected loads.

Specifically to the Value of Reserves (VOR), the original analysis (prepared by Bonneville in 1985) is based on the cost of a proxy gas turbine (the alternative source of reserves if Bonneville could not restrict the DSIs' firm power loads). Put another way, the VOR attempts to estimate the cost to Bonneville of acquiring sufficient gas turbine reserves if the DSIs had firm power contracts without restriction rights.

The analysis showed that the value of DSI reserves in 1985 was approximately $90 million. To this amount was added to the projected cost to the DSIs of a Bonneville power outage. The two items totalled about $92 million. Half of this amount -- $46 million -- was then allocated to the DSIs as a credit (discount) on their annual power bills. This value escalates with inflation, and is now about $60 million.

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The VOR, however, is based on two important assumptions, both of which now appear to be out of date and should be modified. The first is that the DSIs provide two quartiles (about 1,200 megawatts) of capacity reserves for Bonneville's planning purposes. That was generally believed to be the case until January 1993, when Bonneville published the new Pacific Northwest Loads and Resources Study (the White Book), which showed that Bonneville now only counts one DSI quartile (about 600 megawatts) for reserves. This reduction should trigger a re-evaluation of the VOR to ensure that it accurately reflects Bonneville's current planning assumptions. The other assumption that warrants a change in the VOR is that the gas turbine proxy cost (the plant that would have been acquired if the DSIs did not provide reserves) is based on a 14 percent interest rate. A 7 percent figure more accurately reflects today's market.

Unfortunately, the VOR cannot be modified automatically to reflect either the reduction in the quartiles used for planning reserves or the lower interest rate. The reason is that Bonneville "locked in" the essential components of the VOR in 1987. The "lock" was approved as part of the IP-PF Rate Link, a Bonneville rate proceeding; it expires in mid-1996. The effect of the lock -- if interpreted strictly -- is to preclude testimony during the 1993 rate proceedings on the value of reserves. The idea of an administrative "lock" -- in which key elements are frozen in time and cannot change -- is a legal and policy issue that ought to be examined more closely, and we argue should be changed.

6, 7, and 8.

Should the irrigation discount, low-density discount, or other discounts be eliminated or modified? Please provide an estimate of the cost and/or benefit to regional ratepayers of continuing to provide this discounts.

The region can no longer afford to offer artificially priced power to select industrial loads. There has been significant debate in the region as to the true cost and benefit of maintaining the variable rate. Regardless of the costs and benefits, and regardless of the rationale for the original decision to offer variable rates, the reality is that in an era of energy deficit and economic hard times the region cannot afford the subsidization of power for selected loads. However, Bonneville should not selectively determine which subsidies have a higher social or political value and keep them, while eliminating others. Bonneville should treat all of these subsidies equally and fairly. In a truly competitive environment there would be no subsidies at all.

9. Should the provisions in the power sales contract which allow some utilities to be reimbursed by BPA for lost revenues when a voluntary curtailment is implemented be eliminated? If so, why? If not, why not?

Yes, in fact the concept of voluntary curtailment needs to be reevaluated in light of current conditions in the region. The obligation to pay lost margins for voluntary

curtailment effectively eliminates the value of the DSIs' second quartile to the region. Prior to exercising restrictions on the second quartile, Bonneville must call for voluntary curtailments in the region. If Bonneville must pay lost margins for this saved power there is significantly less value for the restriction rights on the second quartile.

10. How should the long-term power contracts that BPA is currently negotiating differ from the current contracts? What, if any, environmental issues should be addressed in these contracts?

The existing power sales contracts need to be substantially revised to incorporate the changes in the industry and to allow Bonneville to become more competitive. For example, new contracts will be required to deal with: tiered rates, changes to Bonneville's role as a regional energy supplier, a shift to unbundled products and services, new transmission access requirements, changes to the Residential Exchange, changes to how we meet reserve requirements, and how we would modify the contracts once signed.

The new power sale contracts should address as many environmental issues as possible that are not dealt with in present or future forums by other appropriate agencies. Such issues should be substantially and functionally related to some provision of the new contracts, or be a solution or corrective action to an existing problem, and be able to be reasonably implemented by the parties to the contract. Specifically, this would include the Council's Fish & Wildlife Plan, a least-cost planning requirement, and the inclusion of externalities for both Bonneville and utilities.

11. It has been suggested that the residential exchange program rewards less efficient utilities. Are revisions to the exchange agreements necessary? If so, what changes would you suggest?

The residential exchange is a complex arrangement that may well reward inefficiency. For example, the residential exchange is about to become a conduit for further regionalization of the cost of Trojan. Clearly, if tiered rates are adopted, changes to how the exchange is calculated will be necessary. Emerald has been considering several alternatives. Bonneville could eliminate this subsidy altogether, or could arrange for an up-front buy-out. Bonneville could create a vintaged or bifurcated system that would treat existing and new resources separately. Also, Bonneville could create a formula that locks in the exchange amount at current dollars with adjustments based on the differential of average IOU and public utility retail rates.

12. What part should BPA's existing resource acquisition programs play in BPA's competitiveness initiative, both during a transition period and after BPA has adopted some of the changes it is considering?

Bonneville needs to be an advocate not an adversary of utility participation in resource acquisitions. Bonneville will fail in its effort to be competitive if it cannot set the needs of its customers above its need for control and agency dominance. Emerald signed the first billing credits contract in the region. The decisions we made through the course of negotiating this agreement relied heavily on information provided by Bonneville. One year after we entered this agreement we were advised that Bonneville had significantly lowered their alternative cost. This was the result of a mistake Bonneville made in their original projections. The end result was a substantial reduction in the value of the project for Emerald. In trying to understand how this happened we were told that the error was a result of the final agreement reached on the Tenaska contract which was a key element in calculating the new benchmark for valuation of our billing credit contract. Bonneville went on to say they could not tell us how this valuation for Tenaska was arrived at because those numbers are vital to preserving the confidentiality of the Tenaska Agreement.

Under tiered rates and unbundling, Bonneville should still offer to provide load growth services for utilities. In order to effectively accomplish this service Bonneville must at least maintain existing conservation programs. The new idea that Bonneville would acquire all regional conservation, as described in question 2 about tiered rates, is quite intriguing.

Billing credits would likely have no meaning and should probably be eliminated.

13. Please provide any other suggestions regarding actions that would make BPA more competitive or cost-effective?

<u>Government Corporation</u>

Bonneville is actively pursuing "Government Corporation" status. This may provide the Administrator the ability to manage the entity more in line with conventional business practices as opposed to traditional bureaucratic processes. Personnel management practices need to be more responsive to rewarding and promoting deserving employees, and termination where services are no longer necessary or performance is substandard. Authority to make decision must be delegated to the regional offices, or the regional offices should be closed and all decision making come out of headquarters.

While we support the concept of transforming Bonneville from an agency to a Government Corporation, we caution against allowing this new status to be used as an additional mechanism to distance Bonneville from public scrutiny of all of its actions. There were five attempts between 1937 and 1958 to convert Bonneville Power Administration (BPA) into a Columbia Valley Authority (CVA). Most were driven by frustrations over the difficulties of securing appropriations from congress for capital projects. The new initiative to turn BPA into a government corporation has the appearance of a sixth attempt at forming the long sought CVA. This new effort is being brought forward without draft legislative language which would clarify the intent of the effort and give purpose to the outcome. Is the intent to establish the goals of the 1935 CVA bill proposed by U.S. Senator James Pope? This bill provided broad non-power planning authority similar to that vested in the TVA. Or, is the intent to devise a TVA-like regional control, removing the regional system from national debate. We understand this new initiative is to give flexibility to the agency and reduce reporting requirements to other federal agencies -- benefits enjoyed by TVA. However, TVA is subject to a governing body which is not proposed for the new BPA Corporation.

Repayment Reform and Debt Buy-down

We support the recent proposal for Bonneville to "buy-down" the existing payment stream on its $6.9 billion debt, providing a buy-down actually produces a benefit to the federal government in the form of a reduction to the national debt. However, the proposal must be "rate neutral" to Bonneville's consumers. In order to accomplish this, it will be necessary to provide flexibility in determining the discount rate. The "scoring" of this repayment must reflect the true value of buying out the debt. Bonneville needs to make clear to the region's billpayers how the relationship to the financial life of existing transmission and generation assets will change. We understand the existing transmission and generation assets have 15 and 25 year financing lives remaining. Under the new bonds these may be extended to 40 years.

We make the assumption that Bonneville will be allowed to secure private capital by issuing paper "implicitly backed by the U.S. Government." Recognizing the enormous liabilities Bonneville has assumed in its nuclear obligations, the secrecy of the terms of the Tenaska contract and the WPPSS/GE settlement, and the uncertainty of the Endangered Species Act impacts on the hydro system, it is not likely that Bonneville could issue bonds without the backing of the federal government.

CONCLUSION

In closing, I would like to say that I believe Bonneville has done an excellent job in fulfilling its original mission, bringing low-cost power to rural areas of the Pacific Northwest where IOUs refused to provide service. As we approach the twenty-first century, Bonneville will take on a different role in the region. One with, as President Eisenhower described, "the Federal Government drawn-in as a cooperating partner where this seems necessary or desirable."

Our mutual best interest will be served by an agency that the region finds is not necessary but is clearly desirable.

STATEMENT OF DAVID PIPER

Mr. PIPER. I am Dave Piper, the general manager of the Pacific Northwest Generating Cooperative. We are a generating and transmission cooperative that serves 27 distribution co-ops in the Bonneville service area, primarily serving the rural areas, the hard-to-serve areas, and the costly ones with few customers.

These systems are not-for-profit; they are controlled by elected directors elected from the membership.

PNGC owns 10 percent of the Boardman project. We have sold the output on a long-term basis to Turlock Irrigation District and we are participating in Bonneville's Third AC in order to move that power into California.

In addition to looking for new resources at this point, we also are basically informal agents of our members, trying to deal with the issues before Bonneville, looking out hopefully for their best interests and power supply.

Rather than echo all of the things that been said about the need for Bonneville competitiveness from this morning's session, I thought I might give you some practical experience, things that we are going through right now in dealing with these issues at PNGC on behalf of our member systems.

We are required to do least-cost planning. The federal agency under which we have borrowed money historically, REA, requires a least-cost plan for co-ops that are financing any generating resource. And certainly from our members' standpoint, it makes sense to do least-cost planning. We are not in business to do anything other than provide them with the least-cost and most reliable power.

As we look at resources, the 30 mill resource has been thrown around this morning, and people are accurate when they say that is a busbar cost. There would have to be added to that the services that are appropriate and necessary. But I can tell you there are 30 mill resources—at least people are telling us they can develop 30 mill resources—with relatively firm gas prices. To that you have to add the services that are necessary, and there are a lot of those out there. They may not be the best thing in the world, but as Bill Drummond said this morning, there is risks in staying where we are. And so what we have to evaluate is the forecast for the Bonneville rates in the future under the present structure of average costing. We have to evaluate not just today's price of 27 or 28 mills, but we have to evaluate where we think that is going. The uncertainties surrounding that right now put a tremendous delta or range band-width in what those future costs can be.

Granted there is uncertainty when you are dealing with combustion turbines and any other resource as well, and we have to face those and make hopefully consciously good decisions.

Our strategic plan at PNGC is to provide 25 percent of our members' total load by the year 2000, if we can do it effectively on a cost basis. I am not here to tell you that that is possible, but we are certainly evaluating and trying to find any of those resources that we can do that. That is under the present pricing structure from Bonneville.

Alternatively, if and when we go to tiered rates, we are convinced that we can provide resources cheaper than Bonneville and we will

provide the resources that are necessary to meet their load growth beyond the tier 1 allocation.

So what we are looking at today are conservation—but I have got to tell you under the present pricing structure at Bonneville conservation for our members is not a very do-able resource—methane-derived generation from landfill projects, and combustion turbines. Those are the three cost-effective resources that make sense in today's economic picture.

Today's average pricing provides the wrong decisions, the wrong basis for our decision-making for the future. We truly believe that we can make better resource decisions. We have unique needs, the rural areas have unique needs, and we believe that we have a lot lower costs in developing. And I do not believe that this compromises the central planning concept. In a sense, PNGC is a central planner. It may not be a public body in the true sense of the word public, but it is directed by elected officials. And we are representing 27 systems, so that is a group for which we can do central planning. We would be the pool. And the market will really dictate the economic good for that pool.

There are a number of acquisition possibilities and there is diversity in those possibilities. I think having diversity in planning can lead a group to make the right decisions by picking and choosing and basing your decisions on experience of other people as well.

Central planning, in and of itself, is not necessarily a panacea—it is a good process, and I do not deny that. But it has resulted in some bad decisions in the past.

Tiered rates are complex to implement, but they are pretty simple in philosophy, at least in my philosophy of what tiered rates should be. And that is, that we have to protect the federal base system in order that we can get the benefits of that tremendous resource and to be assured of repaying Treasury. And each tier has to be based on the cost of the resources in the tier.

If we have the ability to choose for our tier 2 resources or our resource beyond the tier 1 allocation, based on the incremental cost from tier 2, we are going to choose conservation, we are going to choose to develop our own resources, we are going to choose to go with Bonneville, or buy from others. Those are all the options that are available to us.

Unbundling goes right along with tiered rates. It is not possible for an entity such as ourselves to provide power on any basis to our members without those services. We would have to buy them from some source. Bonneville is a very good provider of those services, but not necessarily the only provider, except in the case of transmission.

This is a scary process for us because in the rural areas we have a fear that as these things become unbundled we may be forgotten in the process, with more emphasis on urban areas.

Turning now to the low-density discount, the origin is the Regional Power Act. Congress recognized when it was passed the need to mitigate the problems of the rural areas and the disadvantages in order to keep these rural areas competitive and economically viable. They realized that there were already problems with transportation and water and sewerage and medical facilities, and they did not want to compound that with causing higher rates for

basic services such as electricity. A real indication of that economic hardship I think is the fact that none of these systems that have low-density discount benefits have been taken over by the surrounding systems, even though the rates of most of the surrounding systems are much lower. The high-density systems originally did not want the co-ops and the rural areas and that was the reason the co-ops formed, and they still do not.

However, one of the concerns that we have is, especially with the possibility of retail wheeling, is the potential for cream skimming. Take these good loads, the few that do exist, the dense loads of the rural systems, without the low-density discount, and those rates are going to become higher for all of the customers in rural areas and certainly the good loads will see higher rates and will have political motivation to try to find alternative suppliers, thus exacerbating the problem of the customers who do not have a choice in rural areas.

The cost of the low-density discount is relatively small, it is $24 million average per year in the 1994–1995 rate period. That benefit is very significant because it is spread over relatively few customers, but in the overall Bonneville budget, it is relatively insignificant.

There have been a couple of major reviews of the low-density discount. There have been safeguards added to it over time; the discount declines as the density increases, so it is not just one number. And it is even more important today, frankly, than when it was originally created by Congress.

In conclusion, the regional energy in the Northwest is going to be market-based, it is inexorable, and it is important for Bonneville and the rest of us to get ready for that situation. The unbundled services and tiered rate concepts, if correctly implemented and applied, are necessary tools for becoming competitive. Finally, I appeal to you and to everyone not to forget the importance of the rural economy as these changes take place.

Thank you for your time.

Mr. DeFazio. Thank you. Mr. Scarborough.

[Prepared statement of Mr. Piper follows:]

David E. Piper
Pacific Northwest Generating Cooperative
Testimony on Competitiveness
BPA Task Force,
House Natural Resources Committee
9/25/93

Mr. Chairman:

My name is Dave Piper and I serve as Executive Vice President and General Manager of the Pacific Northwest Generating Cooperative (PNGC). PNGC is a generation and transmission cooperative that was formed in the mid-70's and currently serves 27 rural cooperatives spread out over eight Western states. On behalf of those cooperatives and the over 500,000 consumers that they serve, thank you for the opportunity to testify today.

It is interesting to note that five short years ago competitiveness was not an issue discussed much in Northwest energy circles. At that time Bonneville's customers were not looking for non-Federal resource acquisition. BPA was locked in a battle with the Office of Management and Budget not over burdensome regulations but over BPA's desire to add more employees than their FTE limit allowed. It looked like the regional power surplus could last through the decade, aluminum prices would stay high, and BPA could absorb all sorts of additional fish and wildlife mitigation costs.

It is amazing what a difference continued drought, salmon listings, and a downturn in world aluminum prices can make. Unfortunately, we cannot change all of those factors, we must react to them. PNGC believes that those reactions must take the form of a leaner, more responsive BPA and the regulatory flexibility to allow BPA customers to make their own resource decisions. In other words, BPA and Northwest energy markets need to become more competitive.

Fortunately, we have in Randy Hardy an Administrator who believes in competitiveness and knows that the financial integrity of Bonneville supersedes the importance of any one element of its budget. In launching Bonneville's "Function by Function Review", Mr. Hardy is acknowledging that times have changed and Bonneville must change with them. The possibility of a new regulatory landscape that includes tiered rates and unbundled services, if constructed properly, also brings hope that we can meet the challenges ahead.

While PNGC and its members support making the changes necessary to build a more competitive BPA, we believe that those changes must

follow several guidelines. Bonneville must focus on the things that it is good at and leave the rest for others to do. That means helping the overall competitiveness of the system -- even if it means that Bonneville may not always be the monopoly player they now are. Those areas where BPA clearly has a role include running the transmission system and maintaining and optimizing the use of the existing Federal Base System (FBS). However, competition should guide decisions on who is best suited to acquire new resources to meet load growth.

Unfortunately, BPA has not shown itself to be a low-cost supplier of resources. Its higher resource acquisition costs are driving up BPA's average (melded) cost. This in turn is undermining the very underpinning of the Northwest's economy, low-cost Federal power resources. We believe that the way for BPA and the region to get the most for its resource acquisition dollar is to create a truly competitive market for new resources. There is no reason BPA should not have to compete with non-Federal power suppliers in the overall effort to meet new regional power demands. Competition will ensure that the lowest cost options prevail.

PNGC is very interested in seeing a leaner, more customer-oriented BPA. Currently, all of our members are net-requirements customers of BPA. Accordingly, we have a direct interest in promoting a more cost-efficient agency. That, in turn, results in lower costs passed on to the ratepayer. A leaner, more competitive Bonneville will protect jobs, consumers, the environment, and the ability to provide for repayment of BPA's Federal debt obligations.

PNGC is also, however, well situated to react quickly to a less-efficient BPA and/or a more competitive environment. PNGC has experience in resource acquisition, and has a membership interested in providing more diversity to its resource mix. Accordingly, we are actively seeking alternative resources to provide for the growth of PNGC member-system loads.

Tiered Rates

Currently, Northwest public utilities face an average or melded cost for all of the power they purchase from BPA. This average rate, the Priority Firm (PF) rate, melds the cost of more expensive new resources with the enormous, low-cost FBS hydro resource. Faced with this average cost for incremental load, Northwest utilities are hard-pressed to economically justify buying new resources themselves, thereby losing the melding effect of the BPA rate. Accordingly, the market for new power resources has not fully developed. Without a tiered rate structure in which incremental load is served at the actual cost of incremental resources, a truly competitive market cannot develop and the system is left bearing higher acquisition costs.

A tiered rate system would put all resource acquirers on an even footing -- providing a new competitive atmosphere while preserving BPA's ability to repay the Federal investment in existing

resources. While instituting such a system would be a complex undertaking, the keys to making it work are fairly simple. The prices in each tier have to be based strictly on the costs of the resources in that tier. In order for Bonneville to compete fairly to meet load growth, it must bear all of the costs of new resource acquisition in that tier. It is essential that the existing Federal Base System should not be loaded up with unassociated costs.

The first priority of Bonneville must be to keep the Federal Base System competitive. We are nearing a point at which customers may choose to reduce their reliance on BPA, leaving fewer ratepayers to cover a greater share of the costs. A tiered rate system, if constructed correctly and coupled with some rational limitation on ever-increasing fish and wildlife mitigation costs, would allow BPA's customers to continue to benefit from the FBS -- ensuring its financial stability.

Unbundled Services

Unbundling services is another measure that, structured correctly, would help give customers the flexibility to make their own resource decisions. Why is unbundling so vital for the success of BPA and the region? When BPA delivers power at a utility's point of delivery, it is delivering more than just energy and demand (power). It is also delivering transmission services, load shaping, and generation control (including prescheduling, dispatch, reserves, and control area operation). In order for other utilities to deliver power to their systems, they must have access to these other services. Some of these services can, in the short and medium term, be delivered only by BPA.

In a future where BPA has adopted tiered rates and unbundled its services, the most economic resource decisions can be made. For example, if BPA is a low-cost supplier of new power resources, utilities will continue to buy incremental power from BPA. If other power suppliers are competitive with BPA, then they can use specific BPA services to support independent resource development and deliver a product comparable to BPA's. Unbundling of generation control and transmission services will allow the cost of those services to be separated from the resource costs. These services must be priced at the actual cost of providing them. This will allow BPA to provide those services at which it excels, while allowing for the creation of a competitive market for power resource development.

Low Density Discount

Because PNGC's member cooperatives are primarily rural, PNGC is especially concerned about how BPA operations affect the rural areas of the Northwest. The Low Density Discount (LDD) plays a key role in allowing agency-provided power to be competitive in remote and sparsely-populated areas. The LDD has its origins in the Regional Act, Section 7(d)(1) which reads:

> "In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates of such customers."

In approving this provision, Congress clearly recognized the need to maintain the economic viability of the Northwest's rural areas which have high distribution costs due to difficult terrain, remote service areas, or other factors.

The economic hardship that the low-density systems face is illustrated by the lack of mergers or take-overs of these systems. Despite much talk, no system receiving the LDD has been taken over or merged with a better positioned system even though many neighboring systems have substantially lower rates. Why not? These utilities have such high distribution costs that they would merely serve to raise the average cost of doing business of the better positioned system. The IOU's would not serve these areas initially because there was no profit in them; the situation today is no different.

This does not stop other utilities from trying to acquire the portions of low density systems that have become attractive -- a practice known as cream skimming. Without the LDD, the rates of low-density systems would be even higher and would encourage even more competition for the more densely populated areas, potentially destroying the overall economic viability of these systems.

BPA has had two major reviews of the LDD. Its customers were active in these processes. As a result of these reviews and subsequent implementation of its recommendations, many safeguards and eligibility criteria have been added to the LDD. Additionally, the discount itself contains a sliding scale under which utilities who qualify receive discounts that diminish with increasing density.

Most importantly when viewed from a competitiveness aspect, the Low Density Discount adds no net cost to the Priority Firm rate class since the cost of the discount ($24 million/year average over the 1994-1995 test period) is allocated back to the Priority Firm rate class. It is a redistribution within this rate class and does not impact other BPA rate classes.

Conclusion

In summary, it is vital to the Northwest that regional energy markets and the Bonneville Power Administration become more competitive. Efforts towards that end should focus on internal efficiencies as well as on BPA's role as a supplier of power, generation control, and transmission products. These products should be priced at the cost of providing them and the regulatory environment should be reshaped to provide for more competition.

If Bonneville is indeed the most efficient provider of new power

resources, the market will quickly show this. But if it is not, independent resource development should have access to the other products and services required to integrate resources into the power grid. Either way, a new, competitive atmosphere will ensure low-cost power to meet future needs. By adapting to our new energy circumstances, we can help the Northwest economy to remain strong nationally and internationally while preserving the way of life in both urban and rural areas.

Thank you, Mr. Chairman and members of the Committee for your leadership in exploring ways in which we can move forward to assure that these goals are met.

STATEMENT OF KERMIT W. SCARBOROUGH

Mr. SCARBOROUGH. Thank you, Mr. Chairman. My name is Kermit Scarborough and I am chairman of the Canby Utility Board.

Our utility serves the city of Canby, Oregon, population 10,000. We are entirely dependent on the Bonneville Power Administration for electricity.

Much has been written and said today about Bonneville's efforts to become more competitive and business-like. These are laudable goals, but we also need Bonneville to become more accountable, and I would like to spend my time today addressing a major area of concern, one that impacts the rates and power supply of every utility in the Northwest.

I am talking about Bonneville's long-standing relationship with the Direct Service Industries. The DSIs are subsidized by Bonneville and receive special treatment in the amount and price they pay for power. The more that subsidies go to the smelters, the more other customers around the region pay for electricity.

The thrust of my testimony is that we need your assistance in ending some of the lucrative DSI subsidies and in ensuring that the contractual arrangements that Bonneville strikes with the DSIs is fair to the public utilities, like Canby, which by statute are Bonneville's preferred customers.

In the time allotted me, I wish to make three basic points regarding (1) competitiveness; (2) the new power sales contract renegotiation process; and (3) the need for a thorough GAO review of the Bonneville-DSI relationship.

(1) Competitiveness. Bonneville's competitiveness initiative cannot and will not succeed unless Bonneville reevaluates its relationship with the DSIs. Bonneville, in our opinion, must end the two significant subsidies it now bestows on the DSIs: the variable industrial rate for aluminum smelters and the out-of-date methodology for calculating the value of DSI reserves.

The variable rate applies only to aluminum smelters. It increases when the price of aluminum goes up, and decreases when the prices drops.

Because aluminum prices are low, Bonneville now loses about $32 million a quarter at this rate, compared with what the smelters would pay under the standard industrial firm power rate.

It seems to me as a utility official that Bonneville has gambled its financial security on a volatile, international commodity over which it has no control.

It is inconceivable that Canby or any other public utility in the region would speculate with its future revenue stream that way.

With regard to the value of reserves, I must tell you I believe Bonneville's method for paying the DSIs for reserves is also fundamentally flawed. The DSIs receive a discount on their power bill for providing reserves to Bonneville. In theory, the arrangement makes enormous sense to both Bonneville and the DSIs. The problem comes about in the way Bonneville pays for the reserves.

In 1987, Bonneville adopted what is known as the IP–PF rate link, which freezes the value of the reserves. The link was extended in 1991 and now expires in 1996, the same time as the variable industrial rate.

Several components of the link are now out of date, yet Bonneville has shown no interest in revising them to reflect current market conditions. In other words, Bonneville has locked into place a lucrative set of discounts for the DSIs. The more discounts the DSIs receive, the more the rate burden shifts to other customers, particularly the public utilities.

Bonneville's reluctance to do anything about the way the DSI reserves are priced is all the more troubling because Section 7(c)(3) of the Northwest Power Act requires the Administrator to adjust DSI rates to "take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service" to the DSIs.

(2) The Power Sales Contract Renegotiations. The power sales contracts must address the fact that DSIs are not preference customers of Bonneville and they are not entitled to as much firm power as they wish. Bonneville's primary legal obligation is to the preference customers, for whom the federal system was built.

That basic fact is often overlooked in the posturing and negotiating over new power sales contracts. The simple truth is that there is no mandate in the Northwest Power Act for Bonneville to sign new, firm power agreements with DSIs after initial contracts expire in 2001.

We are not suggesting that Bonneville cut off the DSIs when the existing agreements end. We do, however, believe that Bonneville has considerable discretion about setting the terms and conditions of new agreements:

1. Making one or more additional quartiles interruptible.
2. Providing firm power to DSIs in the summer only.
3. Offering a menu of options to the DSIs, including shorter term contracts for those companies that intend to close part or all of their operations within the next 5–10 years.
4. And linking rates to more energy-efficient production practices.

In sum, the new contracts should take into consideration the nature of the aluminum industry. The new agreements should discourage the DSIs from signing up for new 20-year contracts, unless they agree to remain in the region for the entire period (and pay a penalty if they leave early); and if they agree to pay rates comparable to the industrial customers of existing public utilities, as contemplated by the Northwest Power Act.

We would call your attention to the correspondence between Canby Utility Board and Bonneville regarding this issue. Attachment B contains the letters in question. In particular, we ask that you and your staff review Bonneville's assertion that Section 12 of the existing contracts obligates Bonneville to offer new firm power contracts to the DSIs.

(3) The need for a GAO audit to review the Bonneville-DSI relationship. The Bonneville-DSI relationship has not been subjected to an independent audit or evaluation since the passage of the Northwest Power Act in 1980. We believe it is time to conduct an independent evaluation of the relationship and to help answer a number of pressing questions about the Act and how it is being implemented in respect to DSI.

We suggest the General Accounting Office has the qualifications and experience to thoroughly evaluate a number of questions we have included in the text of my oral testimony. I have chosen not to read them now in the interest of time.

In summary, to deal with the variety of issues described above, we offer the following recommendations:

1. The BPA task force should request that Bonneville discontinue the variable industrial rate when it expires in 1996. The task force should take steps to require Bonneville to adjust the value of DSI reserves to accurately reflect current conditions.

2. BPA task force should assess Bonneville's legal obligation to the DSIs for future firm power contracts and should request that Bonneville consider a broad range of alternatives including shorter term contracts and greater interruptibility.

3. The BPA task force should request a General Accounting Office audit to examine BPA's relationship with the DSIs.

That concludes my oral testimony and I appreciate and thank you for letting me testify.

Mr. DEFAZIO. Thank you.

[Prepared statement of Mr. Scarborough follows:]

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IT PAYS TO OWN THE UTILITY THAT SERVES YOU

ORAL TESTIMONY OF MR. KERMIT W. SCARBOROUGH
Chairman
Canby Utility Board

Submitted to:

THE COMMITTEE ON NATURAL RESOURCES BPA TASK FORCE
September 25, 1993
Eugene, Oregon

Mr. Chairman and Members of the BPA Task Force:

My name is Kermit Scarborough, and I am chairman of the Canby Utility Board.

Our utility serves the City of Canby, Oregon, population 10,000. We are entirely dependent on the Bonneville Power Administration for electricity.

Much has been written -- and said today -- about Bonneville's efforts to become more competitive and businesslike. Those are laudable goals.

But we also need Bonneville to become more accountable, and I would like to spend my time today addressing a major area of concern, one that impacts the rates and power supply of every utility in the Northwest.

I am talking about Bonneville's long-standing relationship with the Direct Service Industries (DSIs).

The DSIs are sixteen companies that purchase power directly from Bonneville. Most of them are aluminum smelters, and they account for about one-fourth of all Bonneville's revenues. The smelters produce an important product, and they provide valuable employment to thousands of people in our region.

But the industries are subsidized by Bonneville and receive special treatment in the amount and price they pay for power. The more that subsidies go to the smelters, the more other customers around the region pay for electricity. There is no free lunch: someone will pay for the costs of operating the system of dams and power plants in our region.

The thrust of my testimony is that we need your assistance in ending some of the lucrative DSI subsidies and in ensuring that any contractual arrangement that Bonneville strikes with the DSIs is fair to the public utilities, like Canby, which by statute are Bonneville's preferred customers.

In the time allotted to me, I wish to make three basic points regarding: 1) competitiveness; 2) the new power sales contract renegotiation process; and 3) the need for a thorough GAO review of the Bonneville-DSI relationship.

We have focused on DSI issues because we believe they are traditionally underplayed by other public power organizations, and we wish to emphasize and call the Task Force's attention to them.

1. COMPETITIVENESS

Bonneville's competitiveness initiative cannot and will not succeed unless Bonneville reevaluates its relationship with the DSIs. Bonneville, in our opinion, must end the two, significant subsidies it now bestows on the DSIs: the variable industrial rate for aluminum smelters and the out-of-date methodology for calculating the value of DSI reserves.

The variable rate applies only to aluminum smelters. It increases when the price of aluminum goes up, and decreases when the price drops.

Because aluminum prices are low, Bonneville now loses about $32 million a quarter on this rate, compared with what the smelters would pay under the standard industrial firm power rate.*

The variable rate has fluctuated wildly in the last few years when the price of aluminum skyrocketed to $1.30 per pound in 1988 and then plunged within a four-year period to about 52 cents.**

It seems to me as a utility official that Bonneville has gambled its financial security on a volatile, international commodity over which it has no control.

Whether the variable rate is a success or a disaster is a matter not of good management or cost-cutting or clever, business initiatives, but of luck.

It is inconceivable that Canby or any other public utility in the region would speculate with its future revenue stream that way. We would reject that approach not because of hostility to the aluminum industry, or because we are insensitive to the cycles of business, but because traditional standards of prudent utility ratemaking demand that we retain control over the utility and its sources of revenue.

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** For data on the swings in aluminum prices between 1980-88, see Table 6 (Historical Aluminum Price Cycle Analysis), page 19, Documentation for the Loads and Resources Study: Volume 1, Bonneville Power Administration, 1993 Final Rate Proposal.

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The DSIs receive a discount on their power bill for providing "reserves" to Bonneville. Instead of building standby generating resources that can operate in case of a plant malfunction, Bonneville can shed load and restrict DSI operations under certain circumstances.

In theory, the arrangement makes enormous sense to both Bonneville and the DSIs. The problem comes is in the way that Bonneville pays for the reserves.

In 1987, Bonneville adopted what is known as the "IP-PF Rate Link," which freezes the value of DSI reserves. The Link was extended in 1991 and now expires in 1996, the same time as the variable industrial rate.

Several components of the Link are now out of date, yet Bonneville has shown no interest in revising them to reflect current market conditions.

In other words, Bonneville, which has such outspoken pretensions to become more competitive and businesslike, has locked into place a lucrative set of discounts for the DSIs. The more discounts the DSIs receive, the more the rate burden shifts to other customers, particularly the public utilities.

Bonneville's reluctance to do anything about the way that DSI reserves are priced is all the more troubling because Section 7(c)(3) of the Northwest Power Act requires the Administrator to "adjust" DSI rates to take "into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service" to the DSIs.

More information on DSI reserves is contained in our supplemental testimony at pages 17-24, and in **Attachment A**.

2. POWER SALES CONTRACT RENEGOTIATIONS

The new power sales contracts must address the fact that the DSIs are not preference customers of Bonneville and that they are not entitled to as much firm power as they wish. Bonneville's primary legal obligation is to the preference customers, for whom the federal system was built.

That basic fact is often overlooked in the posturing and negotiating over new power sales contracts.

The simple truth is that there is no mandate in the Northwest Power Act for Bonneville to sign new, firm power agreements with the DSIs after the initial contracts expire in 2001.

We are not suggesting that Bonneville cut off the DSIs when the existing agreements end.

We do, however, believe that Bonneville has considerable discretion about setting the terms and conditions of new agreements, and that it ought to sell firm power to the DSIs only after careful consideration of different alternatives, including the following options:

1. Making one or more additional quartiles interruptible (at present, only one quartile is interruptible).
2. Providing firm power to the DSIs only in summer.
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4. Linking rates to more energy efficient production practices.

In sum, the new contracts should take into consideration the fickle nature of the aluminum industry.

The new agreements should discourage the DSIs from signing up for new 20-year contracts, unless they agree to remain in the region for the entire contract period (and pay a penalty if they leave early); <u>and</u> if they agree to pay rates comparable to the industrial customers of existing public utilities, as contemplated by the Northwest Power Act.

If the DSIs sign 20-year contracts but leave after the 5th year, the region may be stuck with new power plants -- perhaps as much as several thousand megawatts -- and no industrial customers to buy power. Bonneville can, of course, sell this power on the surplus market, but it will likely lose money doing so, and the preference customers will pay more to make up the revenue shortfall.

Unfortunately, Bonneville seems to have adopted the position that it is under an obligation to continue the status quo, to continue selling large quantities of firm power to the DSIs, as if they were preference customers.

We would like to call your attention to correspondence between the Canby Utility Board and Bonneville regarding this issue. **Attachment B** contains the letters in question. In particular, we ask that you and your staff review Bonneville's assertion that Section 12 of the existing contracts obligates Bonneville to offer new firm power contracts to the DSIs.

3. THE NEED FOR A GAO AUDIT TO REVIEW THE BONNEVILLE-DSI RELATIONSHIP

The Bonneville-DSI relationship has not been subjected to an independent audit/evaluation since the passage of the Northwest Power Act in 1980.

We believe it is time to conduct an independent evaluation of this relationship and to help answer a number of pressing questions about how the Act is being implemented with respect to the DSIs.

We suggest that the General Accounting Office has the qualifications and experience to thoroughly evaluate these and other related questions:

1. **Did Congress intend that Bonneville offer long-term, firm power contracts to the DSIs indefinitely, no matter what load-resource balance Bonneville faces? If the answer is no, what alternative relationships did Congress contemplate when it enacted the Northwest Power Act?**

2. **What is the likelihood that the DSIs will remain in the region, and what are the likely rate impacts to preference customers if Bonneville acquires resources for the DSIs only to find that they close their operations because of economic conditions beyond the control of Bonneville?**

3. **What are the benefits that the DSIs provide to Bonneville? What is the total value of the subsidies that Bonneville provides for the DSIs? What is the balance between these two equations? How is this relationship likely to change in the next 20 years?**

4. **Why do the DSIs now pay substantially less for power than preference customers?**

Section 7(c)(2) of the Northwest Power Act requires the Administrator to set rates for the DSIs based on the wholesale rates to public entities and the margins that the public entities include in their industrial rates.

We note that the last GAO report which examined Bonneville's relationship with the DSIs, "The Impacts and Implication of the Pacific Northwest Power Bill (EMD-79-105, dated September 4, 1979), predicted that DSI rates would be significantly higher than preference rates. Yet the exact opposite has occurred. Why?

5. **The Northwest Power Act requires the Administrator to "adjust" the value of DSI reserves. Why, then, did Bonneville "freeze" critical components of the reserve methodology for a period of years? How should Bonneville evaluate DSI reserves in coming years, and what alternative mechanisms would protect the ratepayers?**

We also note that the GAO report, cited above, called on Bonneville to conduct a thorough analysis of the alternative ways of providing reserves.

To the best of our knowledge, Bonneville never did the study. We believe such a study would still be valuable, and we encourage the Task Force to see that it is done.

RECOMMENDATIONS

To deal with the variety of issues described above, we offer the following recommendations:

1. The BPA Task Force should request that Bonneville discontinue the variable industrial rate when it expires in 1996. The Task Force should take steps to require that Bonneville adjust the value of DSI reserves to accurately reflect current conditions.

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Each of these points is discussed in more detail in the supplemental text on the following pages. We have not attempted to answer all of your questions to us, but instead have tried to focus on those questions that deal with DSI issues and their impacts on the region's public utilities.

That concludes my oral testimony. I would be pleased to answer questions about these issues.

Thank you for inviting us to testify.

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IT PAYS TO OWN THE UTILITY THAT SERVES YOU

TESTIMONY OF MR. KERMIT W. SCARBOROUGH
Chairman
Canby Utility Board

Submitted to:

THE COMMITTEE ON NATURAL RESOURCES BPA TASK FORCE
September 25, 1993
Eugene, Oregon

TABLE OF CONTENTS
Testimony of Kermit W. Scarborough

Mr. Chairman and Members of the BPA Task Force:

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That concludes my oral testimony. I would be pleased to answer questions about these issues.

Thank you for inviting us to testify.

SUPPLEMENTAL TESTIMONY

QUESTION 1: Competitiveness

How important is it for Bonneville to become more competitive and what principles should guide Bonneville in this effort?

We believe it is very important for Bonneville to become more competitive -- if becoming competitive means keeping electric rates low and supplying energy as efficiently as possible.

Canby has no generating capacity of its own. When Bonneville raises its wholesale rates, we must raise our retail rates. Our customers -- everyone one of them, from the smallest household to the largest company -- feels the impact.

Unfortunately, Bonneville's "competitiveness project," as it is called, has to date consisted of mushy promises and self-laudatory rhetoric.

Bonneville talks about "reinventing itself," as if it could transform itself and shed its complex and often conflicting statutory mandates. We find it significant that Bonneville's draft strategic business objectives, published recently, made no reference to the Northwest Power Act, the Preference Act or any other federal statute.

We suggest therefore that one of the principles that should guide Bonneville in becoming more competitive is its legal obligations to its preference customers.

That means looking carefully -- within its statutory obligations -- for ways to become more efficient and responsive to its traditional customers.

But there is another aspect of Bonneville's competitiveness initiative that troubles us: the unwillingness to date of Bonneville to examine critically its relationship with the DSIs.

The DSIs currently receive two types of subsidies or special treatment from Bonneville: 1) the variable industrial (VI) rate, which fluctuates with the price of aluminum; and 2) credits (discounts) on their power bills for providing forced outage and other reserves.

Those subsidies are discussed in more detail below.

QUESTION 5 (First Part): The Variable Industrial Rate

Should the variable industrial rate for the DSIs be eliminated or modified?

We believe Bonneville should never have implemented the rate in the first place or extended it to 1996. Furthermore, we believe Bonneville should be precluded from implementing similar, speculative rates in the future.

The variable industrial rate is available only for aluminum smelters (90 percent of the total DSI load). The higher the price of aluminum, the more the DSIs pay.

The reverse is also true. When the price of aluminum is low, the rate for the smelters drops. And that, as you know, is what has happened for the last two years.

The VI rate is currently 17.9 mills. But that includes a 7.30 mill demand charge (which does not fluctuate). The energy component is the portion that moves up or down with aluminum prices, and it is only 10.6 mills.

Those rates will go up October 1, when the general rate increase takes effect, but even then the VI rates for the aluminum smelters will be significantly below preference rates.

As far as we can tell, the DSI rates will still be lower than smelter rates anywhere in the United States. In fact, they will still be on par with average electric rates for aluminum smelters in the world (excluding Russia and China).*

At the time the variable industrial rate was adopted in 1986, Bonneville had a substantial surplus and the rate had some justification: to encourage the DSIs to stay in production and to provide some sort of rate stability to the companies. Bonneville feared that low aluminum prices would drive the DSIs out of business, thus creating even more of a surplus and exacerbating Bonneville's revenue problems.

But when the VI rate was renewed in 1991 for another three years, Bonneville was facing a pending power deficit -- the entire dynamics of the regional power supply picture had changed. Bonneville extended the rate anyway.**

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* See brief discussion of comparative prices in cross examination of DSI witness Donald Schoenbeck in Bonneville rate case, May 20, 1993, at page 1427. Mr. Schoenbeck noted that the 1992 worldwide price of electricity for smelters was about 21.8 mills, excluding China and Russia. He was relying on a study performed by CRU, a London firm.

** The rate had originally been adopted for seven years and was scheduled to expire on June 30, 1993. The 1991 decision to extend the VI rate for three years went into effect on July 1, 1993. The rate now expires June 30, 1996.

Furthermore, the price of aluminum, which had jumped to about $1.30 per pound in 1988, was on the decline. In January 1991, when the Administrator formally extended the VI rate, the price of aluminum was about 70 cents. (This information comes from Bonneville and reflects U.S. transaction prices for those dates.)

Table 1 below compares the revenues generated by the VI rate with the estimated revenue from the standard industrial power (IP) rate (what the smelters would normally have paid).

Information in the table was obtained from Bonneville's Division of Contracts and Rates. It contains data for a seven-year period ending June 30, 1993, when the VI rate would have expired had the Administrator not renewed it.

TABLE 1
Revenues Generated by the VI Rate
Aluminum Smelters Only
(In millions)

Year	VI Rate Revenue Actual*	Estimated Revenue (Standard IP Rate)	Difference
FY 1986	$ 56.4	$ 62.8	$ -6.4
FY 1987	360.6	422.0	-61.4
FY 1988	671.9	542.4	129.5
FY 1989	695.6	555.6	140.0
FY 1990	559.7	568.2	-8.5
FY 1991	566.0	577.2	-11.2
FY 1992	392.2	518.5	-126.3
FY 1993**	253.9	322.0	-68.1
TOTAL	$3,556.3	$3,568.7	$-12.4

* Includes energy and demand (capacity) charges. Only the energy charge fluctuates; the demand charge is fixed.

** Includes three quarters of FY 93, ending June 30,1993. Because the price of aluminum has remained at the "floor," the difference between the two rates has continued.

It is important to note that Bonneville made more money in fiscal years 1988 and 1989 from the VI rate than it would have under the standard industrial power rate.

But aluminum prices dropped, thus lowering the VI rate and Bonneville's revenues. Had the VI rate not been extended, it would have expired on June 30, 1993, and Bonneville would have come close to breaking even from the entire seven-year period. In total, it would have received only $12.4 million less under the VI rate than under the IP rate.

But the decision to extend the rate will likely cost ratepayers several hundred million dollars. The reason is that prices hit the floor on August 1991, and have remained there since then. The U.S. transaction price is now 55.5 cents (August 1993).

What caused the dramatic drop in aluminum prices? One of the reasons was the Russian Government's decision to sell large quantities of aluminum to generate cash, which flooded the market. The sluggish world economy, particularly in automobile manufacturing, also dampened demand and forced smelters in the United States and elsewhere to reduce the price they could get for their product.

Market prices have remain depressed. They are now lower than any time in the last 40 years (in real dollars). Although the companies believe that the long-term fundamentals of their industry are good, the prospects for a rebound in the near future are poor. Most industry analysts are not optimistic that aluminum prices will increase significantly in the next two or three years.

Bonneville continues to lose about $32 million a quarter from the VI rate, compared to what it would have received from the companies under the standard industrial firm power rate. And that's where things stand now.

Fortunately, the Administrator has indicated he does not wish to extend the variable industrial rate when it expires in 1996, but it is not clear from his public comments whether he means to discontinue any type of special treatment for the smelters or whether some other form of subsidy will take the place of the variable rate.

As for the value of the reserves -- the second form of subsidy -- he has said nothing, and that is a pity, because the way that Bonneville compensates the DSIs for reserves is flawed.

QUESTION 5 (Second Part): The Value of Reserves Analysis

As part of Question 5, you also asked about Bonneville's Value of Reserve (VOR) analysis.

The VOR does not apply to the first quartile, as explained below. The second quartile, however, provides both forced outage and plant delay reserves. Forced outage reserves are clearly the most important of the two types.

It is difficult to break out the precise value of the second quartile. But we can state that the plant delay reserve section in the existing DSI power sales contract is so cumbersome that Bonneville believes it has little value.

This area is complex and involves some recent rate history. Let me begin with some background information.

The DSI load is separated into quarters (quartiles). The top (first) quartile is nonfirm, and Bonneville can interrupt service at any time and for any reason.

The top quartile does not provide reserves for Bonneville because it can be interrupted. Put another way, only firm DSI load provides reserves.

The remaining three quartiles of DSI load are considered firm. But unlike typical utility firm load, the DSI firm load can be restricted by Bonneville under certain conditions.

These restriction rights allow Bonneville to curtail service to the DSIs, to shed load. It is the creation of these rights which allows Bonneville to treat portions of the DSI load as "reserves."

Every utility needs reserves to provide service for its firm loads when a power plant malfunctions or a transmission line goes down. Typically, a utility provides this reserve by acquiring standby generation.

The other way to achieve a similar level of protection is by shedding load, and that is what Bonneville's contract with the DSIs allows it to do.

The most valuable reserve is "forced outage," which covers plant malfunctions, but Bonneville has also contracted for and pays for plant delay and system stability reserves. It pays for these services by giving the DSIs a discount on their power bill.

It is important to note that only two of the DSI quartiles provide forced outage reserves: the second and third quartiles.

The first (top) quartile provides no forced outage reserves (or any other reserves, for that matter) because it is not firm. The fourth (bottom) quartile provides no forced outage reserve because Bonneville can only restrict it for 15 minutes or less -- too short a time period to be of value.

In other words, it is the middle quartiles that can be restricted for sufficient lengths to qualify as forced outage reserves; Bonneville can shed those quartiles if a plant has a sudden malfunction.

If this arrangement were executed correctly, it could indeed be very efficient for Bonneville's ratepayers.

I do not question the underlying notion that the DSIs can provide reserves in certain circumstances, and that Bonneville should pay a fair market price for these services.

Our problem is that Bonneville pays too much for these reserves, that its methodology is locked into place until 1996 and that Bonneville has shown no inclination to change the methodology -- or even to acknowledge that it is out of date.

The best way to illustrate the problem is to start with Bonneville's May 1985 Value of Reserve (VOR) analysis, which was completed as part of the rate case. The VOR is included in **Attachment A** to this testimony.

The VOR is the only analysis Bonneville has completed on DSI reserves. It establishes three types of reserves: forced outage (described above); plant delay; and system stability.

Of the three, forced outage reserves are clearly the most important, and Bonneville estimated this restriction right was worth about $88.9 million in 1985. The other types of reserves are comparatively small, and they brought the total to approximately $90.3 million. To this figure was added the cost to the DSIs of a restriction. The total amount was then divided by half, and the DSIs's portion was then given as a discount on DSI bills (pro rata for each company).

In 1985, the DSI annual discount for all types of reserves was about $46 million. That amount was escalated for inflation, and it is now worth about $59 million in fiscal year 1994.

In the normal course of ratemaking, the VOR would have been revised during general rate cases (typically every two years). But the 1985 proceeding that established the VOR and a related issue, the industrial margin, were quite contentious, and Bonneville, with support from the DSIs, decided to "lock in" the methodology for calculating the VOR.

This methodology was known as the IP-PF Rate Link and it was adopted in accordance with Bonneville's traditional ratemaking procedures. The Link, first adopted in 1987 for a four-year period, was extended in 1991. It now expires June 30, 1996, at the same time as the VI rate.*

There are, however, two components of the IP-PF Rate Link which are now out of date. They affect how the discounts for forced outage reserve are calculated.

The first, out-of-date component is the amount of forced outage reserves needed by Bonneville. The VOR assumed 1,288 megawatts. The current Pacific Northwest Loads and Resources Study (The White Book), published in January 1993, suggested a lower amount, between 600 and 700 megawatts. Bonneville's own witnesses in the 1993 rate case suggested that a 600-800 megawatt range was realistic for what Bonneville needed from capacity (forced outage) reserves.

The second, out-of-date component is the interest rate attributed to the "proxy" gas turbine. In the VOR, Bonneville estimated the value of the forced outage reserves by computing how much it would cost to acquire the output from a standby plant -- in this case, a combined cycle gas plant.

Because Bonneville cannot build and own its own resources, it assumed that a utility or private developer would build and finance the plants needed for the forced outage reserve.

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* See Administrators' Record of Decision, 1986 IP-PF Rate Link Proposal, adopted March 20, 1987 (IP-PF-86-A-02), and Administrator's Record of Decision, 1990 IP-PF Rate Link Extension, adopted November 19, 1990 (IP-PF-90-A-03).

The interest rate on the plant was set at 14 percent because that was the going interest rate in 1981, when the power sales contracts were signed and when, in the absence of the DSIs, Bonneville would have had to acquire this resource.

In the normal course of doing business, Bonneville routinely requires developers to refinance and pass the savings from lower interest rates on to Bonneville. (See the treatment of this issue in Bonneville's billing credits policy, where it requires a developer to refinance and pass the savings on to Bonneville.*)

Assume, for example, that Bonneville had acquired 600 megawatts of gas-fired resources at 14 percent. Its standard contractual agreement would allow it to require the developer to refinance and pass the difference on to Bonneville and its customers.

The IP-PF Rate Link, however, locked in both the 1,288 megawatt figure for the amount of forced outage reserves and the 14 percent interest figure.

That means the DSIs continue to receive a discount for a significant amount of reserves that Bonneville does not need and which are calculated at an interest rate substantially in excess of current rates.

The revenue impact is significant, as **Table** 2 on page 23 shows.

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* See BPA Billing Credits Policy, adopted August 30, 1984, section 9(i), on the Administrator's Right to Request Refinancing and Improvement of Billing Credit Resource, and BPA Billing Credits Policy, adopted January 29, 1993, section 7(e) on the same subject.

The table, which was filed as testimony in the 1993 Bonneville rate case, was sponsored by the Northwest Conservation Act Coalition (NCAC) and is reprinted here with that organization's permission.

Canby submitted a comment letter to Bonneville regarding the value of DSI reserves. The letter called attention to the importance of this testimony. The Canby letter is also included in **Attachment A** of this testimony.

The NCAC testimony showed that the annual discount for the DSIs is between $15 and $41 million above what it ought to be if Bonneville could adjust the VOR to reflect current market realities.

In the table, the "Bonneville proposal" refers to the status quo -- it assumed nothing would change in the next two years (and the IP-PF Rate Link would not be opened up for amendment).

Scenario 1 assumed the current level of DSI reserves. The interest rate, however, has been adjusted to reflect two current market conditions: 1a assumes private developer financing (9%); 1b assumes municipal financing (6.5%).

Scenario 2 adjusted the value of DSI forced outage reserves from 1,288 megawatts to 800 megawatts. The interest rate remains at 14 percent.

Scenario 3 adjusted the value of DSI forced outage reserves from 1,288 megawatts to 600 megawatts. The interest rate remains at 14 percent.

Scenario 4 adjusted the value of DSI forced outage reserves from 1,288 megawatts to 800 megawatts and adjusts the interest rate to reflect current market conditions. Scenario 4a assumes a 9 percent interest rate. Scenario 4b assumes a 6.5 percent interest rate.

Scenario 5 adjusted the value of DSI forced outage reserves from 1,288 megawatts to 600 megawatts and adjusts the interest rate to reflect current market conditions. Scenario 5a assumes a 9 percent interest rate. Scenario 5b assumes a 6.5 percent interest rate.

Note that Scenarios 2 and 4 both assumed an 800-megawatt forced outage reserve, the high end of the range identified by the Bonneville witnesses in the rate case. Scenarios 3 and 5 both assume a 600-megawatt forced outage reserve, based on the lower figure in the 1992 Loads and Resources Study.

TABLE 2
Adjusting the Value of DSI Forced Outage Reserves
Range of Likely Dollar Impacts

	Quantity of Reserves (MW)	Interest Rate	Impact in FY '94-'95*
Scenario 1a:	1,288	9.0%	$15,014,721
1b:	1,288	6.5	21,827,039
Scenario 2:	800	14.0	21,928,658
Scenario 3:	600	14.0	30,915,994
Scenario 4a:	800	9.0	31,254,069
4b:	800	6.5	35,485,550
Scenario 5a:	600	9.0	37,910,053
5b:	600	6.5	41,083,663

* Average annual impact in these years.

The impact column shows the range of final adjustments that would be made to the annual DSI credit (discount). The larger the number, the more the credit would be reduced.

The adjustments would therefore produce a range of likely impacts between $15 (Scenario 1a) and $41 million (Scenario 5b) in higher DSI revenue and commensurate decreases in priority firm customer revenues.

The hearing officer in the Bonneville case disallowed the NCAC testimony on the grounds that the IP-PF Rate Link precluded reconsideration of the components of the Link until 1996, and that Bonneville had given no notice to the parties (including the DSIs) that the IP-PF Rate Link would be reexamined in the 1993 proceeding.

Thus, the issue was dismissed on procedural, legal grounds. As a result, there was no substantive revaluation of DSI reserves in the 1993 rate case.

We raise it here -- in the context of Congressional testimony -- because we want to call your attention to the large amounts of money at stake and the specific legal requirements in Section 7(c)(3) of the Northwest Power Act that state that the Administrator "shall adjust" the value of DSI reserves in its rates.

We submit that freezing these variables is fundamentally at odds with the notion of adjusting the values and keeping them up to date.

QUESTION 10: Power Sales Contracts

How should the new power sales contracts differ from the current ones?

The new power sales contracts with the DSIs should look radically different from the old ones, but that is not likely to happen without Congressional prodding.

The reason is that Bonneville is currently negotiating with the DSIs as if they were long-term, firm power customers of Bonneville. The Northwest Act does not grant them such a preferred status.

Bonneville needs to put other options on the table for examination in the power sales contract process.

Canby has corresponded with Bonneville about this subject, and those letters are contained in Attachment B.

Please note that Bonneville seems to believe that Section 12 of the existing contracts and a 1981 cover letter -- transmittal correspondence -- obligate them to write firm power, follow-on contracts with the DSIs.

We invite your review of these documents and request that legal counsel for the Committee on Natural Resources assess these documents and determine whether Bonneville is indeed obligated by the existing contracts and a 1981 cover letter to offer long-term, firm power agreements in perpetuity to the DSIs.

On the question of what the DSI contracts should contain, we offer the following comments:

1. **Bonneville should consider offering a range of contract terms (a menu approach) for the DSIs, thus allowing them to choose terms that are best suited toward them.**

Among the items on the "menu" should be contract length (e.g., 5-year, 8-year, 12-year or 20-years). Bonneville should consider imposing some sort of penalty, similar to a "take or pay" obligation, to discourage a DSI from requesting 20-year service if the plant is likely to be in operation for only 5 years.

The purpose behind such a provision is to protect Bonneville from acquiring expensive new resources for the DSIs only to find that the companies cannot sustain operations in the Northwest for economic reasons.

If that were to happen, Bonneville may have to sell the power on the surplus market, a decision which will almost surely create revenue problems and cause preference utilities, such as Canby, to pay more in wholesale power rates.

2. **Investigate the costs and benefits to Bonneville of increased interruptibility for the DSIs.**

At present, only one quartile (the first/top quartile) is interruptible; the other three quartiles are considered firm. Before offering contracts to the DSIs, Bonneville should consider making one or more quartiles interruptible, thus increasing the amount of interruptible service from 25 percent to 50 or 75 percent.

Bonneville should begin the process now of analyzing the fiscal and environmental impacts of such a decision. These types of studies take time; if the draft environmental impact statement (EIS) on the contracts is to be finished by 1994, as Bonneville plans, the studies ought to be begun promptly.

The interruptibility analyses are important because we believe that Bonneville has considerable legal discretion regarding the terms and conditions of future DSI contracts.

The DSIs are treated differently under the Northwest Power Act than utilities. Section 5(b)(1) requires the Administrator to offer long-term contracts to public entities and investor-owned utilities "whenever requested" by those utilities.

Section 5(d)(1)(A), in contrast, states that the Administrator "is authorized" to offer contracts to the DSIs.

Section 5(d)(1)(B) requires the Administrator to offer initial long-term agreement, but the Act is silent about subsequent contracts.

Nor do the existing contracts with the DSIs require Bonneville to offer subsequent long-term agreements for firm power.

Section 12 (mid-term review) appears to contemplate some sort of ongoing relationship between the two parties, but the section clearly states that Bonneville "shall not be obligated" to grant a request for a follow-on contract simply because a DSI gives notice that it wants such an agreement.

In sum, the interruptibility analysis which we request is based on the Bonneville Administrator having significant legal discretion to structure DSI contracts.

He is not obligated to offer contracts to the DSIs that look like the current agreements; the status quo is not mandated in either the Act or the existing contracts.

3. **Examine the costs and benefits to Bonneville of selling the DSIs firm power only in summer and interruptible power in winter. This alternative is a variation from the one described above, but in this alternative, the decision to sell firm or interruptible power would be made on the time of year.**

In a sense, this alternative adds an aspect of "seasonality" to the concept of quartiles: it shifts the DSI load so that it better matches the flow of the Columbia River system and the needs of both Bonneville and its preference customers.

4. **Assess the consequences of putting top (first) quartile service out to bid.**

This option assumes that the new contracts will offer some sort of interruptible service similar to existing, top quartile DSI service.

Instead of assuming that the DSIs are the only entity that can or would use power on this type of restrictive basis, we request that Bonneville examine the consequences of putting interruptible power out to bid. In other words, we request that Bonneville evaluate the legal, financial and operational consequences of letting public and investor-owned utilities and the DSIs bid for the right to buy this power on a long-term contract.

5. **Evaluate the fiscal and operational impacts of giving Bonneville new restriction rights on DSI firm power load.**

At present, DSI firm load can be restricted under a variety of circumstances. (These restriction rights, as they are called in the existing contracts, create "reserves" for Bonneville.) But some restriction rights are so cumbersome and difficult to interpret that they have only marginal value to Bonneville.

One option is to create more expansive restriction rights in the new power sales agreements with the DSIs. These rights could allow Bonneville to curtail DSI service in any number of circumstances, including if the Federal Base System shrinks in size.

This alternative is based on the discretion of the Administrator to sign contracts with the DSIs that are more restrictive than the long-term agreements it signs with public entities and investor-owned utilities.

Under this option, Bonneville could have the right to restrict the DSIs if Hanford Project No. 2 went off line temporarily or permanently and/or if replacement power was not available at a specified price that was spelled out in the contract (and adjusted each year for inflation).

Plant delay reserves (Section 7(d) in the existing DSI contracts) attempt to do this, but the restriction rights are so limited -- and the language itself so awkward -- that Bonneville apparently does not believe these rights have much use.

To avoid similar problems in the future, we therefore request that Bonneville draft clear language in the new contracts that allows it under specified circumstances to restrict the DSIs for plant delay reserves and other types of reserves.

In sum, we encourage the Task Force to prod Bonneville to rethink its relationship with the DSIs, and to shed the notion that it is hamstrung in the way that it approaches the ongoing contract renegotiation process.

1985 FINAL RATE PROPOSAL

WHOLESALE POWER RATE DESIGN STUDY

BPA

BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
May 1985
WP-85-FS-BPA-08

APPENDIX A

VALUE OF RESERVES ANALYSIS

I. Introduction

For most utilities, reserves are provided by generating resources in excess of firm requirements. Usually, this generation is only occasionally needed. However, holding this generation in standby imposes costs on utilities. In the Pacific Northwest, BPA's firm power sales contracts with the direct-service industrial (DSI) customers provide the Federal system with reserves through BPA's ability to restrict or interrupt portions of DSI load, subject to the conditions specified in DSI contracts. Having these restriction rights allows BPA to sell, on a firm basis, energy and capacity that otherwise would be idle to provide reserves. Thus, reserves provided through BPA's restriction rights result in a more efficient use of resources. This discussion describes the analysis that measures the benefits to BPA resulting from BPA's rights to restrict the industrial load.

The Federal system reserves provided by the DSI restriction rights are separated into three parts: forced outage reserves, stability reserves and plant delay reserves. This separation follows the language of section 7 of the DSI power sales contracts executed after December 5, 1980. Forced outage reserves maintain the operating integrity of the Federal system through BPA's ability to restrict the DSI load. Stability reserves prevent regional and interregional instability resulting from underfrequency on the electrical grid

through restricting the DSI load. Plant delay reserves protect the reliability of the system against construction delay and poor performance of new and existing plants through second quartile restriction rights.

To avoid double counting reserves, the quartiles were categorized based on the reserves they predominantly provide. Since BPA does not plan or acquire resources to serve the first quartile under the terms of the power sales contract, the first quartile offers only operating and stability reserves. The interruptibility of the DSI first quartile is recognized in the character of service adjustment of the 7(c)(2) margin study. The second, third, and fourth quartiles provide capacity for both stability and forced outage reserves. However, since the fourth quartile can only be restricted for 15 minutes at any one time, this quartile was not assigned a value for forced outage reserves. Thus, only the capacity associated with the second and third quartiles was valued for forced outage reserves, whereas the capacity associated with the fourth quartile was assigned a value for stability reserves. Since the second quartile of DSI load may be restricted for plant delay reserves, the value for plant delay reserves is based on the energy associated with the second quartile. The reserves provided through BPA's restriction rights are valued according to expected use in conjunction with the provisions contained in the power sales contracts. Thus, a determination is needed of the reserve level in the test year and the amount of reserves provided through the restriction rights on the DSI load.

The organization of this discussion follows the steps used in valuing the reserves. First, the total required level of Federal system reserves for

the test year is determined. Then the expected use of each category of the Federal system reserve requirement is determined. These categories, forced outage and plant delay reserves, are then analyzed in conjunction with the amount of reserves provided by the restriction rights to determine if the reserves provided by BPA's ability to restrict the industrial load can meet the reserve requirements. And finally, each reserve category is separately valued at the cost to BPA of providing the reserve through an alternative means.

II. Determination of the Federal Reserve Requirement

The Federal system capacity reserve requirements for the value of reserves analysis are based on the loads and resources used in BPA's Cost of Service Analysis. This information is the most current available, and incorporates in the value of reserves analysis all assumptions and studies used in support of the 1985 wholesale power and transmission rate filing. For the current rate filing, reserves are based entirely on resources in operation during the test year (FY 1987). Required reserves are calculated at five percent of hydro resources and 15 percent of thermal resources. The total Federal reserve requirement for FY 1987 varies by month from a low of 1016 megawatts in May to a high of 1288 megawatts in December.

For the 1982 wholesale power rate filing, it was assumed that 1880 megawatts of combustion turbines were installed to meet reserve requirements. As the reserve requirement for FY 1987 is less than the

capacity of those installed facilities, no additional plant is needed; the existing assumed facilities will cover the reserve requirement for FY 1987.

III. Expected Use of DSI Restriction Rights

A. Forced Outage Reserves

Hourly output from the Pacific Northwest System Analysis Model (SAM) is used to determine the probability and amount of forced outages covered by BPA's restriction rights in the FY 1987 test year. SAM models the economic operation of Pacific Northwest resources, hydro and thermal. Since SAM performs a Monte Carlo simulation, the user has the option of simulating random water years, random thermal resource arrival and performance, and loads of constant standard deviation centered on a given load forecast. The results of the studies showed no expected forced outages over the seven years of the planning horizon, basically due to the forecasted surplus.

B. Stability Reserves

Currently, no analysis of expected use is performed for stability reserves.

C. Plant Delay Reserves

The SAM is used to determine the probability of expected outages due to delay of a generating resource from the planned initial date of

commercial operation or due to unexpected poor performance. For each simulation and each period within a year, SAM identifies loads that will be served and resources accordingly operated. The priority of serving load in SAM is: (1) firm load; (2) the DSIs' first quartile; (3) storage outside the region; and (4) Pacific Southwest markets. The DSIs' lower three quartiles are included in firm load; however, SAM recognizes that these loads can be restricted under certain conditions. Resources are also stacked in a priority determined by cost and operational considerations. The operating point of the system in SAM is where the benefits associated with serving each load block equal the cost of operating the resources. The following assumptions were used in modeling second quartile restriction rights.

1. In each of the 7 years 75 percent of the surplus firm power is sold to the Pacific Southwest.

2. Due to the Water Budget, Firm Energy Load Carrying Capabilities (FELCC) is reduced by 500 average megawatts.

3. For purposes of calculating a value for plant delay reserves, only Federal generating plants are considered in this analysis.

4. A 27 month delay in the construction schedule for WNP-1 and WNP-3 is assumed for the value of reserves analysis. The planned initial operating date for WNP-1 is September 1993, and March 1992 for WNP-3.

5. SAM currently does not explicitly model DSI restriction rights for poor performance of existing facilities or delay of conservation resources, because the region is still working on modeling these restriction rights. For purposes of valuing BPA's right to restrict the DSIs' second quartile for poor performance, a portion of the firm load curtailments shown in SAM is assumed to be caused by poor performance of existing Federal thermal plants. To approximate DSI interruption for poor performance, firm load curtailments in each of the seven years in the planning horizon were multiplied by the following ratio:

$$\frac{\text{15 percent of Federal thermal resources + 5 percent of Federal hydro resources}}{\text{15 percent of total thermal resources + 5 percent of total hydro resources}}$$

A weighted average of hydro and thermal resources is used to measure poor performance reserves in recognition of the potential poor performance by both resource types.

The expected restriction of the DSIs' second quartile during the 7-year planning horizon due to plant delay and poor performance is summarized in the following table.

TABLE A-1

EXPECTED RESTRICTION
(aMW)

FY	(A) POOR PERFORMANCE	(B) PLANT DELAY	(C) TOTAL
1987	0.514	0.000	0.514
1988	0.385	0.000	0.385
1989	0.774	0.000	0.774
1990	0.823	0.000	0.823
1991	0.662	0.000	0.662
1992	1.433	0.720	2.153
1993	1.712	0.583	2.295

IV. Valuation of Reserves

Absent the DSI restriction rights, BPA would be required to meet its Federal system reserve obligation through alternative means. For the value of reserves analysis, BPA estimates the least cost alternative to the DSI restriction rights.

A. Forced Outage Reserves

If the DSI restriction rights were not available, Federal forced outage reserve requirements probably would be met by the installation of combined cycle combustion turbines. Combined cycle combustion turbines were selected instead of single cycle combustion turbines as the most cost-effective approach to satisfy reserve needs for both capacity and energy. This selection also satisfies the requirement to value both capacity and energy reserves, as directed in the Northwest Power Act. To meet the Federal reserve requirement in 1982, BPA assumed 1880 megawatts of

capacity were installed, consisting of three plants each having six 60 megawatt turbines and one 140 megawatt steam plant, plus one plant having four 60 megawatt turbines and one 140 megawatt steam plant (Table A-2, line 4, column C).

The completed plant cost in 1987 dollars was based on the escalated construction costs for Beaver, a regional combined cycle combustion turbine. This cost was then compared to the current estimates of a similar General Electric project. As no significant cost variation existed between the two estimates, the escalated Beaver costs were appropriate for valuing the least cost alternative to the DSI restriction rights. The total cost associated with adding 1880 megawatts to the system through constructing combined cycle combustion turbines was $770 million. The annual investment cost was determined based on a 14 percent interest rate (consistent with the interest rate associated with new BPA investment in the August 1982 Repayment Study) and a 25-year life. The annual investment cost associated with the value of reserves was $112.035 million (Table A-2, line 6, column B). In the value of reserves analysis, a nominal carrying charge is used and thus the annual investment cost of the alternative to the DSI restriction rights simulates BPA's repayment obligations associated with a particular project. The annual investment cost in the test year is identical to that in FY 1982.

Operation and maintenance cost associated with the plant for the test year is $17.653 million (see Table A-2, line 7, column B). These costs are incurred even if the unit is not running, and are added to the annual

investment cost, resulting in a total annualized capital and maintenance cost of $129.688 million (Table A-2, line 8, column C). However, this annual cost overstates the benefits derived from the DSI restriction rights. In FY 1987, the amount of reserves the DSIs can provide through restriction of the second and third quartiles is greater than the reserves required. The investment cost is prorated based on the amount of reserves required in the test year to the amount of generation installed. Thus, the cost to provide forced outage reserves in lieu of the DSI restriction rights is $88.850 million (Table A-2, line 10, column C).

The valuation for forced outage reserves also includes the operating costs associated with running the combined cycle combustion turbine during the time that the DSIs would have been restricted. The results of SAM show no expected restrictions of the DSIs for forced outages during the test year. Thus, no fuel costs or operating costs associated with running the combustion turbine for forced outages are included in this analysis.

B. Stability Reserves

After consideration of several proposed alternatives, BPA determined in FY 1982 that a load tripping scheme was the least cost alternative to the DSI restriction rights for providing stability reserves. This alternative conforms with both the BPA Reliability Criteria for System Planning and the Western System Coordinating Council Reliability Criteria for

System Design. The load tripping scheme isolates portions of the system and rotates the outages among areas to ensure equal exposure by all customers.

Table A-3 shows the methodology for determining the value of stability reserves. The total investment cost for installing a system-wide load tripping scheme is $3.8 million (Table A-3, line 9, column C). The annual investment cost, $0.729 million (Table A-3, line 11, column C), is based on a 14 percent interest rate and a 10-year life. A 10-year life was chosen to annualize the total investment because the need for a load tripping scheme will substantially change after 10 years due to technological change. Annual maintenance costs are $0.047 million per year (Table A-3, line 16, column C). Thus, the total annual cost associated with installation of an alternative load tripping scheme is $0.776 million (Table A-3, line 17, column C).

C. Plant Delay Reserves

For valuing plant delay reserves, BPA assumed the combined cycle combustion turbine would be operated to meet outages. The costs associated with running the turbine include fuel and variable operation and maintenance costs. These costs were escalated to reflect the costs in the year in which the restriction is expected to occur. In Table A-4 these costs (Columns C and E) are multiplied by the expected megawatts (Column B), then summed to calculate a total running cost (Column G). These total costs are discounted and summed to derive the total value of plant delay reserves over the 7-year

TABLE A-2
FORCED OUTAGE RESERVES

Line No.	(A)	(B)	(C)
1	Capacity Installed (MW)		
2	Three 500 MW Plants	1500	
3	One 380 MW Plant	380	
4	Total		1880
5	Annual Costs ($000)		
6	Annual Investment Costs	112035	
7	Fixed O & M Costs	17653	
8	Total Fixed Costs		129688
9	Federal Reserve Requirement	1288	
10	Annual Fixed Costs Associated with the Value of Reserves ($000)		88850

NOTES:

Line 6: Based on escalated Beaver costs of $200 million per 500 MW plant and $170 million per 380 MW plant. Assumes a 14 percent interest rate based on 1982 Final Repayment Study and 25 year life.

Line 7: O & M costs from PNUCC Database, "Thermal Resources", December, 1982, with costs in 1981 dollars. $6.60 KW/year in OY 1981 dollars escalated to $9.39 KW/year FY 1987, using DRI O&M factors, MCA, page 12, column C.

($9.39) (500 MW) (3 plants) = $14,085 annual O & M cost.
($9.39) (380 MW) (1 plant) = 3,568 annual O & M cost.
Total fixed O & M costs = $17,653.

Line 9: Source, Rate Analysis Model,WP-85-FS-BPA-05, Capacity Resources, page 89.

Line 10: Line 8 times line 9/line 4.

planning horizon (Column J). The annual cost associated with plant delay reserves is $0.664 million.

D. Summary

The value of reserves provided by the DSI restriction rights is:

Forced Outage Reserves	$88,850,000
Stability Reserves	776,000
Plant Delay Reserves	664,000
Total	$90,290,000

TABLE A-3
STABILITY RESERVES VALUATION

Line No.	(A)	(B)	(C)
1	Number of Trip Channels Installed		
2	BPA Stations	43	
3	Foreign Stations	13	
4	Total		56
5	Total Investment Cost ($000)		
6	BPA Stations	903	
7	Foreign Stations	1911	
8	Total	2814	
9	Adjusted total to cover entire system		3800
10	Annual Cost ($000)		
11	Annual Investment Cost		729
12	Annual Maintenance Cost		
13	BPA Stations	20	
14	Foreign Stations	15	
15	Total	35	
16	Adjusted total to cover entire system		47
17	TOTAL		776

NOTES:

Line 6: Line 2 times $21,000 (total cost per channel. $15,000 microwave equipment, and $6,000 overhead.)

Line 7: Line 3 times $147,000 (total cost per channel. $15,000 microwave equipment, $90,000 UHF radio, and $42,000 overhead.)

Line 9: Line 8 times 1.35, which represents the ratio of Total System Light Load to Isolated Area Light Load (10,500 7,780).

Line 11: Assumes a 14 percent interest rate based on 1982 Final Repayment Study and 10 year life.

Line 12: Maintenance costs from the Office of Engineering and Construction, System Studies Section, BPA.

Line 13: Microwave facility cost, $380, CY 1984. Escalated to $454 FY 1987 using DRI GNP Implicit factors, MCA, page 12, col. B. $454 times 43 channels = $19,522.

Line 14: Microwave facility cost, $380, CY 1984. Escalated to $454 FY 1987 using DRI GNP Implicit factors, MCA, page 12, col. B. $454 times 13 channels = $5,902.
UHF facility cost, $580, CY 1984. Escalated to $692 FY 1987, using DRI GNP Implicit factors, MCA, page 12, col. B. $692 times 13 = $8,996.
Total foreign stations: $5,902 + $8,996 = $14,898.

Line 16: Line 15 times 1.35. (see note for line 9).

TABLE A-4
VALUATION OF PLANT DELAY

Line No.	(A) Years	(B) Average Restriction (MW)	(C) Fuel Costs (mills/KWH)	(D) Total Fuel Costs ($)	(E) O & M Costs (mills/KWH)	(F) Total O & M Costs ($)	(G) Total Costs ($)	(H) FY Discount Rate Percent	(I) Discount Factor	(J) Discounted Total Cost ($)
1	FY 1987	0.514	48.00	216076	2.14	9633	225709	11.76	1.000	225709
2	FY 1988	0.385	51.17	172953	2.28	7707	180660	11.48	0.895	161691
3	FY 1989	0.774	55.97	379589	2.44	16549	396138	11.09	0.803	318099
4	FY 1990	0.823	61.92	446236	2.62	18881	463117	10.68	0.723	336280
5	FY 1991	0.662	68.93	399661	2.82	16351	416012	10.44	0.653	271656
6	FY 1992	2.153	76.46	1445862	3.02	57105	1502968	10.36	0.591	888254
7	FY 1993	2.295	83.90	1686490	3.24	65125	1751615	10.27	0.536	938866
8	TOTAL									3140554
9	ANNUAL COST ($)								0.2113	663599 a

NOTES:

Column B: See table A.4-2, Second Quartile Restrictions, WPRDS Documentation.

Column C: See table A.4-1, Escalated Costs for Plant Delay Valuation, WPRDS Documentation.

Column D: Column B times column C times hours in year.

Column E: See table, Escalated Costs for Plant Delay Valuation.

Column F: Column B times column E times hours in year.

Column G: Column D plus column F.

Column H: Source, Branch of Revenue Requirements & Modeling, BPA.

Column I: Calculated from column H, using the following formula: $1/[(1+N_1)(1+N_2)\ldots(1+N_n)]$

Column J: Column G times column I.

a: Derivation of average nominal discount rate and capital recoveror for plant delay, 1987-1993:1993:
$(1.1176)(1.1148)(1.1109)(1.1068)(1.01.1036)(1.1027) = 2.059$ $\quad 2.059^{1/7} = 1.1087$

Carrying charge based on 7 years = .2113.
Formula for calculation:

$$\frac{i(1+i)^n}{(1+i)^n-1}$$

where i = .1087 and n=7.

TABLE A-5
PRODUCTION COST OF DSI OUTAGE

Line No.	(A) Years	(B) Average Restriction (AVG MW)	(C) Production Costs (mills/KWH)	(D) Total Production Costs ($)	(E) FY Discount Rate Percent	(F) Discount Factor	(G) Discounted Total Costs
1	FY 1987	0.514	125	562697	10.83	1.000	562697
2	FY 1988	0.385	141	477441	10.54	0.902	430651
3	FY 1989	0.774	147	996991	10.09	0.816	813545
4	FY 1990	0.823	145	1046766	9.78	0.741	775654
5	FY 1991	0.662	144	835671	9.80	0.675	564078
6	FY 1992	2.153	148	2789086	9.85	0.615	1715288
7	FY 1993	2.295	168	3366789	9.77	0.560	1885402
8	TOTAL						6747315
9	ANNUAL COST ($)					0.2064 [a]	1392646

NOTES:
Column B: See table A.4-2, Second Quartile Restrictions, WPRDS Documentation.
Column C: See table A.5-1, Escalated DSI Production Costs, WPRDS Documentation.
Column D: Column B times column C times hours in year.
Column E: Source, DRI, US Long-Term Review, Spring, 1984, Table 25 TREND25YR0384.
Column F: Calculated from column E, using the following formula:
1/[(1+N)(1+N). . . (1+N)].
Column G: Column D times column F.

a: Derivation of average nominal discount rate and capital recovery factor for DSI outage costs,
1987 - 1993: (1.1054)(1.1009)(1.0978)(1.0980)(1.0985)(1.0977) (1.1113) = 1.966
1.966 = 1.1014 Carrying charge based on 7 years = .2064

Formula for calculation: i(1+i) /(1+i) -1 where i = .1014 and n = 7

CANBY UTILITY BOARD
154 N.W. FIRST AVENUE - P.O. BOX 1070 - CANBY, OREGON 97013
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FAX (503) 263-8621

IT PAYS TO OWN THE UTILITY THAT SERVES YOU

March 10, 1993

Jo Ann Scott, Manager
Public Involvement Section
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

SUBJECT: Participant Comments
Bonneville Wholesale Power Rate Proceeding
Docket WP-93 and TR-93

Dear Ms. Scott:

The Canby Utility Board, which serves residential, commercial and industrial customers in Canby, Oregon, submits the following participant comments regarding the 1993 Bonneville wholesale power rate proceeding.

We are generally concerned about the size of the proposed rate increase (11.6 percent) for the same reasons that many other Bonneville preference customers are also concerned. I am writing to raise a specific objection to the way that Bonneville values reserves provided by the Direct Service Industrial (DSI) customers.

The value that Bonneville has assigned to DSI reserves -- 2.43 mills, equivalent to $59 million as an annual credit to these industrial customers -- appears to be based on faulty and out-of-date assumptions.

The Canby Utility Board believes Bonneville is under a legal obligation to its customers to revise this number in light of several changing circumstances. At stake is between $15 and $41 million in increased DSI revenue and commensurate decreases in preference revenue.

Bonneville last valued the DSI reserves in 1985, when it conducted its first and only Value of Reserves (VOR) analysis. The VOR was intended to place a value on three types of reserves (forced outage, plant delay and system stability).

These reserves are provided by series of restriction rights in the DSI's 20-year power sales contracts with Bonneville. The restriction rights give Bonneville the right to interrupt the DSIs at certain times and under certain conditions, thus providing reserves for Bonneville that it

normally would have to acquire by acquiring the output of combustion turbines.

The VOR was based on proxy gas turbines -- the alternative source of reserves if Bonneville could not restrict DSI firm power loads.

In 1985, the value of DSI reserves was approximately $90 million, of which $89 million were allocated to forced outage reserves. To this sum was added the projected cost to the DSIs of a Bonneville power restriction. The two items totalled about $92 million. Half of this amount -- $46 million -- was then allocated to the DSIs as an annual credit (discount). This value escalates for inflation, and is now about $59 million.

The VOR, however, is based on two important planning assumptions, both of which now appear to be out of date.

The first is that the DSIs provide 1,288 megawatts of forced outage reserves. That was the case until January 1993, when Bonneville published a new White Book, which showed that it counts on the DSIs for 600 megawatts of forced outage reserves.

Testimony in the current rate proceeding suggested that the actual figure may be slightly higher --between 700 and 800 megawatts -- but even if these figures are adopted as the planning assumption for fiscal years 1994-95, they are considerably lower than the 1,288 figure used in 1985.

Another change that should be made in the VOR is that the gas turbine proxy (the plant that would have been acquired if the DSIs did not provide reserves) is based on a 14 percent interest rate.

A 9 percent figure more accurately reflects today's market if a private entity were to build the turbines, and a 6.5 percent figure us more accurate if a public entity with ability to sell tax-exempt bonds were to finance construction.

Unfortunately, the VOR cannot be modified automatically to reflect either the reduction in forced outage reserves used for planning reserves or the lower interest rate. The reason is that Bonneville "locked in" the essential components of the VOR in 1987. The "lock" was approved as part of the IP-PF rate Link, which was extended in 1990, and now expires in June 1996.

The only was to "unlock" the values in the rate link are in a general rate proceeding, such as the one that Bonneville is currently conducting. Yet Bonneville apparently refuses to do so, saying that its decision in 1990 is final and that the IP-PF Rate Link precludes it from adjusting the value of DSI reserves.

Ms. Jo Ann Scott
March 10, 1993
Page 3

Bonneville's position, in the opinion of the Canby Utility Board, ignores the mandate of section 7(c)(3) of the Pacific Northwest Electric Planning and Conservation Act, which states: "The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers."

We interpret this language strictly, as we believe a court would do: Bonneville needs to adjust the value of reserves to match the current conditions. The changes that we seek are significant, as the two tables in Appendix A of this letter show. (The tables were submitted by the Northwest Conservation Act Coalition as part of its testimony on Bonneville reserve issues.)

We do not ask that the Bonneville open up the entire IP-PF Rate Link for review; we are not asking that you revise all the assumptions and formulas, but rather that you adjust the existing values to account for the changes listed above.

The savings to preference customers, including the Canby Utility Board, will be substantial. We therefore urge Bonneville to undertake this evaluation as soon as possible.

Sincerely,
CANBY UTILITY BOARD

Dirk Borges,
Manager

APPENDIX A

The tables in this appendix and the description of the scenarios were taken from the testimony of D. Seligman, witness for the Northwest Conservation Act Coalition (WP-93-E-NA-1).

TABLE 1
RANGE OF PROPOSED ADJUSTMENTS
VALUE OF RESERVES (VOR)

	MW	Interest Rate	VOR
Bonneville Proposal	1,288	14.0 Percent	2.43 mills
Scenario 1a	1,288	9.0 Percent	1.82
Scenario 1b	1,288	6.5 Percent	1.54
Scenario 2	800	14.0 Percent	1.54
Scenario 3	600	14.0 Percent	1.17
Scenario 4a	800	9.0 Percent	1.16
Scenario 4b	800	6.5 Percent	.99
Scenario 5a	600	9.0 Percent	.89
Scenario 5b	600	6.5 Percent	.76

The Bonneville proposal assumes that the status quo remains in tact for the next two years.

Scenario 1 assumes the current level of DSI reserves. The interest rate, however, has been adjusted to reflect two current market conditions: 1a assumes private developer financing (9%); 1b assumes municipal financing (6.5%).

Scenario 2 adjusts the value of DSI forced outage reserves from 1,288 megawatts to 800 megawatts. The interest rate remains at 14 percent.

Scenario 3 adjusts the value of DSI forced outage reserves from 1,288 megawatts to 600 megawatts. The interest rate remains at 14 percent.

Scenario 4 adjusts the value of DSI forced outage reserves from 1,288 megawatts to 800 megawatts and adjusts the interest rate to reflect current market conditions. Scenario 4a assumes a 9 percent interest rate. Scenario 4b assumes a 6.5 percent interest rate.

Scenario 5 adjusts the value of DSI forced outage reserves from 1,288 megawatts to 600 megawatts and adjusts the interest rate to reflect current market conditions. Scenario 5a assumes a 9 percent interest rate. Scenario 5b assumes a 6.5 percent interest rate.

Note that Scenarios 2 and 4 assume an 800-megawatt forced outage reserve, the high end of the range identified by the Bonneville witnesses. Scenarios 3 and 5 both assume a 600-megawatt forced outage reserve, based on the figure in the 1992 Loads and Resources Study.

TABLE 2
ADJUSTING THE ANNUAL VALUE OF DSI RESERVES
RANGE OF LIKELY DOLLAR IMPACTS

	Quantity of Reserves (MW)	Interest Rate	Impact in FY '94-'95*
Scenario 1a:	1,288	9.0 Percent	$15,014,721
1b:	1,288	6.5 Percent	21,827,039
Scenario 2:	800	14.0 Percent	21,928,658
Scenario 3:	600	14.0 Percent	30,915,994
Scenario 4a:	800	9.0 Percent	31,254,069
4b:	800	6.5 Percent	35,485,550
Scenario 5a:	600	9.0 Percent	37,910,053
5b:	600	6.5 Percent	41,083,663

* Average Annual Impact

The impact column shows the range of final adjustments that would be made to the annual DSI credit (discount). The larger the number, the more the credit would be reduced.

The adjustments would therefore produce a range of likely impacts between $15 (Scenario 1a) and $41 million (Scenario 5b) in higher DSI revenue and commensurate decreases in priority firm customer revenues.

The total value of reserves -- using the current Bonneville assumptions -- is $117,592,140 in FY 1994 and $121,296,300 in FY 1995, according to Table 37 in Bonneville's Documentation for the 7(b)(2) Test Study, page 121. The average is therefore $119,444,220.

To calculate the DSI share of this value, the total is divided by two (to reflect the "share the savings" approach adopted by Bonneville in the 1985 VOR analysis.) Thus, the DSI value of reserves in FY 1994-95 is $59,722,110.

By subtracting the numbers in the table above, it is possible to calculate the adjusted value of reserves, depending on which scenario is adopted.

Reducing the interest rate would lower the value of reserves by $15,014,721 (Scenario 1a) or $21,827,039 (Scenario 1b), depending on what interest rate was used, but assuming that 1,288 megawatts of forced outage reserves were required.

On the other hand, if the amount of reserves were reduced, as proposed in Bonneville's testimony and the 1992 Loads and Resources Study (The White Book), then the effect of the interest rate reduction would be smaller -- it would be computed on 600-800 megawatts rather than 1,288 megawatts.

Scenarios 4 and 5 show the effects of reducing the quantity of DSI forced outage reserve and reducing the interest rate on the turbines.

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IT PAYS TO OWN THE UTILITY THAT SERVES YOU

July 23, 1993

Mr. Randall Hardy, Administrator
Routing: A
Bonneville Power Administration
P. O. Box 3621
Portland, OR 97208

Dear Mr. Hardy:

The Canby Utility Board was pleased to have participated in the June 23 meeting with Walt Pollock and others at Bonneville to discuss DSI Second Quartile restriction rights and related issues.

According to our consultant, Dan Seligman, who participated in the meeting on our behalf, Bonneville stated that Section 12 of the existing DSI power sales contracts requires it to offer new agreements to all DSIs.

Section 12 provides: "If the Purchaser (DSI) desires service from Bonneville beyond the term of this contract, the Purchaser shall request a new power sales contract not later than the end of the 12th Contract Year. Bonneville shall not be obligated to offer the Purchaser a new power sales contract because of any request, but shall promptly proceed to attempt to acquire sufficient resources to enable it to grant such requests." (Emphasis added).

The next sentences go on to describe what happens if, as a result of this request, Bonneville acquires sufficient resources. But the remaining portion of Section 12 is conditional -- it describes what happens if the DSIs request that Bonneville expend funds on their behalf for new resources.

It is difficult for us to understand how a sentence that says Bonneville is not obligated to offer new contracts to the DSIs could be construed to say that Bonneville is obligated.

This is not a matter of legal quibbling on our part. If Bonneville assumes at the outset that it is obligated to offer new agreements to the DSIs, Bonneville compromises its own bargaining power.

Put another way, the DSI load is discretionary after 2001, and it is the DSIs' burden to demonstrate why they should remain direct customers of Bonneville and what they have to offer

CANBY UTILITY BOARD
MR. RANDALL HARDY
JULY 23, 1993
PAGE TWO

the region.

For the preference customers of Bonneville, the issue comes down to 2,800 average megawa of power -- the DSI load which is now allocated to the companies under the existing contract. Some DSIs, as you know, have older plants and may not be in business 15 or 20 years from now. Others certainly will want to stay and sign contracts with Bonneville. If Bonneville ignores its rights under the contracts to all DSIs in 2001, Bonneville ties its own hands and commits itself to a course of action that may run counter to the long-term interests of its other customers.

I understand that Bonneville believes it has a clean slate from which to develop new contract provisions. We concur. But Bonneville also has the discretion not to sign contracts with the DSIs at all.

Whatever fixed obligations are imposed on Bonneville by Section 12, signing long-term power sales contracts with the DSIs is not one of them, as the language in the contract makes clear.

We respectfully ask that you reconsider Bonneville's position regarding Section 12 and treat the DSIs as a discretionary load after 2001.

Sincerely,
CANBY UTILITY BOARD

Kermit Scarborough
Chairman

cc: Mr. Walt Pollock, Assistant Administrator for Power Sales

SECTION 12 OF EXISTING DSI POWER SALES CONTRACTS

§12 If the Purchaser desires service from Bonneville beyond the term of this contract, the Purchaser shall request a new power sales contract not later than the end of the 12th Contract Year. Bonneville shall not be obligated to offer the Purchaser a new power sales contract because of any request, but shall promptly proceed to attempt to acquire sufficient resources to enable it to grant such request. If, as a result of such request, Bonneville acquires resources or makes other expenditures to serve the Purchaser under a new power sales contract and offers to negotiate in good faith a new power sales contract with the Purchaser, the Purchaser shall reimburse Bonneville for all otherwise unrecoverable costs incurred as a result of said acquisitions or other expenditures should the Purchaser fail to sign such contract. Bonneville shall use its best efforts to mitigate such costs.

The 12th Contract Year notice requirement has been extended. The DSIs must provide notice to Bonneville no later than January 1995 if they want service beyond 2001.

Department of Energy
Bonneville Power Administration
PO Box 3621
Portland, Oregon 97208-3621

In reply refer to AP

August 16, 1993 RECEIVED AUG 17 1993

Mr. Kermit Scarborough, Chairman
Canby Utility Board
P.O. Box 1070
Canby, Oregon 97013

Dear Mr. Scarborough:

Randy Hardy has asked me to respond to your letter dated July 23, 1993. In your letter, you asked that Bonneville Power Administration (BPA) "treat the DSIs [Direct Service Industries] as a discretionary load after 2001". I understand, based on your position that the DSI load is discretionary after 2001, you believe it should be "the DSIs' burden to demonstrate why they should remain direct customers of Bonneville and what they have to offer the region." You also asked that we reconsider BPA's position regarding section 12 of the DSI contract, which discusses BPA's obligations with respect to contracts for service following termination of their current power sales contracts (these are commonly referred to as the "follow-on" contracts).

Section 12 provides that if a DSI wants service from BPA beyond the term of the current power sales contract, the DSI must request that service by a specific date (this date was recently extended by BPA). It also provides that "Bonneville shall not be obligated to offer the Purchaser a new power sales contract because of any request, but shall promptly proceed to attempt to acquire sufficient resources to enable it to grant such request." This contract provision obligates Bonneville to attempt to provide service, by making a reasonable and good faith effort to acquire sufficient resources. In view of this contractual obligation, it cannot be said that the DSIs are merely a "discretionary load" after 2001.

The original transmittal letter attached to the DSIs' current power sales contract (copy attached) discusses section 12, and includes the statement that "[w]e hope you will find section 12 of the attached contract responsive to some of the concerns that have been expressed as to Bonneville's recognition of your need for future, as well as immediate, power planning certainty." It also states that "Bonneville's ability to offer any future contracts to its nonpreference customers, including the Industrial Purchasers, is therefore largely dependent upon Bonneville achieving firm load/resource balance while these initial contracts are in effect." This letter corroborates the fact that BPA has an obligation to attempt to provide follow-on services to the DSIs.

Aside from our contractual obligations, BPA thinks it makes good business sense to enter into future commercial arrangements with the DSIs. There are many attractive attributes associated with DSI loads, primarily based on the economies that result from operation of our system to take advantage of light loadhours and nonfirm energy availability to serve a portion of that load. We will continue to work with the DSIs and other customers and interested parties in the power sales contract renegotiation process to explore the issues of future service.

I hope this letter has been helpful to you. If you have additional questions or concerns, please feel free to contact me.

Sincerely,

Walter E. Pollock

Walter E. Pollock
Assistant Administrator for
Power Sales

2 Attachments

DE-MS79-81BP90343

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

In reply refer to: PCI

AUG 27 1981

Mr. B. D. Cocknell
Aluminum Company of America
1501 Alcoa Building
Pittsburgh, PA 15219

Mr. B. D. Cocknell
Northwest Alloys, Inc.
Aluminum Company of America
1501 Alcoa Building
Pittsburgh, PA 15219

Dear Mr. Cocknell:

In response to your request to be offered the power sales contract under the Pacific Northwest Electric Power Planning and Conservation Act, this written offer is sent to you for your consideration.

The enclosed four copies of the initial long-term power sales contracts are the result of the negotiation process just completed. Please note that the Bonneville Power Administrator has already signed this contract. The signed contract constitutes a firm offer as required by the Regional Act. Your Company has one year from the date it receives this offer to accept it by signing and returning the contract to Bonneville.

Bonneville is aware that the Industrial Purchasers do not necessarily agree with Bonneville on the existence or the extent of Bonneville's right to displace all or any of its available resources in a manner that would reduce the availability of power for service to the first quartile of the Industrial Purchasers' load. It is not Bonneville's intent to resolve this disagreement in the attached contract. Rather, as indicated in section 7(c) of the attached contract, Bonneville's displacement actions are to be undertaken only subject to Bonneville's legal rights, legal obligations, and policies concerning displacement. When such policies are developed, the Industrial Purchasers will have the opportunity to participate in the policy development and, if dissatisfied by the result, to contest it. By executing the attached contract, no Industrial Purchaser will waive any right or claim with respect to this issue.

This contract is the initial contract that Bonneville is required to offer each Industrial Purchaser pursuant to sections 5(d)(1)(B) and 5(g) of the Regional Act. As you know, the Act contemplates in section 5(d)(1)(B) additional, future contracts with each existing Industrial Purchaser, but

unlike this initial contract, such future contracts do not have the benefit of the statutorily deemed sufficiency of power available to the Administrator under section 5(g)(7). Bonneville's ability to offer any future contracts to its nonpreference customers, including the Industrial Purchasers, is therefore largely dependent upon Bonneville achieving firm load/resource balance while these intial contracts are in effect. Bonneville is aware that most, if not all, of the Industrial Purchasers are necessarily considering substantial new capital investment at their existing facilities during the period of the initial contracts, and that as a result the useful life of these facilities may be extended well beyond the 20-year term of the initial contracts. We hope you will find section 12 of the attached contract responsive to some of the concerns that have been expressed as to Bonnevilles' recognition of your need for future, as well as immediate, power planning certainty. We would certainly expect future Bonneville officials to recognize this need as well. At the same time, Bonneville's obligation to maintain load/resource balance through the efforts of its Customers and other non-Federal entities, and the goal of achieving load/resource balance in making possible future contracts and a continuing program under the Regional Act, needs to be borne in mind by the Customers as well as by Bonneville.

Bonneville has recently conducted cash flow analyses that indicate that should there be substantial Industrial Purchaser curtailment below sales projected in designing Bonneville's 1981 wholesale power rates, Bonneville would experience severe cash flow difficulties, potentially of such a magnitude as to endanger Bonneville's ability to purchase necessary power. In the contract negotiations all parties recognized that Bonneville needs to minimize cash flow problems, and that consequently a method should be agreed upon for dealing with underrecoveries of costs incurred pursuant to section 5 (c) of the Regional Act at intervals prior to July 1, 1985. Bonneville recognizes that this was not solved during the negotiation of the contract, however, our recent review of potential cash flow problems convinces us that it is imperative to resolve this issue now.

Bonneville intends to resolve this problem in future years through policies of general applicability in its annual rate proceeding. One possible way to deal with the particular cash flow problem resulting from DSI curtailments would be, if a DSI reduced its Operating Demand upon notice prior to the beginning of the Contract Year pursuant to section 5(b)(4) of the new contract, Bonneville could reallocate the cost of exchange resources or reduce the amount of purchases it otherwise might have to make.

We believe that this resolution is consistent with the legal obligations imposed by section 7(b)(3) and section 7(c)(1)(A) of the Regional Act, and does not prejudice the right of any person or entity to present and to have considered any arguments or evidence it may wish to present in Bonneville's rate proceedings conducted pursuant to section 7 of the Regional Act. The following conditions will aid Bonneville's cash flow needs, and do not

establish or alter any ultimate legal obligation of the Industrial Purchasers under the Act for the payment of any particular costs. The firm offer contained in the enclosed contract, therefore, is conditioned upon the following:

> If Bonneville determines after consultation with the Industrial Purchasers that: (1) in any month during the rate period total power sales to all Industrial Purchasers have fallen below 90 percent of the monthly projection of the total Industrial Purchaser load contained in Bonneville's 1981 wholesale power rate filing because of voluntary curtailments by Industrial Purchasers; (2) Bonneville projects significant cash flow problems as a result of such voluntary curtailment; and (3) Bonneville determines that it is unable to mitigate the shortfall in revenues resulting from such curtailments by selling energy made available because of such curtailment, reducing purchases or some other method, then Bonneville shall include in each Industrial Purchaser's next regular power bill the Purchaser's share of the shortfall resulting from such curtailments (less any savings realized by Bonneville's best efforts to mitigate the shortfall) based on the proportion of the Purchaser's projected Operating Demand to the total projected Operating Demands of all Industrial Purchasers executing new DSI Contracts, as contained in Bonneville's letter to your company dated August 14, 1981. This surcharge shall be superseded when Bonneville's wholesale power rates to the Industrial Purchasers provide for recovery of such shortfalls.
>
> Any amount paid by a Purchaser pursuant to this provision shall be credited to the Purchaser's benefit when Bonneville computes the amount that the Purchaser will pay or receive under section 7(b)(3) of the Regional Act.

Bonneville believes that the foregoing "shortfall" provision is necessary to assure operations consistent with sound business principles. The shortfall provisions will not be invoked unless voluntary curtailment is greater than 10 percent and a significant cash flow difficulty arises. Even then, Bonneville will use its best efforts to mitigate any revenue shortfall by selling the curtailed power or displacing any purchases to the extent possible while still meeting Bonneville's contractual obligations.

I regret that this matter has arisen at this late date but we believe that our obligation to recover our costs requires that we condition the offer of the long term contract on this provision, recognizing that in the future, such potential revenue shortfalls will be dealt with in Bonneville's rate proceedings.

Fax Transmittal Memo 7672

To: Mr. Scarborough
Company: Canby Utility Board
Location:
Fax #: 503/263-8621
Telephone #:
Comments:

From: Nicki Stauffer
Company: BPA
Location:
Date: 8/17
Time: 2:15
Fax #:
Telephone #:
Original Disposition: ☐ Destroy ☐ Return ☐ File for records

Page 4 of attachment to Aug. 16 letter.
Sorry for the inconvenience.

4

If your Company finds the provisions of the contract and the above condition acceptable, please have the appropriate officials sign this contract and the copy of this letter and fill in the execution date of the contract on page 2. Please return one copy of each document to Bonneville and keep remaining copies for your files.

Please contact our office if you have any questions.

Sincerely,

/S/ Peter T. Johnson

Administrator

Enclosures

Company Aluminum Company of America

Executed by /S/ R. Arnold Kramer

Title Executive Vice President

Company Northwest Alloys, Inc.

Executed by /S/ J. Reid Clark

Title Vice-President

STATEMENT OF DONALD R. CLAYHOLD

Mr. CLAYHOLD. Thank you, Chairman DeFazio. My name is Don Clayhold, I am the manager of the Benton County Public Utility District with its main office located in Kennewick, Washington. That is in southeast Washington. I appear here on behalf of the Northwest Irrigation Utilities, referred to sometimes as NIU. Benton PUD is a member.

NIU is a utility association. NIU is not an association of irrigators; it is a utility association for utilities that have significant irrigation pumping loads, made up of PUDs and REA cooperatives throughout Washington, Oregon and Idaho. We are all preference customers of BPA; most of us are full-requirements customers of BPA.

A large percentage of the annual power sales of NIU members is to irrigation consumers. The vast majority of irrigation usage in the Northwest occurs during the summer months of June, July and August—and that is important. Virtually no irrigation occurs during the winter, and I will expand on why that is important.

NIU members represent about 90 percent of Bonneville preference customer irrigation load. We have submitted a written statement on this matter. Many of our NIU members, most all of us belong to the other organizations that you have had appear here today, such as PPC, the Public Power Council, Pacific Northwest Generating Company for our co-ops, PNGC, the non-generating utilities, NGU, we belong to that and others. Basically we support the comments and response to the questions that you have sent to these associations.

We are going to focus on the irrigation discount because that is what we are about. That is this association's focus and the reason why NIU exists.

Two points I want to make today. First, this is a unique load—irrigation load. It happens during the summer time, and it goes away in the winter. No other load that we know of does that or has those kind of characteristics. Because of that, it offers benefits to the system; it offers benefits to Bonneville. A large portion of Bonneville's costs are incurred to design a system that is winter peaking. Irrigation loads normally do not add to winter peaking; they take away from the peak somewhat in that they disappear during the winter. It is our belief that, on a cost-allocation basis, there is a justification for rate treatment for irrigation loads.

It is probably unfortunate that the term irrigation discount is used. We would prefer an irrigation rate. Discount implies a subsidy, and in fact in the last rate case, it was argued by some that we must get rid of these subsidies because they burden other ratepayers unfairly. And our point is, and I think a point made by most of the folks here today testifying, that it ought to be cost-based. If it is truly cost-based, then there will be an irrigation rate that reflects a lower rate than the general all-around preference rate which has to support the costs of a winter-peaking system.

The other point that I want to leave you with today is that many of our members of NIU are very rural in nature and upwards of 70 percent of their revenue comes from pumping, irrigation pumping. And if that were to cease to be there, these very rural utilities would be in deep trouble—they probably could not survive. And

perhaps even beyond that and more important is that they represent a number of small communities throughout the rural area that depend on irrigated agriculture, and it is doubtful that they could survive either.

Throughout Bonneville's 50-year history, there has been an irrigation discount rate, based on the fact that it costs less to serve this non-growing—by the way, it is a non-growing—load. In fact, it has declined a little over the years due to conservation. It is an off-peak in terms of seasonal peak, summer load, and it costs less to serve it than it costs to serve BPA's year-around winter peaking loads. By the way, we are talking about a $12 million issue here, so it is not large in terms of Bonneville's financial picture, but it is very large in terms of the utilities that receive this rate.

The basic reason why Bonneville's costs are increasing are the cost of new resources and transmission facilities required to serve growing winter peak loads. Irrigation does not contribute to BPA's winter peak demand. There is no irrigation usage in winter; in fact, it is the summer months of June, July and August. Irrigation is not causing BPA to incur resource acquisition costs to meet winter load. In fact, irrigation is not causing Bonneville to incur resource acquisition costs at all, because it is a non-growing load.

The irrigation load provides benefits to BPA and its customers and complements BPA's winter-peaking system by providing load and revenue in the summer when BPA demand is otherwise at its low point. It is increasingly important as the operation of the federal system is modified to increase summer flows to meet fish and wildlife requirements during the summer months.

The irrigation discount goes back to 1942. From 1942 to roughly 1974, it was based on low-cost and availability of surplus power when Bonneville was in surplus back in those days, during the summer. During this period, Bonneville had enough low-cost hydro to meet year-round needs. There was no need to acquire high-cost thermal until later on and finally during that time the hydro system was expanded to meet load growth. The ability of BPA to meet load growth ended about the 1970s, and at that point, Bonneville introduced a concept in its rate called seasonality. Seasonal rates took account of the fact that the cost of acquiring resources to meet growing winter demand was the principal reason for increasing BPA costs. BPA seasonalized rates by increasing the winter period rates to reflect the higher cost of new resources required to meet winter loads. The idea was that BPA should send a price signal to the customers who were causing BPA to need additional resources. The hope was that this price signal would cause BPA's customers to be more efficient.

The tiered-rates proposal which BPA is now considering or will consider, from what we understand, is based on a similar concept. The idea is that utilities should face higher-cost power for their load growth. Again, it is hoped the price signal will cause growing utilities and their consumers to be more efficient.

The irrigation discount was phased out between 1974 and 1979, as seasonality of rates came into being. In the 1979 rate case, Bonneville said that because of seasonal rates there was no need for an irrigation discount, and in 1979, that was roughly true. And the

seasonality at that time kept roughly the same parity between them.

Since then, that has deteriorated as Bonneville has phased out seasonality over time. It does not make any sense to us to phase out seasonality. We think it is just as true now as it was then.

We think that as Bonneville's river system becomes more inflexible, and we understand it is because of required flows for protection of fish and restoration of fish runs, that a summer load that is unique, like an irrigation load, will offer even more benefits to Bonneville.

Finally, with respect to the Competitiveness Project, we really do not know that much about it yet to take a position other than to say that we agree that Bonneville simply must become more efficient in order to continue to deliver cost-effective products. It is not possible for us to say in advance that we will be pleased with or support each and every proposal that comes out. Nevertheless, it is an important initiative and we are pleased that Bonneville has undertaken this review.

Thank you very much, Mr. Chairman, for the opportunity to comment.

Mr. DEFAZIO. Thank you. Mr. Kittredge.

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

TESTIMONY OF DON CLAYHOLD
ON BEHALF OF
NORTHWEST IRRIGATION UTILITIES
BEFORE THE
UNITED STATES HOUSE OF REPRESENTATIVES
COMMITTEE ON NATURAL RESOURCES BPA TASK FORCE

My name is Don Clayhold. I am the Manager of the Benton County PUD. The Benton County PUD is a Washington municipal utility district headquartered in Kennewick, Washington. The PUD provides retail electric service to consumers in Benton County, Washington. The Benton County PUD is a full requirements preference customer of the Bonneville Power Administration ("BPA"). Approximately 18 to 20 percent of the Benton County PUD's annual power sales are for irrigation usage.

I provide this written testimony on behalf of the Northwest Irrigation Utilities ("NIU"), of which Benton PUD is a member. NIU is a utility association comprised of public utility districts and rural electric cooperatives in Washington, Oregon and Idaho. All NIU members are preference customers of BPA. All NIU members purchase the majority of their power from BPA and most are full requirements customers. A significant percentage of the annual power sales of all NIU members is for irrigation usage within the BPA service area. More than half of the region's irrigation load served with BPA power is served through NIU members. NIU members represent about 90% of BPA's preference customer irrigation load.

NIU appreciates the opportunity to present its views to the Committee. Your letter of August 25, 1993 inviting NIU to testify at this hearing identifies a number of important issues facing BPA. One of those issues, the irrigation discount, is the principal focus of my testimony. However, consistent with your letter, I will refer to other issues mentioned therein as an overall framework for my comments. In particular, I will address the continuing justification for the irrigation discount in light of BPA's top to bottom review of BPA operations, which has come to be known as the "Competitiveness Project".

I. Summary. BPA has had an irrigation discount as part of its general rate schedules for approximately 50 years. Historically, the irrigation discount was based on the low cost and availability of surplus power during the summer irrigation season. Continuation of the irrigation discount, or an equivalent summer only rate, remains justified based on BPA's low cost of service during the "off-peak" summer period, and the system benefits provided by this unique summer only load.

The key fact about BPA's budget is that costs are driven by the obligation to acquire additional resources and transmission capacity to serve BPA's growing winter period loads. This will be increasingly true as the Northwest moves from the power surpluses

of the 1980s into a period of resource acquisition in the 1990s. Increasing constraints on the storage of water due to fish flow requirements adds to the need for additional resources to meet winter demand while causing additional low cost hydropower to be available in the summer.

Irrigation has not and it will not cause BPA to incur additional resource costs. Irrigation is a non-growing summer only load. BPA's irrigation load is projected to remain non-growing indefinitely. Irrigation adds nothing to BPA's winter peak requirements. Irrigation places demands on the BPA system only at times when BPA's seasonal demand is low.

Due to the seasonal nature of regional demand in the Northwest and the way the federal power system is being operated, irrigation has become an increasing valuable load for BPA. Irrigation provides BPA with a reliable 24 hour a day load during June, July and August, precisely when BPA's other regional loads are at their low point. This is especially important because the requirements for fish flows have increased the amount of hydropower which BPA must market during the summer period.

In short, continuation of the irrigation discount is justified based on the cost of service to irrigation. BPA is not required to incur new cost to serve irrigation. A seasonal irrigation rate mirrors the seasonal nature of electric demand in the Northwest and it complements the operational requirements of the federal system.

II. History of Irrigation Discount. I would like to provide the Committee with some history concerning the irrigation discount. There may be a false impression that the irrigation discount began in 1985. That is incorrect. With the exception of a six year hiatus from 1979 to 1985, the irrigation discount has, in various forms, been a part of the BPA general rate structure for over 50 years (see attached Exhibit 1, "History of Irrigation Discount", from "Irrigation Discount Background Paper", BPA, November 21, 1991).

Historically, the irrigation discount was based on the low cost and availability of surplus power in the summer irrigation season. Beginning with the 1985 rate case, BPA has justified the irrigation discount primarily as a response to economic uncertainty in the agriculture sector and the need to preserve the revenues provided to BPA by this load. Since 1985, BPA's justification for the discount has not addressed the cost of serving this load and its long term value to BPA and its ratepayers.

It is unfortunate that BPA has chosen to justify the irrigation discount primarily as a response to economic conditions in agriculture. BPA's irrigation load has unique value to BPA and it is justified on both a cost of service and system operation basis. Irrigation loads occur only during the off-peak summer

period. They are real regional loads which generally operate around the clock during the June, July and August period. The revenues from irrigation loads are dependable, not speculative. Because irrigation is an exclusively off-peak load, it costs less to serve and which provides valuable revenues and system benefits to BPA and its customers.

A. Irrigation Discount Has Existed Since 1942. BPA established a discounted rate for irrigation usage in 1942. The irrigation discount rate was initially based on BPA's need to market surplus power in the summer period. At the time, BPA had not included in its rate structure the now widely accepted principle that electric rates should reflect seasonal differences in the marginal cost of providing service. BPA had a uniform rate for all power sales year-around. The original irrigation discount did, however, reflect the fact that it cost BPA virtually nothing to generate surplus power during the summer period. This was true because overall demand on BPA was low during the summer, there was surplus hydro generating capacity in the Federal Columbia River Power System and river flows were highest during the summer.

During the period from 1942 to 1974, BPA's summertime irrigation rate was about 65% of the rate for year around preference customer loads.

B. Introduction of Seasonality to BPA Rates. Between 1974 and 1979, BPA phased out the irrigation discount. At the same time, in 1974, BPA introduced "seasonality" to its rates. Prior to that, BPA had "energy" and "demand" rates which were uniform year-around. Seasonality of rates was introduced primarily to reflect BPA's cost incurrence. BPA's system, like any utility system, must be built to serve "peak" demand during the year. This necessarily means that resources which are acquired by BPA to serve in peak periods are not needed during off-peak periods. In other words, the incremental costs which are incurred to serve peak loads are not necessary to serve off-peak loads.

The Northwest is a "winter peaking" utility system. BPA's costs are driven by the need to acquire additional electric resources at incremental cost to meet the growth of winter demand. It costs BPA more to serve demand during the winter peak period than during the off-peak summer period. Seasonality of rates is intended to reflect this seasonal differential in cost causation and give BPA's customers a correct "price signal" which will, hopefully, encourage the efficient use of power.

C. Irrigation Discount Phased Out When Seasonality Phased In. As the irrigation discount was phased out between 1974 and 1979, the seasonality of BPA rates were at their peak. BPA's rationale for not reinstituting an irrigation discount in the 1979

rate case was that a discount was no longer necessary because increased **"[seasonality] would benefit irrigators sufficiently."** [1]

D. Seasonality of BPA Rates Was Greatest in 1979. Seasonality, as it was applied by BPA in 1979, was not as favorable to irrigators as the irrigation discount before 1974, but it did roughly preserve the historic ratio between rates for summer only irrigation usage and year around usage. In 1979 BPA's winter energy rate was 1.9 mills/kWh and its summer energy rate was 1.0 mills/kWh (See Exhibit 1). Winter demand charges were $1.05 kW-month and summer demand charges were $0.93 kW-month.

Thus, the ratio between winter and summer energy rates was almost 2 to 1 and the ratio of the winter demand charge to the summer demand charge was 10 to 9. These ratios reflected the basic fact that BPA's need to acquire resources to serve growing winter loads was driving BPA's costs. Seasonality as applied in 1979 resulted in irrigators paying summertime rates of about 70 to 75 percent of the average rate for preference customers for year-around usage.

With the exception that BPA is now incurring substantial annual costs for fish & wildlife (approximately $300 million per year) which did not exist in 1979, it is true today, as it was in 1979, that the primary driver of BPA's costs is the need to acquire capacity and energy resources to serve BPA's growing winter loads. Recently, BPA's increasing costs has also included the cost of planned transmission facilities to assure reliable service for Puget Sound and Portland area peak loads in the winter.

E. BPA Has Significantly Reduced Seasonality Since 1979. Some winter peaking utilities have consistently objected to BPA's increased seasonality. It causes greater costs to be passed through to their retail consumers to pay for the increased cost of BPA power during the winter period. Because of their low usage in the summer, the increased cost of winter power was only partially offset by lower costs during the summer. In addition, many utilities had flat rates, or it was difficult to increase their winter period retail rates enough to cover their increasing BPA power purchase costs in the winter months. In other words, the extent of BPA seasonality was causing some BPA customers to have higher overall rates, or it was causing cash flow problems during the winter period, or both.

In response to these and other objections, BPA consistently reduced the seasonality of its rates in rate cases

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[1] The Record of Decision in the 1979 BPA rate case said, "Bonneville considered a special rate to irrigators to insure that the percentage increase in their power costs would not exceed the average increase for all Bonneville's customers. Bonneville chose not to implement such a rate because the seasonal differentials in the proposed rates would benefit irrigators sufficiently..." (pg. 13).

throughout the 1980s. This was done despite the fact that the cost of facilities to serve growing winter loads was then and is now the primary long range cause for BPA's growing resource expenditures.

The ratio of winter to summer energy charges declined from 2 to 1 in 1979 to about 9 to 7 by 1991. In addition, BPA's demand charge was made uniform throughout the year; in other words, the seasonality of demand charges was eliminated altogether. BPA's proposed 1993 rate adjustment reflects a modest reversal of the decade long trend to reduce or eliminate seasonal rates. Energy rates are slightly more seasonalized under the proposed PF-93 rate than under PF-91, however, BPA's demand charge would remain uniform year around.

F. Future of "Rate Design" and Seasonality is Uncertain. It is impossible to know what BPA will do concerning rate design and seasonality in the 1995 BPA rate case. BPA is in the midst of a major overhaul of the methodology by which it determines rate design. In fact, some of BPA's initial proposals suggest that it may utilize the results of a model known as the Power Marketing Decision Analysis Model ("PMDAM") to determine seasonality of BPA rates.

As we understand it, the basic purpose of the PMDAM model is to calculate the seasonal, daily and hourly cost of operating resources and the value of power based on a West Coast utility system model, including resources and usage in California and the Pacific Southwest. The PMDAM model is now being revised by BPA; however, earlier versions of the model base calculations of the cost and value of power on interregional "opportunity cost" of power, i.e. on the cost of operating resources and the value of BPA power in California and the Pacific Southwest. Because California and the Southwest are summer peaking systems, use of these results could completely reverse BPA's existing seasonality and make summer rates in the Northwest closer to or even higher than winter rates.

Such a result makes no sense to NIU. It continues to be true that BPA's primary responsibility and mission is as the regional bulk power and transmission supplier for the Northwest. This requires that BPA plan and acquire resources, including transmission, and therefor incur costs, primarily to serve growing winter loads in the Northwest. BPA rates should be based on BPA's cost incurrence for serving its native load, not the cost of producing power in California or the "opportunity cost" of not selling BPA power to California.

It would be inconsistent with BPA's statutory regional power supply mission and highly inequitable to summer only power users in the Northwest if BPA adopted a methodology which tied BPA rates to interregional "opportunity cost" rather than BPA's regional cost incurrence. Not only would summer only users pay higher rates than they should based on cost incurrence for summer

power, they would receive no offsetting benefit through lower winter rates because they place no demand on BPA in the winter.

We recognize that the PMDAM model is being revised and our concerns may be partially addressed by BPA. Nevertheless, we are presently very concerned about BPA's future course on the issue of rate seasonality.

G. Irrigation Discount Reinstated in 1985; Irrigation Load Benefits BPA. After being phased out in 1979, the irrigation discount was reinstated in 1985. BPA gave economic uncertainty in the farm sector as its primary reason for doing so. However, the discount also reflects the fact that a summer only load imposes less cost on BPA than a year-around winter peaking load, a fact which was not adequately reflected in BPA rates. Moreover, as further explained below, such a load provides system benefits to BPA.

H. Ratio of Summer Irrigation Rate to Year Around BPA Rate Has Remained Relatively Constant. Exhibit 2 illustrates the historic relationship between the average BPA rate to preference customers and irrigation rates since 1955. As previously noted, the ratio between the average irrigation rate for summer only usage and the average rate to preference customers for year around usage has remained relatively constant. Irrigation rates until the mid 1960's were about 65 percent of the average rate for year around use by all preference customers. Since the early 1970s they have averaged between 70 and 80 percent of the average annual rate for all preference customers.

In 1979 when the irrigation discount was phased out and seasonality reached its maximum, irrigation rates were 72% of the average annual Priority Firm rate. Since 1985, when BPA readopted the irrigation discount, the methodology used calculate the irrigation discount has been designed to cause irrigation rates to increase by the same percentage as the average annual increase in the Priority Firm rate for all BPA customers.

III. Irrigation Load is Unique, Costs BPA Less to Serve, and it is Beneficial to the BPA System. Irrigation sales represents 4 to 5 percent of BPA's direct power sales and revenues. Irrigation load occurs exclusively "off-peak". Irrigation sales plus induced power sales to agriculture related industries, represent 9.5% of BPA's revenues.

Continuation of the irrigation discount, or an equivalent rate, is justified because BPA's irrigation load costs BPA less to serve than its year-around winter peaking loads. It complements the operation of the federal hydro system and provides needed loads and revenues at a time of year when other BPA loads and revenues are at a low point. This is increasingly important to BPA as the operation of the federal system is modified to meet fish flow

requirements, thereby causing more hydropower to be available during the summer, especially at night.

The attached exhibit 3 roughly illustrates that the irrigation load occurs during BPA's "off-peak" summer period and at a time of high stream flows when BPA generates greater amounts of energy from hydropower. Although exhibit 3 shows only one year of operation of the hydrosystem, it indicates that in the months June, July and August, when the majority of irrigation load occurs, streamflows and BPA's generation from streamflow reached their maximum. In fact, generation from streamflow alone was sufficient to meet BPA's estimated firm energy load in June and July and most of the load in August.

To illustrate that irrigation load occurs during BPA's "off-peak" period, the monthly average of the Benton PUD irrigation load is shown on Exhibit 3 as solid bars which peak in June, July and August and decline to virtually nothing in the December, January and February period.

Having said that an irrigation discount, or equivalent rate is justified based on BPA's cost to serve this summer only load, it must be conceded that it is not possible to quantify that cost differential at this time. It costs less, that much is certain; however, as mentioned in my earlier comments on PMDAM, BPA's methodology for allocating its costs to rates is in the preliminary stages of being completely revised. Changing resource requirements, the changing operation of the Federal System, consideration of tiered rates, and many other factors make any attempt to quantify the cost of serving summer only loads premature. A great deal of analysis by BPA, NIU and other BPA customers will be devoted to this issue prior to the 1995 BPA rate case.

A. <u>Irrigation Load Occurs Exclusively During BPA's "Off-Peak" Period.</u> BPA's irrigation load is unique because it occurs only in the summer during BPA's off peak period. [2] Because irrigation is an exclusively off-peak load, it contributes nothing to BPA's need for additional resources in the November through February winter peak. As previously noted, BPA's winter peaks are primarily responsible for BPA's need to invest in additional

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[2] Irrigation usage occurs throughout the year approximately as follows:

November--March	0.1%
April	2.6%
May	8.4%
June	20.5%
July	38.7%
August	21.2%
September	7.3%
October	1.2%

generating resources and to construct additional transmission facilities. These investments are projected to drive BPA's resource costs. BPA's irrigation load provides a market for BPA power precisely when BPA's year-around loads are at their lowest. This improves BPA's load factor during the summer period and makes the BPA system more efficient.

B. Irrigation Load is Non-Growing; New Resource Costs Not Caused by Irrigation Load. Another reason the irrigation load costs less to serve is that it has been a non-growing load for the past 15 years [3] and it is projected to be a non-growing load for the foreseeable future. Because irrigation load has not grown, BPA has not and will not been required to acquire new resources to serve irrigation power users.

If the region's load growth were like irrigation's load growth, there would have been no need for the costly investments in new thermal resources and transmission facilities which occurred in the late 1970s and the 1980s and BPA rates would still reflect purely hydroelectric costs.

IV. The "Competitiveness Project", "Unbundling" BPA Services, "Tiered Rates", "PMDAM", and Other BPA Initiatives. BPA is currently involved in several major review processes through which BPA will not only completely review and possibly revise its method of designing rates, but its whole relationship with its customers and its method of conducting business. The initiative to "unbundle" the delivery and pricing of BPA's services, BPA's review of "tiered rates", BPA's comprehensive review of rate design, including the PMDAM methodology, the effort to reduce BPA costs and to operate more efficiently, and other important BPA initiatives are all part of an effort which has come to be known as the "Competitiveness Project".

BPA's efforts are, in part, a product of the Clinton Administration's initiative to "reinvent government". More importantly, however, they are the result of BPA and it's customers coming to a mutual understanding that BPA simply must become more efficient in order to continue to deliver cost-effective products to its customers. The need is clear. BPA must succeed in this effort if it is to remain the region's primary provider of bulk power and transmission services.

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[3] The irrigation load of the 15 largest irrigation utilities in the Northwest actually declined by about 8% from 1981 to 1987. Since 1980 irrigated acreage in the Northwest has increased by 1.3% (0.1% increase per year). In that same period, sprinkler irrigated acreage increased by 16% due primarily to conversion of flood irrigated land to sprinklers. Flood irrigation uses little or no electricity but is a relatively less efficient method of applying water. Absent any improvement in efficiency, a 16% increase in sprinkler irrigated acreage implies that electric usage should also increase by about 16%. However, irrigation load has averaged only a 0.6% annual increase since 1979, or about 7.5% total from 1979 to 1991. Energy conservation efforts by irrigators and irrigation utilities are primarily responsible for the difference.

Utilities (and all of their ratepayers), whether publicly or privately owned, and whether or not they rely exclusively on BPA for their power supply, have long enjoyed the cost benefits of the federal Columbia River Power System. The region's economy is largely built on the foundation of the Federal System.

For example, in irrigated agriculture, relatively low cost BPA power for irrigation pumping has been a cost "equalizer" for Northwest irrigators who compete with irrigated farmers from other less arid regions and/or regions which are located closer to markets. If BPA becomes uncompetitive, irrigators will pay higher rates to their retail utility and, ultimately, lose their cost "equalizer."

Having said that the Competitiveness Project is necessary; it must be recognized that at this stage, the Competitiveness Project is not a well defined proposal or set of proposals to reform BPA or to revise its operations. Rather it is a process; it is a commitment by BPA to thoroughly review BPA operations and to develop specific proposals to reform BPA.

NIU supports the Competitiveness Project. We believe it is an important BPA initiative. This is not to say, however, that NIU or any NIU member endorses "unbundling" or "tiered rates" or any other specific proposal or program as it may ultimately be defined and put forward by BPA. The distinction is this, we support BPA's commitment for a top to bottom review of BPA operations, but we do not endorse in advance every action or proposal which may ultimately emerge in the name of the Competitiveness Project. We simply need to understand the details of any specific proposal or program before we agree to support it.

V. <u>The Irrigation Discount and the Competitiveness Project.</u> In the short run, the Competitiveness Project means uncertainty for all BPA customers and their consumers, including irrigators. We accept that uncertainty. We believe that in the long run, the importance of improving the efficiency of BPA outweighs the problems created by uncertainty. If BPA succeeds, it will find ways to keep its costs and rates down for all BPA utility customers and their retail consumers, including irrigators.

The Competitiveness Project will involve a broad ranging review of BPA rates, rate design and programs. We understand that the irrigation discount will come under scrutiny by BPA, as will all other matters involving rates and programs. We believe, that keeping BPA competitive is not incompatible with retention of the irrigation discount or an equivalent rate. This is true because the irrigation discount or an equivalent summer period rate is soundly based on cost of service, cost causation and cost benefits to BPA. The following are some of the reasons why the irrigation discount and the Competitiveness Project are not incompatible.

A. The Irrigation Discount Reflects the Lower Cost of Serving a Non-Growing, Off Peak (Summer Only) Loads. It is impossible to say at this time what principals of rate design Bonneville will ultimately adopt. In an environment of "unbundled" services or "tiered rates" it may be that there will no longer be a single Priority Firm ("PF") BPA rate. There may be several "tiers" of different PF rates depending on the quality and quantity of power purchased and differing types of firm power services.

Notwithstanding this uncertainty, there is good reason for BPA to conclude that non-growing, off-peak loads such as irrigation costs BPA less to serve and they provide significant system benefits. I have already mentioned that, the cost of acquiring new energy and capacity resources and transmission facilities to meet BPA's growing winter energy and capacity needs is currently driving BPA's costs. BPA is not energy or capacity constrained in the summer period. If it were not for growing winter loads, BPA would be incurring very little additional cost for resources.

These basic facts about BPA's cost causation must ultimately translate into significantly lower rates for power users in the summer period. This is especially true as Bonneville moves from a period of temporary surplus in the 1980s to a period of increasing need for relatively costly new resources in the 1990s.

1. Use of PMDAM to Price BPA Power May Distort Cost Causation and Send Inappropriate Price Signals. In this regard, I reiterate my earlier comments about BPA's proposal to use the PMDAM model as the basis of a methodology for pricing power. To the extent that using PMDAM would cause BPA rates to reflect the "opportunity cost" or value of power in a west coast system, including California and the Pacific Southwest, it appears to be an inappropriate method for use in BPA rate design. Basing the cost of power in the Northwest on its value in California could result in a gross distortion of seasonal rate design.

Depending how PMDAM is applied, it could cause BPA to reverse the current seasonality of BPA rates to reflect power values in a summer peaking system. This makes no sense because BPA's primary statutory mission and its long term contractual obligations require it to acquire and supply power and transmission for Northwest loads. BPA must acquire the resources and build the transmission facilities to carry out this mission. This is what drives BPA costs. BPA rates should be based on cost causation for serving Northwest loads, not on the value of power in California.

2. NIU Will Support Seasonal BPA Rates. NIU has and will continue to participate in BPA public processes to develop an appropriate methodology for rate design in the 1990s. We believe that a strongly seasonal BPA rate structure based on BPA's cost to serve its Northwest customers is the appropriate methodology.

B. Tiered Rates. The concept of tiered rates has been much talked about among BPA and its customers. To date, however, the concept of tiered rates remains ill defined. NIU is not convinced that a tiered rates system would be beneficial; however, we do believe that the concept illustrates an important point. Under a tiered rate system, power would be priced in blocs which reflect the higher costs of resources required to serve incremental loads. In other words, growing loads should receive a "price signal" which reflects the fact that load growth generally causes increasing cost.

Conversely, the concept of tiered rates suggests that non-growing loads should not bear the high costs of acquiring new resources to serve incremental load. I have already noted that BPA's irrigation load has essentially been non-growing for the past fifteen years, and that it is projected to remain flat or even to decline slightly for the foreseeable future. If BPA moves to a tiered rate system, it should reflect the fact that irrigation is a non-growing, off-peak load which has imposed no additional resource cost on BPA and will impose no additional cost for the foreseeable future.

C. Cost of Fish Flows. An important new cost which Bonneville faces is the approximately $300 million per year it expends related to the release of water for fish flows and other investments in fish and wildlife enhancement activities. The water budget imposed by the Regional Power Council's Fish and Wildlife Plan and by the Endangered Species Act requires that water be run through the system generating excess amounts of low cost hydropower in the summer.

Essentially, water which was previously stored and used to generate power to serve winter loads is now used for fish flows. The cost of replacing that low cost resource with other higher cost resources for use in the winter should be reflected in increased seasonality of BPA rates in the winter period. Likewise, the increased availability of low cost hydropower during the summer should reduce the cost of power during the summer.

D. Cost of BPA Conservation Programs. A serious inequity presently exists in the distribution of conservation program dollars by BPA and in the allocation of energy conservation costs to rates. A recent BPA study (Office of Power Resources, "Conservation Expenditures by Area Office," spreadsheet data, July 1991) indicates that between 1980 and 1989, winter peaking utilities in Western Washington received conservation funding from BPA of $170 million or 8.7 cents for every dollar of revenue paid to Bonneville. At the same time, NIU members received $42 million or 3.7 cents for every dollar of revenue paid to Bonneville. Proportionally, these winter peaking utilities received financial support 2.4 times greater than that received by NIU members. Under the current methodology, when these conservation expenditures are

allocated to rates, they are allocated to all firm loads and are not seasonalized.

This arrangement raises several equity questions. First, the irrigation sector has placed much less resource acquisition need on the region compared to other sectors. However, the irrigation sector pays for conservation resource acquisition through increases in the PF rate even though its need for new resources is much less than other sectors. Second, the higher rate of conservation payments to winter peaking utilities, coupled with their customers' reduced power bill payments, has the end effect that irrigation customers of NIU members not only receive proportionately less conservation funding, their customers receive less benefits while shouldering a greater proportional share of new resource acquisition costs. Third, it appears quite likely that significant irrigation efficiency measures are being paid for by private capital rather than Bonneville programmatic dollars. The bottom line is that irrigators are not only paying a disproportionate share of conservation program costs for others, and receiving less benefits, they are also using their own dollars to fund on-farm conservation efforts which reduce demand on BPA.

E. Value Added to BPA Through Water and Energy Conservation Programs Carried out by Irrigation Utilities. Another system benefit which NIU members and irrigators can and are providing to BPA is the value of water and energy savings through expanded on-farm energy and water conservation programs.

Irrigated agriculture withdraws only 5 to 7 percent of stream flows. Thus, even a significant improvement in water use efficiency is likely to result in only a fractional improvement in stream flows. Nevertheless, water efficiency measures adopted by irrigators may provide important benefits by increasing water availability and water quality at particular times of the year in specific situations to help meet BPA's in-stream fish and wildlife requirements.

In 1991 BPA challenged NIU to submit a proposal to BPA which would provide for an increased NIU role and irrigator involvement in regional energy and water conservation programs. NIU responded to this challenge by submitting a proposal for "Phase One" of a comprehensive energy and water conservation program which we called the "NIU Waterwise" program.

The NIU Waterwise program was designed to significantly increase the market penetration of existing BPA irrigation energy conservation (hardware retrofit) programs and to make water use efficiency activities an explicit program objective. The NIU Waterwise program involved increasing technical assistance to farmers for on-farm energy and water conservation through improved

irrigation management. NIU has executed two contracts with BPA to carry out these activities. [4]

Another aspect of this effort is the BPA "Exhibit H" contract with its irrigation utility customers. The Exhibit H contract provides that irrigation utilities will provide irrigation management services (water use efficiency) to their irrigation customers. Under Exhibit H NIU has assumed the role of "joint action contractor" to implement BPA's Irrigation Management Program ("IMP") and Northwest Irrigation Network ("NIN") programs under BPA's "Waterwise Exhibit H" contract with its utility customers. Under this program, NIU delivers water management services to irrigated farmers for NIU members.

Finally, NIU proposed a "baseline study" to identify additional opportunities for energy and water conservation activities which NIU and other groups could undertake with irrigators and other water user organizations. Implementation of a "baseline study" was deferred by BPA because of a bid protest by the Columbia Basin Institute, an environmental group.

While these energy and water conservation efforts are in their initial phase, NIU believes that irrigators can provide significant value to BPA through these programs. This will provide value and benefits to BPA and an additional cost justification for retention of the irrigation discount or its equivalent. If BPA desires, NIU will continue to be actively involved in expanding and marketing agricultural energy and water programs. We are anxious to continue to work with BPA to identify and implement energy and water conservation opportunities.

VI. Conclusion. Mr. Chairman, NIU appreciates your interest in the future of BPA and many important issues confronting the agency today. We especially appreciate the opportunity to express our views to the Committee on the future of BPA and, in particular, of the irrigation discount rate.

This testimony is not intended to be a definitive discussion on the irrigation discount. Given the uncertainty about the future of BPA rate design and marketing programs, there will be many additional discussions with BPA and other customers about the irrigation discount and other features of BPA's rate design.

We believe that the "Competitiveness Project" is a worthwhile undertaking for BPA and the region, even though we may ultimately disagree with specific proposals or actions which come out of it.

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[4] BPA/NIU technical assistance contracts include: the Irrigation Conservation Technical Assistance Program II ("ICTAP II") and the Irrigation Management Implementation Assistance program ("IMIA").

Finally, we believe that retention of the irrigation discount is not incompatible with the Competitiveness Project because the discount, or an equivalent summer only use rate, is cost justified. NIU will participate actively and constructively in BPA's processes to keep BPA competitive.

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EXHIBIT 1

History of Irrigation Discount

Between 1942 and 1979 BPA offered discounted rates to public utilities for their irrigation loads. In the summer, when the availability of surplus power was large and its market small, discounted rates built load and increased sales. Discounts for irrigation loads were phased out over a five-year period starting in 1974 with the completion of storage projects in the upper Columbia and development of markets for surplus power. Discounted rates have been in effect again since 1985 due to the poor economic conditions in the farm sector.

History of Irrigation Discount

1942 to 1991

Year	Rate Schedule	Period	Preference Rates: Energy	Preference Rates: Demand	Discount: Energy	Discount: Demand
1942	F-2	Apr-Sep	First 360 kWh*kW/month @ 2.5m/kW	$0.75/kW/month	1/	Maximum $4.50/kW-year
			Add'l @ 1.0 m/kWh			
1944	E-2	*	First 200 kWh*kW/month @ 2.0m/kW	*	1/	*
			Add'l @ 1.0 m/kWh			
1946	E-3	*	*	*	1/	*
1948	E-4	May-Sep	*	*	1/	Maximum $6.00/kW-year
						Nonfirm @ 50% of demand charge
1954	amendment	*	*	*	0.4 mills/kWh	1/
					10% increase in energy for losses	
1965	E-5	*	1.25 m/kWh	$0.95/kW-month	0.6 mills/kWh	1/
					10% increase in energy for losses	
1974-1979	EC-6	*	Winter: 1.9 m/kWh	Winter: $1.05/kW-month	Discount phased out over five-year period	
			Summer: 1.0 m/kWh	Summer: $0.93/kW-month		
1985	PF-85	Apr-Aug	Winter: 16.6 m/kWh	Winter: $4.33/kW-month	3.7 mills/kWh	1/
			Summer: 14.0 m/kWh	Summer: $2.60/kW-month	2/	
1987	PF-87	Apr-Oct	Winter: 18.4 m/kWh	$3.46/kW-month	4.6 mills/kWh	1/
			Summer: 14.4 m/kWh		2/	
1989	PF-89	*	*	*	2/	1/
1991	PF-91	*	Winter: 18.7 m/kWh	$3.60/kW-month	3/	1/
			Summer: 14.7 m/kWh			

1/ No discount on this component.

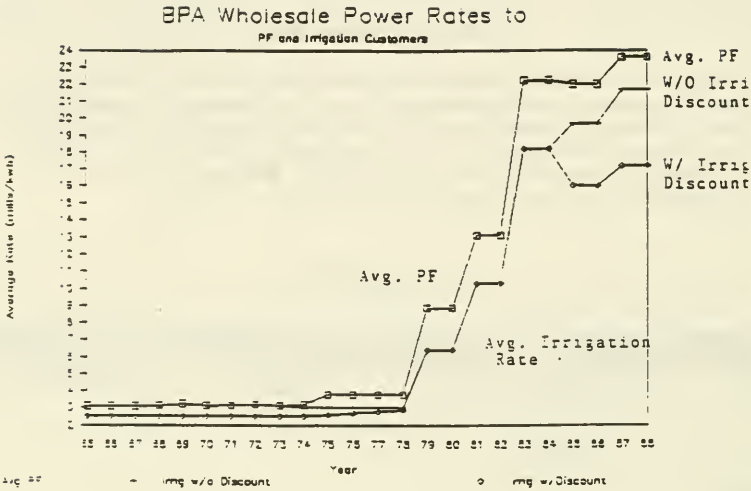
2/ Also available to exchanging public and private utilities.

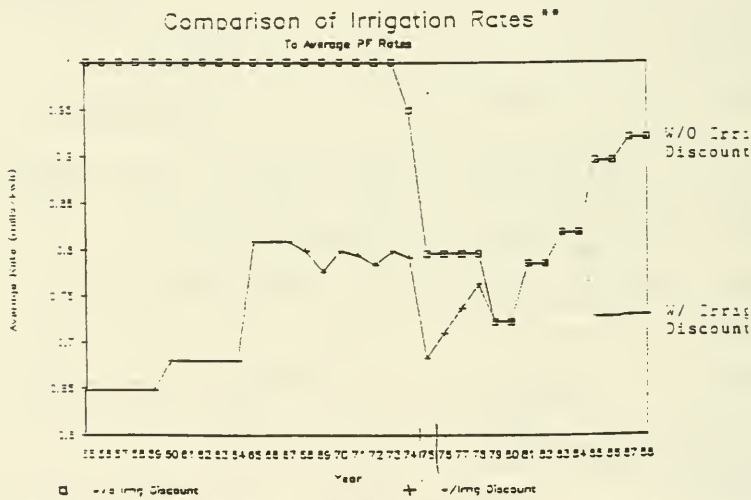
3/ No longer applicable to exchange loads of public utilities.

(1:Irrhist.XLS)

(RAD-PMLC-7/22/91)

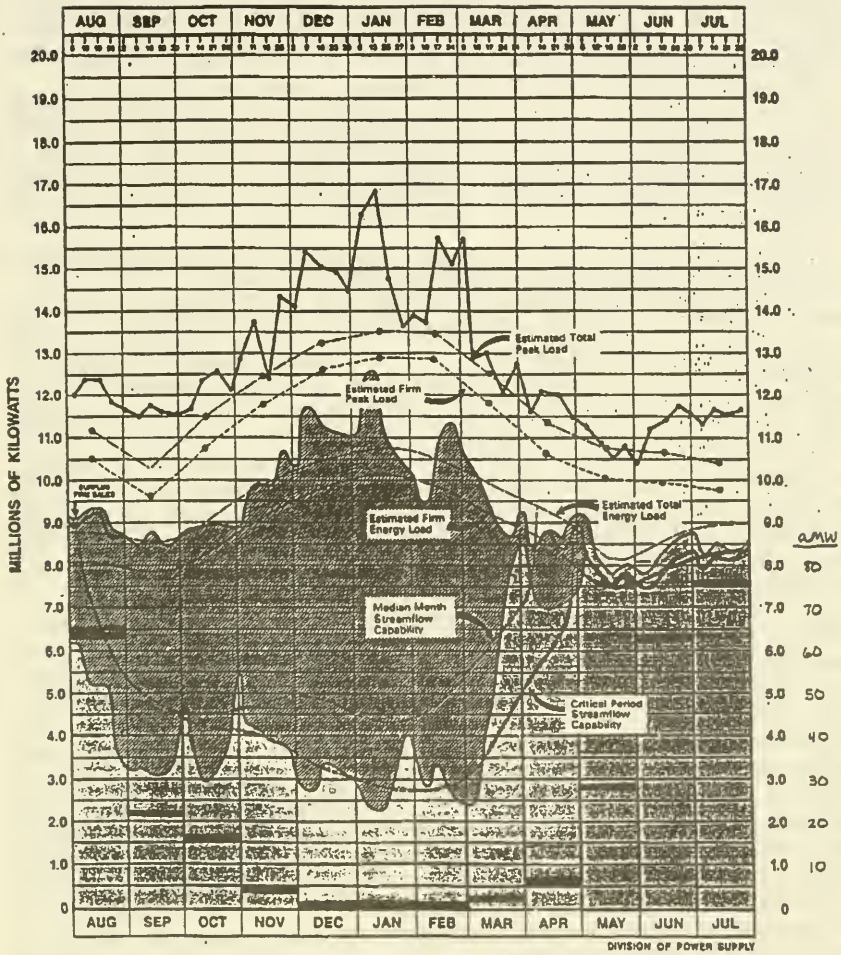
EXHIBIT 2





**NOTE: Until 1974 BPA had a uniform rate year round. After 1974 adopted "seasonal" rates with lower rate in summer. The "Average PF Rate" line depicted in this graph represents the average year around rate until 1974 and the average summer rate after 1974.

EXHIBIT 3



DIVISION OF POWER SUPPLY

LOADS AND RESOURCES
BONNEVILLE POWER ADMINISTRATION

AUGUST 1992 - JULY 1993

STREAMFLOW GENERATION — OTHER GENERATION STORAGE, THERMAL, MISC.

Solid bars represent energy sales to BPUD large irrigation accts for 8/92 - 7/93 in scale shown on right.

STATEMENT OF WILLIAM P. KITTREDGE

Mr. KITTREDGE. Thank you, Chairman DeFazio. On behalf of the ratepayers of Springfield Utility Board, I wish to extend the thanks of the Board for the opportunity to represent them today. Springfield is a full-requirements non-generating customer of the Bonneville Power Administration.

BPA continues to be a major force in the Pacific Northwest. BPA's activities impact each person here on a daily basis. Over the 50 years since its inception, BPA has been a dynamic engine of change bringing power to industry and home, city and farm. Founded on noble principles, refined by the Act, BPA has served the Northwest well.

Today I want to hit on two major issues, competitiveness and accountability. More detail is in my written testimony.

Competitiveness is a goal SUB embraced over 10 years ago. Since 1982, SUB has reduced overheads, mostly in personnel, over 30 percent while increasing service levels and unbonded capital investment in both our electric and water utilities. We believe that our experience and success well qualifies us to provide a perspective.

Overall, SUB believes that BPA's efforts lack a sense of urgency and a real appreciation of the problem. An internal BPA notice trumpets "cost cutting," advising that BPA will no longer supply briefcases, a savings of $13,422. I would probably say that the desktop publishing involved in putting this thing out, which I took off a BPA bulletin board, exceeded that savings.

SUB is greatly disturbed by the Administrator's talk of reducing staffing levels at BPA by between 600 and 800 people between now and 1997. That is approximately the current attrition rate of 5 percent per year, and represents absolutely no progress toward true cost reduction.

SUB urges a reduction of 1,000 FTE by the end of fiscal 1994 and serious cost-reduction negotiations with contracting state and federal agencies. Many reductions can be achieved by the elimination of unnecessary functions—for instance, elimination of BPA's 60 staff fish biologists, which replicate all the fish biologists in the appropriate agencies, and immediate transfer of responsibility for conservation programs to local utilities.

Conservation programs now employ approximately 400 FTE and consume as much as 30 percent of the program budgets. Beginning the transition to utility-funded conservation envisioned under SUB's tiered-rates proposal immediately would increase conservation acquisition and reduce costs. SUB estimates that approximately 40 FTE would remain at BPA to audit the use of federal funds, ensuring compliance during the transition.

Elimination of the area offices is another major step BPA should take immediately. These offices are generally redundant and retard progress. PacifiCorp, whose president testified earlier, is an investor-owned utility serving seven states, including Oregon, and it has no analogous management layer. As a result, it is moving far ahead of BPA in its conservation programs.

We know from our own experience that the process is neither pleasant nor painless, but it is necessary and it is taking place at businesses across the Nation. It is taking place at General Motors,

IBM, and our own regional success story, Nike. In fact, this morning's *Register Guard* talks about a 400 FTE reduction at the United States Forest Service, so I am somewhat mystified by the Administrator's apparent inability to lay people off from the federal system.

If its customers are to be competitive in the world marketplace of today, the same type of actions must take place at BPA. If BPA is to remain a competitive service provider, it must act quickly to reduce its cost of doing business.

Should BPA fail to become truly competitive, it will over time become increasingly irrelevant. Depending upon the energy choices of the Northwest and world economic conditions, BPA could easily enter a downward spiral from which it would not recover without a massive federal bailout.

My second topic is accountability. All of us in the region, SUB included, engage in a collective fantasy. We pretend that by diluting—regionalizing—our mistakes in the vast FBS resource makes everything okay.

As a result, our region has a complex system of special deals and fiascos. They go by various names—low density discount, irrigation discount, variable rate, Trojan, WPPSS—but they all share a common reality: the people and organizations responsible escape the consequences of their decisions by melding the costs into the regional rate pool. Many of these same players are now at the forefront expressing serious concerns about the relatively minor expenditures being made for fish and wildlife mitigation, $300 million for fish versus an estimated minimum half billion dollars to decommission WNP–2.

I would echo my peer Mr. Scarborough's testimony on the DSIs, including the need for an audit.

To increase accountability of both BPA and at the utility level, SUB supports the concept of tiered rates. Our implementation plan is contained in my written testimony, but the principle is simple: create accountability for the region's utilities. Under tiered rates, the responsibility, accountability and risk for developing resources (including conservation), belongs to the utilities and its customers. BPA will only require resources for tier 2 or subsequent tiers upon receiving definitive notice from its customers that they wish to place load on BPA.

Tiered wholesale rates, as outlined in our written testimony, provide the utility with tools and clear price signals. Under tiered wholesale rates, the retail rates paid by industrial customers of those utilities reflect that utility's decisions, not BPA mandates.

As BPA implements tiered rates, it becomes possible to unbundle products and services as independent and discrete marketable commodities, not associated with any particular tier. Unbundled services should be priced, as should all BPA services, at cost.

Unfortunately, BPA does not have a cost accounting of a market-driven organization and lacks concrete information concerning the costs of its services. Revision of that system must proceed the unbundling of services. BPA cannot very well sell something it does not know the price of.

The decentralization envisioned by Springfield in an unbundled, tiered-rate BPA is not the equivalent of chaos. Regional coordination of existing resources and planning for new resources will still

take place, and there will be more minds on the job. The coordination agreement, or some successor, will still be in place. Resources, including both conservation and generation, that are cost effective will be acquired more flexibly with decentralized decision-making without the loss of coordination while BPA provides open-access transmission.

Integrated resource planning and least-cost planning must become common utility practice.

It is essential that transmission services, BPA's premier product, continue to be offered at a regionally, cost-competitive level. It is also critical to the success of the region for BPA to provide open access to these transmission services with a sensitivity toward regional preference.

With regard to the DSIs, it is clear that they are not preference customers. SUB believes that the DSIs should pay no less than a comparable industrial customer of utilities. Any new contracts with them should include significant notice requirements for load elimination or reduction and a market sensitive method for calculation of the VOR. Our understanding of the current situation with regard to the VOR is included in our written comments.

In conclusion, the directors of the Springfield Utility Board believe that a competitive, cost-effective BPA providing open-access transmission and load-shaping services is the next logical step in Bonneville's development. We believe the following steps are needed to accomplish that:

Prompt reductions in staffing levels to achieve cost control.

Immediate shift from the "command-and-control" model to a BPA funded utility implemented conservation for transition period to end no later than October 1, 1997.

Implementation of tiered rates in the 1995 rate case.

Undertake an immediate effort to establish a cost accounting system as a prerequisite to unbundling products and services.

And legislatively mandated least-cost planning and integrated resource planning.

SUB believes that these first steps, supplemented with power sales agreements that increase accountability, will effectively begin the transition to the 21st century.

Thank you.

[Prepared statement of Mr. Kittredge follows:]

STATEMENT OF WILLIAM P. KITTREDGE

BONNEVILLE POWER ADMINISTRATION

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE SPRINGFIELD UTILITY BOARD TASK FORCE

HOUSE COMMITTEE ON NATURAL RESOURCES

FIELD HEARING - EUGENE, OREGON

SEPTEMBER 25, 1993

Statement of William P. Kittredge, Director

Springfield Utility Board

September 25, 1993

Chairman DeFazio, on behalf of Springfield's ratepayers, I wish to extend the thanks of the Board for the opportunity to represent them today.

INTRODUCTION

The Bonneville Power Administration continues to be a major force in the Pacific Northwest. BPA's activities impact every person here on a daily basis. Over the 50 years since its inception, BPA has been a dynamic engine of change bringing power to industry and home, city and farm. Founded on noble principles, refined by the Act, BPA has served the Northwest, and the nation, well.

Changing times are always unsettling. So it is now, as our region faces challenges dictated by changing economic, environmental and social conditions; that we have the opportunity to pro-actively set a new course - a course that will allow the Pacific Northwest to continue to enjoy the economic opportunity and quality of life that BPA has been so instrumental in making possible. I am here today in that spirit to add the SUB's perspectives to the debate.

COMPETITIVENESS

"Competitiveness" is a goal SUB embraced over 10 years ago. Since 1982, SUB has reduced overheads, mostly personnel, over 30% while increasing the service levels and unbonded capital investment in both our electric and water utilities. We believe that our experience and success well qualifies us to provide a valuable perspective.

Overall, SUB believes that BPA's efforts lack a sense of urgency and a real appreciation of the problem. A BPA internal notice (copy attached) trumpets "Cost Cutting" advising that BPA will no longer supply briefcases, a saving of $13,422!!

SUB is greatly disturbed by the Administrator's talk of reducing staffing levels at BPA by "600-800 FTE" by 1997. This is approximately the current attrition rate of 5%.

SUB urges cuts of 1000 FTE by the end of calendar 1994 and serious cost reductions from contracting state and Federal agencies. Many reductions can be achieved by the elimination of unnecessary functions - such as BPA' 60 staff fish biologists - and immediate transfer of responsibility for conservation programs to the local utilities.

The conservation programs now employ about 400 FTE and consume as much as 30% of the program budgets. Beginning the transition to utility-funded conservation envisioned under SUB's tiered rates proposal immediately would increase conservation acquisition and reduce costs. SUB estimates that 40 FTE could remain at BPA to audit the use of the Federal funds, insuring compliance during the transition.

Elimination of the Area Offices is another major step BPA should take immediately. These offices are generally redundant and retard progress. PacifiCorp, an IOU serving 7 states, including Oregon, has no analogous administrative level and, as a result, is moving far ahead of BPA in its conservation programs.

We know from our own experience that the process is neither pleasant nor painless but it is taking place, of necessity, at businesses across the nation. General Motors, IBM and, our own success regional story, Nike are making substantial staff reductions in order to be more competitive and cost effective.

If its customers are to be competitive in the world marketplace of today, the same must take place at BPA.

If BPA is to remain a competitive service provider, it must move quickly to reduce its cost of doing business.

Should BPA fail to become truly competitive, it will, over time, become increasingly irrelevant. Depending upon the energy choices of the Northwest and world economic conditions, BPA could easily enter a downward spiral from which it could not recover without a massive Federal bailout.

ACCOUNTABILITY

Accountability is my second major theme today. All of us in the region, SUB included, engage in a collective fantasy. We pretend that diluting - regionalizing - our mistakes in the vast FBS resource makes everything OK.

As a result, our region has a complex system of special deals and fiascos. They go by various names; Low Density Discount, Irrigation Discount, Variable Rate, Trojan and WPPSS, but share a common reality - the people and organizations responsible escape the consequences of their decisions "melding" the costs into the regional rate pool. Many of these same players, now express serious concerns over the expenditures for fish and wildlife mitigation.

To increase accountability, both at BPA and at the utility level, SUB supports the concept of tiered rates. Our implementation plan is contained in my written testimony but the principle is simple; create accountability for the region's utilities. Under tiered rates, the responsibility, accountability and risk for developing resources (including conservation), belongs to the utilities and its customers. BPA will only acquire resources for tier two or subsequent tiers upon receiving definitive notice from its customers that they wish to place load on BPA.

There are those who will resist changes of this type and urge special consideration for their particular situation. In almost every case, these are to the region's detriment.

Tiered wholesale rates, as outlined in our written testimony, provide the utility with tools and clear price signals. Under tiered wholesale rates, the retail rates paid by industrial customers of those utilities reflect that utility's decisions, not mandates from BPA.

As BPA implements tiered rates, it becomes possible to unbundle products and services as independent and discrete marketable commodities, not associated with any particular tier. Unbundled services should be priced, as should all BPA services and products, at cost.

Unfortunately, BPA does not have the cost accounting of a market-driven organization and lacks concrete information concerning the costs of its services. Revision of the system and the establishment of true costs must precede institution of unbundled services - BPA can't very well sell something if it does not know the cost.

SUB believes that the costs of fish and wildlife mitigation must be associated with the benefits produced. The first tier FBS would include those fish and wildlife costs associated with the current system under SUB's proposal.

The decentralization envisioned by Springfield in an unbundled, tiered rate BPA is not the equivalent of chaos. Regional coordination of existing resources and planning for new resources will still take place, and there will be more minds on the job. The Coordination Agreement (or some successor) will still be in place. Resources (including both conservation and generation) that are cost effective will be acquired more flexibly with decentralized decision making without any loss of coordination while BPA provides open access transmission.

It is essential that transmission services, BPA's premier product, continue to be offered at a regionally, cost-competetive level. It is also critical to the success of the region, for BPA to provide open access to these transmission services with sensitivity to regional preference.

With regard to the DSI's, it is clear that they are <u>not</u> preference customers. SUB believes that the DSI's should pay no less than comparable industrial customers of utilities. Any new contracts with them should include significant notice requirements for load elimination or reduction and a market sensitive method for calculation of the VOR. Our understanding of the current situation is included in our written comments.

CONCLUSION

The Directors of the Springfield Utility Board believe that a competitive, cost-effective BPA providing open access transmission and load shaping services is the next logical step in Bonneville's development. We believe the following steps are needed to begin the transformation:

1. Prompt reductions in staffing levels to achieve cost control.

2. An immediate shift from the "command-and-control" model to a BPA funded, utility implemented conservation for transition period to end no later than October 1, 1997. By that time we must have completed a shift to non-regionalized resource acquisition.

3. Implementation of tiered rates in the 1995 rate case.

4. Undertake an immediate effort to establish a cost accounting system as a prerequisite to unbundling products and services.

SUB believes that these first steps, supplemented with new power sales contracts that increase accountability, will effectively begin the transition to the 21st century BPA.

I would be happy to respond to any questions you may have.

In addition to our verbal testimony, Springfield Utility Board submits the following for the record.

Value of Reserves (VOR)

SUB's understanding the of current rate and VOR is as follows:

The DSI Variable Industrial Rate fluctuates with the market price of aluminum between a floor of 11.1 mils and a ceiling of 21.7 mils. The price aluminum has put the rate at the floor limit for over a year. Given the situation in Russia and elsewhere, there is no reason to think the situation will ameliorate in the near future.

The demand charge is fixed until August 1993 at $5.25 per kilowatt month (about 7 mils) making the total 18.1 mils, lower than the current PF rate.

The VOR estimates the value to BPA of the reserves provided by DSI interrupt ability. It is based on a proxy gas turbine: the alternative source if BPA could not restrict DSI loads.

Put another way, the VOR attempts to estimate the cost to BPA of acquiring sufficient gas turbine reserves if the DSI's had firm power contracts <u>without</u> restriction rights.

The value of DSI reserves, as determined in 1985, was about $90 million. To this sum was added the projected costs to the DSI's of a BPA outage. The two items totalled about $92 million. About half of this amount ($46 million) was then allocated to the DSIs as a credit (discount) on their annual power bills. Escalated for inflation. it is now worth about $60 million.

The VOR is based on two important assumptions, both of which appear to be out of date.

The first is that the DSIs provide two quartiles (1200 MW) of capacity reserves for planning purposes. We believed that to be the case until January 1993, when BPA published a new Pacific NW Loads and Resources Study (White Book), which showed that BPA counts only one quartile for reserves(600 MW). For reasons discussed below, this change has not triggered a revaluation of the VOR to ensure it accurately reflects BPA's actual planning assumptions.

Another change is the cost of the gas turbine generation. Springfield Utility Board is evaluating 6 gas turbine based proposals at this time. BPA's assumptions do not reflect the cost of the plant that would have to be acquired if the DSIs did not provide reserves. Currently the calculations are based upon a 14% interest rate. Today's rate is closer to 7%. This should significantly lower (on the order of 1/2) the cost of the plant

and, therefore, the value of reserves.

The contract for VOR cannot be modified automatically to reflect the reduction in the values of the quartiles used for planning purposes.

The reason is that BPA "locked in" the essential components of the VOR in 1987. This "lock" was approved as part of the IP-PF Rate Link, a BPA rate proceeding; it expires in mid-1996.

The idea of an administrative "lock" in which key elements are frozen in time and cannot change to reflect changing conditions is a legal and policy issue that ought to be closely examined. It is certainly not what I would call prudent. It is reminiscent of the WPPSS "take or pay" contracts.

The effect of the "lock" has been to preclude testimony during the 1993 rate proceedings on the value of reserves. Absent some effective way to deal with this issue at this time, the region will have to wait and hope that it can be dealt with in the next rate case or upon expiration in 1996. However, BPA's long term financial plans clearly assume the current arrangement will continue to the end of the 10 year planning horizon.

The process for restriction of second (and third) quartile DSI load is contained in Section 7(f)(3) and (d) and (e)(1). It appears to require notice be given by June 1. Failure to provide this notice precludes action until next year under most circumstances.

Other requirements include the administrator requesting voluntary curtailments (which has not been done) and recalling conditional or provisional sales that can be recalled. This condition has already been met. A letter to Bob Olsen dated April 22, 1993 (reference PSC) signed by Sandra K. Smith for Mark W. Maher BPA, director of power supply, states "There no existing power sales contracts with BPA customers that include conditional or provisional sales for power that can be recalled". Therefore, it appears that the only requirement prior to notice of curtailment of the second quartile is the administrator's call for regional voluntary curtailment of non-essential loads.

The short and midterm effect is to limit BPA's financial flexibility and reduce the reliability of Treasury payment while requiring a regional subsidy to the DSIs which is not provided to equally stressed industrial customers, such as Boeing and Globe Metallurgical.

Principles for Tiered Rates

1. Implementation of tiered rates must be accomplished within the structure of existing statutes.

2. Tiered rates require new BPA Power Sales and Residential Exchange Contracts.

   As a general principle, SUB believes that **exchange benefits** should not be *greater* as a result of implementation of tiered rates. Furthermore, the IOUs should only be entitled to exchange for FBS resources only. Since there are no replacements to the FBS (see principle 19.), the Average System Cost is capped at its current level and only current IOU resources are entitled to exchange.

3. All existing FBS and contracted resources are subject to public **preference**, including those that yield unbundled projects and services and those used to make sales to the DSIs and nonfirm energy.

4. **New preference customers** shall be able, with reasonable notice, to request and receive an allocation of BPA resources, including the FBS, subject to public preference.

   SUB proposes that new preference customers should receive an allocation of the FBS Tier 1 allocation exactly equal to the resources the new customer brings to the pool. These resources will be rendered at average system cost under the following two conditions:

   a. At the time of entering new tiered rate power sales contracts, a new preference customer's ASC must be equal to or below the *region's* average ASC.

   b. In the future, a new preference customer's ASC must be at or below the marginal rate, (i.e. the price of the last tier).

5. **Regional preference** shall be retained.

6. Customers shall be free to make their own resource decisions, subject to applicable laws and regulations. SUB asserts that utilities will have all rights and responsibilities of resource ownership and planning.

7. Regional customers must have the option to have BPA meet their loads and load growth in the second tier.

8. Customer rights to displace purchases from BPA should be

clearly defined.

9. Allocations of power must be stable and predictable.

10. SUB asserts that the size of the Tier 1 allocation should be based on 3 year average, weather adjusted loads placed on BPA. Employing historic test years are better than future test years because they represent actual load, not estimated.

    Exceptions should be made for contingency contracts.

11. Prices for each tier must be based upon the costs of the resources in each tier (only actual, not theoretical, costs). Opportunity costs in regions outside the Pacific Northwest should not be used to determine marginal costs in the Northwest. Prices for power and all services to deliver that power should not be inflated by the foregone revenue from potential sales outside of the region.

    Specific time periods should be defined when determining prices for each tier and the resources in the respective pools should be defined in purchase contracts for each block of power. It is envisioned that Tiers would be time differentiated. For example, all resources purchased after the initial allocation of Tier 1 that occur in a 5 or 10 year period would comprise Tier 2. The next 5-10 year period acquisitions would comprise Tier 3, and so on.

    Stability of the first tier price is crucial. BPA must be accountable for costs - customers must have the right to audit cost accounting.

12. BPA rate design shall depend on the resource and load characteristics in each tier.

13. BPA's resource acquisitions shall be based solely upon reasonable notice from the customers.

14. BPA's net revenue volatility shall be minimized.

15. **Unbundled services** must be available at cost, concurrent with the implementation of tiered rates, subject to public preference. BPA should provide unbundled services of load shaping, dispatch, marketing, reserves, capacity, conservation, etc. on a cost basis. Preference customers will have contractual rights to these services upon reasonable notice to BPA (to initiate or terminate). These unbundled services are in addition to any Tier 1 allocation.

    It is envisioned that the Tier 1 allocation will consist of capacity and energy and will be priced to include the cost of all services required to deliver the Tier 1 product. In this

way, the individual capacity and energy price components will be melded (on a regional basis) so to include the services.

BPA should assign costs of services associated with Tier 1 demand and energy rates *after* un-bundling, so that costs of surplus services are not associated with the first tier.

The customers must be assured an adequate allocation of services to deliver the allocated power. If there remains an excess of services in Tier 1, revenues from sales of those services, should flow back to Tier 1.

It is suggested that surplus services could be allocated to later Tiers, and that revenue would then be fixed to those Tiers.

BPA will then deliver power to each utility at a melded rate for energy and a melded rate for capacity. The costs to deliver power are included in the melded rates and are based on a cost accounting of all services needed to deliver the Tier 1 power. BPA's remaining costs are then charged to the remaining tiers and/or charged on a "fee-for-service" basis to anyone using separate services, (i.e. transmission).

It should be noted that tiers may need to be established for the unbundled services, when surpluses are exhausted, and the marginal cost is faced.

16. Access to Federal transmission must be available at cost, concurrent with implementation of tiered rates, subject to public preference. Priority access for conservation transactions is suggested.

17. Service to the **DSIs** should determined *after* the preference allocation is made. The initial service level for the DSIs should either be based on the most current operating year or the most recent year of load/resource balance. As the allocation for publics decreases through time, the DSI allocation should decrease proportionately.

    The DSIs must give a firm commitment to load in return for any initial service from Tier 1 power. The DSIs must agree to a take or pay obligation for the first three quartiles, with the top quartile served on a completely interruptible basis. The top quartile would be priced to reflect its interruptible character. These changes would put the DSIs on a more equivalent basis regarding the allocation and rate for FBS power.

    The allocation to publics is fixed and should not grow at the expense of the DSIs. On the other hand, if the FBS dwindles, then the top quartile of DSI contract could be used to

supplement the FBS for continued bad water years (worse flows than critical) for example.

18. **Pooling of allocations**. Utilities should be allowed to pool their allocations of power. Sales from the pooled allocations could then be made to those utilities forming the pool.

    SUB believes that pooling resources among preference customers in both tiers should be encouraged and sales from the pooled allocations can be made to other Northwest *preference* customers outside the pool. However, there should be no marketing of Federal power for profit or re-sale.

    Allocations of FBS power go with mergers of publics. Allocations of FBS power are redistributed among public preference customers when publics are acquired by privates.

19. Revenues from sales of secondary energy (and other services) must stay in the relevant resource pool. If there is a surplus of first tier energy or capacity, BPA will make it available to preference customers first. Any remaining surpluses can be marketed. All revenue to flow back to the first tier.

20. SUB believes there should be **no FBS replacements**. Freeze the current size in aMW, based on (average water year) actual operations. Tier 1 may diminish/fluctuate in size due to weather, fish, age of facilities, repayment reform, private acquisition of publics, dissolution of DSI . . . Reductions/Increases would be allocated equally among preference customers.

    All new resources or replacements to the FBS (and their associated services) will make up Tiers 2, 3, 4, etc.

21. SUB supports **take or pay contracts**, subject to notice provisions, for all tiers and all parties. However, adequate price control mechanisms must be established so that BPA can not raise rates beyond what is reasonable. This take or pay provision would only be instituted in conjunction with the ability to pool allocations among customers and the customers' right to audit BPA costs.

22. SUB supports classification of **conservation as an unbundled service**, not associated with an allocation of Tiered capacity and energy. Fundamental to this premise is that Conservation should be viewed as a resource similar to generation. In addition, Conservation should be given a priority status (as defined in the Act) when BPA acquires resources for the various Tiers.

Utilities should be able to **purchase** 'Conservation Services' from BPA for a fully allocated price (average millage per sector program). The utility would pay a nominal millage either a) in the first year only (reflecting the estimated conservation value over the life of the resource), or b) annually, over the length of conservation resource life. In exchange for this fee, BPA would deliver conservation services via an ESCO to the utility. The utility (or other utilities) could bid on a competitive basis to provide ESCO services.

a) Existing BPA Conservation Contracts should be included in Tier 1 expenses. All new commitments should be resource acquisition purchases under competitive bids on par with generation resources, in accordance with priorities of the Act (10% selection priority). Utilities would sell conservation to the Region, as firm commitments for new load are placed on BPA.

b) No further regionalization of conservation acquisitions. If utilities wish for BPA to fund conservation, at the region's expense, they must be willing to surrender an equivalent portion of their Tier 1 allocation (BPA is then free to market this allocation to the highest bidder for the life of the conservation to cover the costs of conservation offered - no negative impact to other Tier 1 purchasers).

   Major NW utilities are requesting a Transition Funding Period (current through complete implementation of Tiered Rates - FY97) that would allow BPA to continue current funding for Conservation so that these utilities who have staffed up can bridge the gap from regionalized to individual conservation funding.

c) BPA should allow an active conservation market; encourage regional stability in conservation efforts and markets; enable utilities to have the ability to control conservation programs, their costs and risks; honor contracts as firm commitments.

Mr. DEFAZIO. Clearly we have some discussion that could perhaps take place on the panel, some varying views on a number of issues.

Mr. Carr, in talking about transition, you think that BPA should assume common carrier status. I was a little curious how you envision this working. How do you reimburse someone for lost opportunity costs, seasonal exchanges, which could be displaced for their contracted load, for their preference customers? I mean we are just going to open this up to highest price bidders, is that the idea?

Mr. CARR. No, I guess that was not my vision. I think it is more along the lines of looking at what is needed in a competitive marketplace. The basic thing that is needed is for customers to have the same ability to get transmission access from Bonneville at the same price Bonneville would provide itself, to basically integrate a new resource into a load. Let me just take a simple example——

Mr. DEFAZIO. I get it, I get it. That leads to another question. We have had some discussion of the value of reserves, the variable rate, somewhat critical, and we may get into that. The question would be, given that viewpoint that everybody should have the same access as BPA has to put its own load on, on the one hand you are getting a preferred rate over here from BPA and on the other hand you want to be able to access their system so that you can go out elsewhere and see if you can find someone else to provide interruptible power or whatever else, at a slightly lower rate. You know, it just seems to me those things are kind of at cross purposes. One is a very free market approach and the other seems to me to be a subsidy approach. Now how do you reconcile those two views? I have got a problem with that. I mean, on the one hand you are exposing BPA, I think, to great risks. I have some grave concerns about some of this access, and what it could means in terms of hurting us for seasonal exchanges and things like that. And on the other hand, in fact in your testimony you suggest that we should have an even lower floor on the variable rate. You know I have written a letter to the President asking that, with a whole wide range of metals, he begin to deal with by dumping Russia. Unless we do something about Russia, aluminum prices are not going up until they fall apart over there, because it does not cost them anything to produce it. They have no market economy.

Mr. CARR. Let me take them one at a time.

Mr. DEFAZIO. Sure.

Mr. CARR. My sense on the Russian situation is that we are going to see over-production from the old Soviet Union republics for a long time to come. It is going to take a long time for their demand internally to equal their current supply capability on aluminum. We are going to see in an international market sense, it is about like having another smelter or two out there producing—or a brand new smelter to come on line that would cause supply to be greater than demand. But there are two sides to the equation. The other one is demand, and I guess my sense is that over the next several years—at least I am hopeful—we will see the other industrialized countries' economies picking up and demand picking up there. That, coupled with the U.S. economy hopefully moving ahead, will cause demand increase enough to eat into and really make up for all that oversupply.

Mr. DEFAZIO. The question is how long does that take and how long do the Northwest ratepayers eat it and how long before we get to a point under the current system where we cross that line. Under your proposal, if we drop it even lower in the short term for the floor, I mean it seems to me it would take even longer into the future before we recoup that investment.

Mr. CARR. But I certainly was not arguing for dropping the floor now. What I was saying is that come 1996 the variable rate ought to be put on the table and it ought to be a bilateral discussion. My thinking is that there probably are some changes in the variable rate going both ways—some that benefit Bonneville's other customers, some that make the variable rate better for industry—that has everybody come out in a win-win situation. I certainly would not argue for it being a subsidy; I do not think it is a subsidy now. In fact, you know, I cannot help but observe that 3 years ago when the variable rate was 6 mills above the IP rates and the companies were paying $10–15 million more a month than they would have under the IP rate, I did not hear anybody else out there arguing that the DSIs were subsidizing the public utilities, and by gosh that ought to stop right now. Things have turned around.

Mr. DEFAZIO. No, but I can give you some other example. I think my lumber and wood products folks would like to be able to get onto a variable rate. I think Dow over in Springfield would like to get onto a variable rate. They are having the same problems in the international market that the aluminum companies are. I think Teledyne would like to get onto a variable rate. I think Ormet would like to get onto a variable rate. Probably Boeing would like to get on a variable rate.

I think all the IPs would like to, and the question is, you know, at this point, in those discussions then maybe we should open up this idea to all industrial consumers and large loads as opposed to just one particular segment of the industry.

Mr. CARR. I guess from my standpoint, I am not willing to prejudge it. I think a lot of people are taking positions—not a lot—some people are taking positions on the variable rate as if it is a unilateral negotiation, that it is just a thumbs up or thumbs down by Bonneville. I guess I look at it as a bilateral negotiation. It has to be good for us before we are going to sign up for it, and it had better be good for the customers for them to sign up for it starting in 1996. And I would make the same argument under the value reserves. Some people are talking about almost negotiating positions where, as if it is a unilateral decision on Bonneville's part, only $20 million, only $10 million. My recommendation is we open up the marketplace and make it a bilateral negotiation. If Bonneville's customers only want to pay $20 million, but Puget and Pacific want to get together, and for different pieces of their reserves, they are willing to pay $50 million or $100 million, so be it. I mean that is where I would have it come out. So that we put it out there in the marketplace and see what it is worth.

Mr. DEFAZIO. So that is your rationale for the transmission, why you want this new free market transmission is so that you could bid out, say, the value of reserves.

Mr. CARR. It is one of the pieces of it. My feeling is the reserves are very valuable to the federal system. They have been there for a lot of years; they make the federal system more efficient.

Mr. DEFAZIO. I know we have got the first quartile interrupted. We have got the short-term stability reserves which are an hour or something like that.

Mr. CARR. And sometimes even less. The companies are hooked close enough into the transmission system that they can actually be cut, you know, just like that.

Mr. DEFAZIO. Uh-huh.

Mr. CARR. They are about the only load that is available to do that, to shore up the transmission system that fast, because of their size. There is also forced outage reserves that allows up to three quartiles to be interrupted at any time to shore up the loss of generation. And depending upon the length of the restriction and how much is accrued over a period of time, those are available to the system.

Mr. DEFAZIO. But is this that process where you go first quartile, second quartile, and you have to notify in June that you may go into the second quartile and you have to go out and ask for voluntary curtailment? You are talking about shorter term or less predictable; as opposed to the hydro-based system problems; you are talking about outages essentially.

Mr. CARR. Well both, both. It could be a hydro-system problem. I think we ran into that with losing one of the Grand Coulee turbines about a year and a half ago, where it caused instability in the system. The loads are able to respond quickly by a cycle. They are able to respond and cut back, and they have that ability because of their electrolytic processes. I guess to follow on that path, I certainly support what Bob Myers was saying earlier. I think there are probably a lot of other reserves we have not explored as closely as we could in some sense because there has not been a market for them. But with capacity becoming much more valuable to the system, I think everybody in the system recognizes that, then we have a chance to take advantage of probably some other valued reserves. But I think the bottom line is we cannot have it as a unilateral debate. We need to talk about it in terms of competitive market, and if it is true that some of the utilities, you know, carry through, they are really the ones that decide this, and only want to pay a small amount for those reserves, and other people are willing to pay a lot more, that is where the reserves ought to flow.

Mr. DEFAZIO. Okay. Would the people who raised this issue earlier care to respond?

Mr. SCARBOROUGH. Mr. Chairman, I would like to talk about the value of reserves. This is just my understanding and research that I have had my staff do. But from my understanding, basically the components that make up how we price the value of reserve is based upon the load and based upon the interest charged that would be necessary to finance a gas turbine. Now granted the gas turbine was never, ever built and probably was never intended to be built, but it was at least a way of determining what the cost was going to be to have a plant in place.

The load at that point in time that was estimated was needed was about 1,288 megawatts and this is back in 1981. In the rate hearings in the 1993 rate case, Bonneville's people estimated that the load needed to be somewhere between 600 and 800 megawatts. At the time that the methodology was put together, the interest rate at that time was 14 percent and that currently is still what the interest rate is. That has been frozen. So what we are looking at is that (1) the load is inflated, and (2) the interest rate is way out of line. And it should have been adjusted sooner.

Mr. DEFAZIO. Well how about the idea Mr. Carr has put forward, which is if indeed it is valuable to Bonneville to have these reserves, and I think there is certainly some arguments about that, that we essentially, as we make the next rate case, put out the reserves for bid. That is, DSIs could bid on providing power in that kind of load shaping, interruptibility, whatever, to BPA, and other industries could bid. Would you think that is a way to get at this?

Mr. SCARBOROUGH. I think we need to get it back at market rates, yes. The thing that I have a concern is that we have frozen it.

Mr. DEFAZIO. Well yes, I mean that is doing it on a calculated basis for one industry. What he is proposing is a very different model, which would be, hey, if say even Boeing wants to take a risk or someone wants to take a risk, they may be able to get a discount on their power but they are taking a risk. I mean in the past, it has been more suitable for the aluminum industry because of the way pot lines work and that, but there may be other industries out there that are interested in bidding on this, and to put it out for bid, maybe you want to establish a floor value of reserves, you know, or something through the evaluation process. But instead of just fixing the value, see what the market would provide. That is an alternative.

Mr. Kittredge.

Mr. KITTREDGE. Mr. Chairman, I think Mr. Carr is representing the people that employ him very well, but I think that some of his comments are somewhat disingenuous. It is certainly true that the DSIs paid more for electricity at some point. However, every single moment of that time, they were making money for their stockholders and they were doing that from the FBS. The idea that somehow or another the transmission should be used to help them raise the value of reserves, which is essentially what he has proposed, presupposes two things. It presupposes first that the DSIs have an access right to the transmission system and it almost presupposes, I think you have to suppose in order to go along with that, that they have a footing equal with PF customers in terms of having a right to the federal-based resource in the first place.

I do not think either of those things are necessarily true and I think that that changes the basis on which Mr. Carr argues.

Mr. DEFAZIO. Okay. Mr. Carr wants to respond. Go ahead, Mr. Carr. I like it when the panel starts having a discussion and I do not have to provoke things. That is good.

Mr. CARR. Well maybe I am going to surprise you with the answer, but I am a lot more concerned about customers, the public utility customers, having access to Bonneville's transmission system, than I am about the DSIs. I want to see the situation where

if a public utility wants to acquire their own resource, they have a common carrier path opened up to them on the transmission system at a fair and equitable rate, and resource integration services provided by Bonneville at a reasonable price, so they can bring in their own resources. I want to see a competitive market out there in the new resource marketplace, and I think the current situation gets in the way of that happening. I mean, I see it every day.

Mr. DEFAZIO. Well what about BPA's social obligations, fixed costs and its base system? If we totally open up the transmission system and BPA cannot even transmit its base load or meet its mandates for preferred customers, it seems to me there have got to be some limits on this free market.

Mr. CARR. I think what I am arguing is that you lock in the vintage, whatever you want to call it, the resources, the federal based system resources with all the costs associated with them, along with the transmission access, so that——

Mr. DEFAZIO. That would have access.

Mr. CARR. That access would actually come with the allocation of the vintage system, or the tier 1. No, that is not going to get bumped; the public utilities would have transmission capability getting their existing resources that they purchased from Bonneville into their load. I am a lot more concerned about the new resource market and that is what I am focusing on.

Mr. DEFAZIO. So you are talking about the increment.

Mr. CARR. The increment and remember that Bonneville has about 80–90 percent of the high voltage transmission system, but they only have about 45 percent of the generation resources.

Mr. DEFAZIO. Mr. Shields.

Mr. SHIELDS. Yes, Mr. Chairman. There is a piece of the whole DSI issue that troubles me and it goes to what the thrust of many of my comments was, and that is this administrative lock that was put on the debate. An administrative decision was brought forward and it literally precluded any debate of the value of reserve, of the cost of the DSIs in the 1993 rate case. And I think that goes to really the heart of the matter—Bonneville has to create opportunities for itself to deal with changing times. When it comes up with administrative locks so you cannot debate these issues, I am pleased to hear Mr. Carr say he is willing to debate the issue. We should have done that two, three, four months ago during the most recent rate case. We were not able to do that and I would hope that——

Mr. DEFAZIO. But do they not have contracts until 1996?

Mr. SHIELDS. Yes.

Mr. DEFAZIO. Well then what difference would it have made in the rate case this time?

Mr. SHIELDS. Well if we did not have this lock, if we were able to debate it, maybe we could have come up with some of the ideas that Mr. Carr is putting forth here. I guess what concerns me is if we have not had the opportunity to debate the issue, we are going to defer it until 1996 or later.

Mr. DEFAZIO. Okay.

Mr. CARR. I guess just an observation, I do not think it is getting punted to 1996.

Mr. DEFAZIO. Do not think what?

Mr. CARR. I do not think the issue of the reserves, the variable rate, I do not think those are getting punted to 1996. I think those will be all part of the unbundled services that we talk about. In terms of whether you think about it from Bonneville's term, it is a marketing plan, or you think about it from the buyer's standpoint, a purchaser's plan, but that has got to be part of the whole package that goes in the new power sales contract that is offered in late 1995. I think those issues will be on the table and I think over the next year and a half to two years, that they will get a full debate, and I am looking forward to it.

Mr. DEFAZIO. Go ahead, Mr. Clayhold.

Mr. CLAYHOLD. Mr. Chairman, the concern I have about this discussion, it sounds like we are going down a track here that suggests that the FBS, or a piece of it, be put out to the highest bidder. And I think that would probably——

Mr. DEFAZIO. No, he is offering a new construct and I am trying to get other people to react to it to see where we are headed.

Mr. CLAYHOLD. I understand that. If I understood John Carr correctly, it centered around the DSI being able to market their reserves somewhere else, and I am wondering really where that reserve comes from. That is a piece of the FBS. Is there an ownership right in that, that they could just simply auction off?

Mr. DEFAZIO. How would you respond to that—he's saying that it is a piece of the FBS that you want to market essentially.

Mr. CARR. I do not think so. I guess what I am talking about marketing is the interruptibility feature of our loads, and having both a market on the supply side, which I think the Chairman was alluding to earlier from Boeing or whoever else wants to—or even a new combustion turbine, somebody—there are all kinds of ways of providing reserves. And then on the demand side, I was arguing that Bonneville should not be the unilateral buyer, we need more buyers in there. But it would not be marketing away any of the FBS; it is only the rights to restrict the DSIs' load or the reserves. Now again I said it earlier, I think those reserves are very valuable and that they are best suited to the federal system loads, but it cannot be a unilateral discussion or we are going to get to an inefficient result.

Mr. DEFAZIO. Okay.

Mr. Clayhold, a question for you. You know, I think there are a lot of arguments to be made for an irrigation rate, you know, rural communities, agriculture and that, but I have got a problem with the one key argument which you reiterated a number of times, which is the argument about the seasonality, because things have changed a little bit since the first environmental exchange agreement. Seasonal agreements were negotiated a number of years ago by then-Administrator Jura with California. We are finding that there is at this point great value in being able to provide firm power to California markets during their peaking season and to get compensated during our peaking season. So the seasonality issue I think has changed quite a bit, given that. And then there are two other corollary issues: One would be that in addition to the change in the seasonality, the other major change we are looking at is we want to keep water in the river. And if we encourage withdrawal of the water through inefficient use, then we have to make up for

it, you know, if the flow regime of the Power Council is followed, through drawdowns or in other ways of finding increased flows. So what I would posit to you is perhaps we ought to link an irrigation rate to some demonstrated best, efficient practices on the part of irrigators as opposed to just providing it blanket to all irrigators. You might respond to that.

Mr. CLAYHOLD. Well, I do not think the irrigator and irrigation utilities are afraid of that concept. In fact, it has been in practice for the last couple of years. It was a way we were able to preserve the irrigation discount, as we understand it anyway, through the 1993 rate case. Irrigators have a long history of conservation activities, mostly driven by their own costs. Certainly some of it came about because of Bonneville payments. There are a number of conservation programs being operated among the irrigators right now, and we can clearly show—and I just mentioned this briefly, but the paper talks about it a little more—we can show that there has been a decline in energy usage by the irrigators even though the irrigated agriculture has risen slightly, ever so slightly. Not much but just a little bit, and this does demonstrate then a more efficient operation on the part of the irrigators.

We also suggest in our paper that not much attention has been focused on the irrigation segment, most of it has been conservation practices along the I–5 corridor, and that is where the big stuff is I suppose. But we are talking about tiny stuff here, we are talking about irrigation withdrawals of the whole region of around 6 percent.

Mr. DEFAZIO. But some of it is in key areas. We had extensive discussion about this, particularly dealing with the Snake, yesterday in Idaho. Some of it is in very key areas.

Mr. CLAYHOLD. Yes, and I understand that issue too, it is a very sensitive issue.

The other point about the value of seasonality and the value of summer energy down in California, if we are about to get into that and if that is the way Bonneville prices its power, we are going to stand this region on its head. We are going to become the energy farm for California while our industries float down the river or dry up. I mean that is cockeyed.

Mr. DEFAZIO. No, no, but the key is that we have winter peaking needs, we have to shape the flows differently on the rivers. There are ways to meet the needs, avoid environmental problems in California; that is, firing up the thermals in areas which are restricted under the Clean Air Act, so we are meeting their environmental problems, they are meeting our environmental problems with flows. These are very beneficial exchanges which would be much more costly to obtain in other ways. If we had to get those increased flows in other ways—if you had been in Idaho yesterday, it is pretty controversial, the other ways we are looking at getting those flows, as opposed to being able to shape them with these kinds of exchanges.

Mr. CLAYHOLD. Obviously this is for a much longer discussion than we can do here. I would simply point out that we still believe that there are definite benefits to Bonneville on a cost-based approach for this unique summer load, that goes away in the winter. And you cannot escape that, it does goes away in the winter.

Mr. DEFAZIO. Okay. Mr. Piper wanted to add something.

Mr. PIPER. On the issue of the benefits of summer exchanges with Bonneville, I would submit to you that as more and more non-firm or secondary power is generated in the spring and summer months for fish flow purposes, that the California market will be less and less willing to participate in exchanges. That is, they can buy the power they need to displace the higher cost resources at dump rates as opposed to exchange rates.

Mr. DEFAZIO. It all depends on who controls the transmission, to some extent.

Mr. PIPER. Well yes, and——

Mr. DEFAZIO. If we have Mr. Carr's model, then we are going to have trouble making seasonal exchanges. There is some question there.

Mr. PIPER. It just points out the dynamics that are going on all the time.

Mr. DEFAZIO. Right. I think John thinks we are misunderstanding him, and we may well be. Go ahead.

Mr. CARR. I am not arguing for the transmission, the total transmission——

Mr. DEFAZIO. You are not arguing the Martha Hessey model of transmission, is that what you are telling me?

Mr. CARR. I do not think so. I think you end up getting the same use of the Bonneville transmission system. All I am saying is if you have a utility that is faced with the decision of purchasing their own resource from an IPP or a consortium, and they decide to meet their load growth with that, that they should have access to the Bonneville transmission system at a fair and equitable price to get it in, just as if Bonneville had met that load growth with their own resource and transmitted it in there. You ought to end up getting the same amount of use of the Bonneville transmission system going to serve the same amount of load; it is just who builds the resource. So it should not change the ability of Bonneville to make seasonal exchanges or any of those things, which I think all of us feel——

Mr. DEFAZIO. Well I am not closing the door; there are some interesting things. There is just the recently highly publicized installation of the new switching devices. I mean if we can actually transmit more power at what is a substantial capital investment, but still we can do it without the extraordinary capital investment of entirely new transmission corridors, which are very problematic at this point in time, then maybe, getting back the full cost of the investment or maybe having the third-party financing discussions we have had with utilities elsewhere, maybe BPA does not have to up front those things and consortiums of utilities can look at up fronting and then they can get rights to the increased transmission. There is a whole new world out there. I just want to make sure we do not destroy the one we have, as we head toward the new one. That is my concern.

Since we have three public utilities represented, the earlier discussion that I had about a requirement on public utilities for some sort of least-cost planning, do you have any concerns about that, do you understand my concern about the potential or the possibility there, and what I am trying to get at? Do you have another way

of getting at it? How would you assure me on this issue, Mr. Shields?

Mr. SHIELDS. We submitted comments before this hearing and also one on July 12 addressing least-cost planning. I guess the first distinction I would like to draw is the difference between least-cost planning and least-cost acquisition. You can have regional planning, which I think is the value of the least-cost planning models that the few of us in public utilities that have least-cost planning believe that you do not want to get away from centralized planning. I think the Council's role is a vital role. I think we need a least-cost plan. I also think though that you can have decentralized acquisitions of resources and have a least-cost planning process where such as Emerald, who has a least-cost plan, submits that through a review process to ensure that there is consistency with the regional goal. And I think you can get there.

Mr. DEFAZIO. But that does not happen.

Mr. SHIELDS. It does not happen, no, but I think the institutions are in place to see that happen. I do not think you need to create a new wheel—maybe you need to clean a few spokes.

Mr. DEFAZIO. Okay, so you would say basically a review for consistency much like what BPA has to do now in dealing with the Council, theoretically.

Mr. SHIELDS. Theoretically, yes.

Mr. DEFAZIO. Right, okay. Mr. Scarborough, do you want to comment on this?

Mr. SCARBOROUGH. Mr. Chairman, no. We have not really even discussed or talked about that issue to be prepared to talk about it.

Mr. DEFAZIO. Okay, that is fine. Mr. Kittredge.

Mr. KITTREDGE. Mr. Chairman, the Springfield Utility Board supports least-cost planning. We believe that consistency with the Council's plan needs to be part and parcel of the new unbundled, tiered-rates world, and we think that least-cost plans that are reviewed for consistency by the Council, if a utility chooses to go forward with a resource that does not meet that review standard, they would certainly be free to do so. But we think that in doing so, they should reduce their tier 1 allocation by the same amount. That way, the region is held harmless for their decision, and we get the accountability that SUB feels is lacking under the current system.

Mr. DEFAZIO. So they would have essentially a permanent, voluntary ceding of the tier 1. How would you redistribute the tier 1?

Mr. KITTREDGE. The tier 1 would be redistributed, a portion through the tier 1 ratepayers, or tier 1 customers.

Mr. DEFAZIO. Proportionately?

Mr. KITTREDGE. That is correct. As would any reduction or increase. For instance, if the fish flow requirements were to lower the capacity of the system to produce tier 1 resources, then some proportional decrease would be passed through.

Mr. DEFAZIO. Do you have any reflections on that, Mr. Clayhold?

Mr. CLAYHOLD. Least-cost planning came up a couple of years ago in the State legislature I believe in Washington State, and the PUDs committed to the concept of least-cost planning. It was not embedded in the state law, however. We encouraged it not to be. I am troubled with this—not the least-cost planning, I think it is

the absolutely smart thing to do, I doubt if anybody would argue with that. What I am troubled about is we continually get into discussions from time to time about how much control and regulation is placed on a local public utility, whether it is a municipal or whether it is a PUD or whether it is a co-op. We stave off the PUC whenever an IOU or a customer of IOU runs to the legislature and tries to get us brought under the PUC. I worry that this is an inroad to make us all alike, and there is a value in our diversity and there is a value in the fact that we are locally controlled. It is not an argument against least-cost planning and it is not an argument against a requirement for least-cost planning, but I worry about this business of superimposing by some central agency, that it gets us one step closer to losing our ability to locally control.

Mr. DEFAZIO. I will respond. I think you are making a valid point. My concern is the lack of this is leading to making us all alike in terms of new acquisitions. Look down the list, gas, gas, gas, gas, gas, gas, gas, gas. I am concerned that the lack of some sort of direction is leading us to becoming all alike because of perceived current market conditions, and I am just not quite as sanguine about the future of that as maybe some others are. Whenever something becomes a conventional wisdom and everyone is doing it, then it is time I think to begin thinking about it.

Yes, Mr. Piper.

Mr. PIPER. I do not think it is all gas, gas, gas, gas.

Mr. DEFAZIO. Well, I see everybody is out with bids and the bids come back. Most of the bids are gas and then they say, well, now, in the second stage 95 percent of what we are looking at will be gas and we will look at one wind power and we will look at one demand-side and we will look at one this, you know.

Mr. PIPER. But the only resources that have been committed to have been by Bonneville at this point.

Mr. DEFAZIO. No, I know, but I just keep reading about where people are at in terms of——

Mr. PIPER. I understand.

Mr. DEFAZIO. Right.

Mr. PIPER. But I would not take that as being fact. The other thing I would suggest to you is we are all going to do least-cost planning. I do not think there is any question about it, and there is nothing new with least-cost planning except the definition and the formality of it. It has been the way things have been done historically. Now maybe all of the factors have not been considered in original earlier least-cost planning, but nonetheless we are all going to be doing it. My only hope is that as and if to the extent these things are centralized, that we do not get whipsawed, whipsawed by in our case federal administrative requirements by REA or in siting requirements by any of the state siting agencies.

Mr. DEFAZIO. Right, the desirable end is not to build in more bureaucracy, but to continue to meet the coordinated regional goal. Ideally what we would do is magically get to our coordinated regional goals without any imposition of a central big fist, but I am not idealistic enough to think that is going to happen. But there may be better ways to do it than even through the Council, I do not know.

Mr. Shields.

Mr. SHIELDS. You may find a model in Western Area Power Administration for accomplishing exactly that.

Mr. DEFAZIO. You mean the stuff I wrote in there?

Mr. SHIELDS. Yes, congratulations.

Mr. DEFAZIO. I have to tell you, I heard an awful lot of arguments I heard earlier today last year.

Mr. SHIELDS. Right. Well I would encourage you to go back and look at your——

Mr. DEFAZIO. So you think I did good, huh? OK, well I have still got copies of that. Good staff work.

Mr. KITTREDGE. Mr. Chairman, I do not think the mandate for least-cost planning—as an elected official, I think I am as conscious as Don is about the prerogatives of the local utilities, and at least what we are suggesting at SUB is that the review of the least-cost plan for compliance or non-compliance is not a note from on high from the Council of what can or cannot be done. What it does say is that, if you make the decision to go without the plan, then you are in a situation where you have the responsibility for your decisions. And I think that is——

Mr. DEFAZIO. That is an interesting model. I think there are a number of interesting things to look at here, some that can be market-driven—there are different ways to approach it.

This has been very helpful to me. Does anyone feel they had something they wanted to say they did not get to say?

[No response.]

Mr. DEFAZIO. If not, I am going to thank you for your participation, thank everybody. I think this was a tremendously helpful hearing, and the task force is now adjourned.

[Whereupon, at 2:45 p.m., the task force was adjourned.]

APPENDIX

SEPTEMBER 25, 1993

ADDITIONAL MATERIAL SUBMITTED FOR THE HEARING RECORD

PAUL G. LORENZINI
President

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PACIFIC POWER

October 22, 1993

The Honorable Larry LaRocco
United States House of Representatives
1117 Longworth House Office Building
Washington, D.C. 20515-1201

Dear Congressman LaRocco:

This letter responds to your request to me during the September 25 hearing for further information about BPA's funding of regional fish and wildlife programs. I commented that the investments BPA is making in fish and wildlife programs could be targeted more effectively to meet statutory requirements.

As you know, BPA is responsible for funding fish and wildlife measures to mitigate for the impacts of the Federal Columbia River Power System (FCRPS). In 1993, for example, BPA spent over $150 million in foregone revenues and power purchase costs to provide increased river flows for fish. We are concerned, however, that BPA also is funding costly fish and wildlife programs and measures that are not related to the development or operation of the federal hydropower system or could conflict with its other statutory obligations.

Here are some examples:

- BPA has spent $57 million to date to underwrite habitat enhancement projects throughout the Columbia Basin to mitigate for the impacts of land management activities including forestry, grazing, and irrigation. Annual operation and maintenance costs for these projects add about $3.5 million to BPA's budget.

  While many of these are undoubtedly good projects that benefit fish, they are aimed at mitigating activities other than hydro operations. They are clearly <u>not</u> BPA's responsibility. In fact, in its recent function-by-function review, BPA concluded that: "Within BPA's Fish and Wildlife Program... about two dollars is spent for offsite enhancement for each dollar spent to understand or rectify the adverse effects of the Federal Columbia River Power System."

- To date, BPA has spent $10 million to fund an enforcement program to help reduce illegal salmon harvest. While this program benefits salmon stocks, this law enforcement responsibility belongs with state fishery resource managers. Illegal salmon harvests are not connected to or caused by federal hydro system operations.

The Honorable Larry LaRocco
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- In addition, BPA is making significant financial investments (over $48 million to date) in new salmon and steelhead hatcheries in the basin. Examples include the Northeast Oregon, Yakima, and Umatilla hatcheries. These large-scale hatcheries could adversely affect salmon stocks listed under the Endangered Species Act (ESA). BPA could more effectively meet its ESA obligation and better target its investment by first determining the impact these hatcheries may have on listed stocks -- before proceeding with design and construction.

- Similar problems now threaten to crop up for resident fish and wildlife programs. I have enclosed a copy of a Pacific Northwest Utilities Conference Committee letter that highlights some of these same concerns with respect to the Power Planning Council's Phase IV amendments for resident fish and wildlife.

Even BPA admits its priorities are skewed, as evidenced by this statement in the Executive Summary of its function-by-function review: "Fish and wildlife mitigation for the FCRPS is largely planned and implemented in the region based on program inputs -- dollars, coordination processes, regional agreements, and organizational issues, rather than program outputs -- expected fish and wildlife saved or produced."

We believe that to rectify that situation, BPA and the Power Council must establish clear biological goals and objectives for its fish and wildlife programs and prioritize program activities. BPA also should hold the state fish agencies and tribes accountable for producing measurable results with the BPA funds they receive. The Task Force could serve the region well by pursuing a more in-depth scrutiny of BPA's fish and wildlife expenditures.

I hope you find this information helpful.

Sincerely,

Paul L. Joreyquin

Enclosure

c w/encl.: Congressman Peter A. DeFazio
Ms. Linda Stevens,
House Committee on Natural Resources

PNUCC

PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE

August 13, 1993

Mr. Stephen L. Crow
Northwest Power Planning Council
851 SW 6th Avenue, #1100
Portland, Oregon 97204-1348

Dear Mr. Crow:

PNUCC appreciates the opportunity to comment on the proposed Phase IV Resident Fish and Wildlife Amendments. Phase IV gives the region a unique opportunity to carefully evaluate the scope and direction of the program as a whole. We are providing comments on the "big picture" as well as on individual measures.

When we looked at the "big picture," we found there were several overriding issues which must be addressed before the program can be truly successful. Throughout the last decade, you have consistently promoted the principles of adaptive management. Now it is time to apply these principles to your program.

In other words, we ask the Council to "Just Say Whoa!"

★ **Defer final rulemaking on Phase IV** until the region has resolved the fundamental questions and issues raised by the Scientific Review Group in the Critical Uncertainties Paper and has developed biologically sound program goals with measurable objectives.

★ **Proceed with caution.** Make essential programmatic decisions and then ask the Bonneville Power Administration (BPA) to fund only those measures which meet the region's overall goals and priorities and which directly address hydropower-related losses.

★ **Require biological and fiscal responsibility and accountability** in all aspects of the program.

★ **Delete all of the Resident Fish implementation projects from Phase IV.** When you wrote the draft wildlife section, you made a conscious decision to limit Phase IV wildlife amendments to policy issues. We agree with the decision and ask that you demonstrate the same leadership in the resident fish amendments. Please ask BPA to use the Implementation Planning Process (IPP) to carefully evaluate the technical merits and the applicability to the overall program goals of all of the existing and new resident fish and wildlife project proposals.

We are not asking you to stop the program or to stop funding what is already in the program. We are asking you to make some critical programmatic decisions before you add more projects. And, we are asking you to stick with the process developed by BPA and CBFWA -- the Implementation Planning Process.

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Mr. Crow
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We question the value -- to the resource, to the region and to the ratepayers -- of forging blindly ahead with Phase IV. Phase IV will cost between 500 Million and 1.5 Billion dollars. BPA is facing a 14-16 percent rate increase and a 20 percent reduction in budget. BPA can't pay for the projects already in the program and will not be able to fund new projects until FY 1996.

This is your opportunity to apply adaptive management to the program without delaying implementation. Please take the time now to build a conceptual foundation and to thoroughly evaluate the program goals and priorities. Draw a clear map of where you want to go and how you will know when you get there. Then, when funds are available in FY 1996, the region will be in a good position to choose the most biologically sound and cost-effective fish and wildlife projects.

Please consider the following:

★ **The Council has proposed a number of measures which exceed its authority and/or do not address a documented federal hydropower-related loss.** The Northwest Power Act requires that the ratepayers shall pay for fish and wildlife mitigation only to the extent affected by federal hydropower development. This definitely precludes any mitigation for -- or studies of -- losses above FERC-licensed projects. It also does not allow mitigation for cultural losses. Further, the "in lieu of" clause in the Act [Section 4(h)(10)(A)] and Section 4(h)(8)(C) prevent the Council from intruding in the congressionally-authorized Lower Snake Compensation Plan.

The measures proposing U.S. ratepayer-funded studies and mitigation in Canada are the most glaring examples of where the Council has gone beyond its authority. We strongly oppose these measures. Mitigation in Canada is clearly outside the Council's authority and is illegal. The Council cannot obligate U.S. dollars to Canadian interests. Only Congress can do this. Congress specifically limited the Council's jurisdiction. The Council is to develop a regional plan. Section 3(14)(A) of the Act defines the region as "the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin." This definition cannot be construed in any way to include any portion of Canada.

★ **The Council's Fish and Wildlife Program is not founded on a clear statement of how the major biological and physical components of the Columbia River ecosystem (headwaters, mainstem, estuary, ocean) fit together.** In other words, it lacks a conceptual foundation and is based on questionable assumptions. We, as a region, do not have a clear idea of where we want to go, how we will get there, and whether what we are proposing will get us there.

★ **The Council wants to build its program on the "ecosystem approach," but the proposed amendments ensure that can't happen.** For example, the measures which allow or promote mitigation for resident fish losses caused by anadromous fish mitigation violate the whole concept of "ecosystems." Other measures focus on managing or mitigating for a single species instead of looking at how the aquatic and terrestrial communities function as a whole. Still other measures promote put-and-take-fisheries strictly for harvest or recreational purposes which could adversely impact sensitive species. Further, allowing passage beyond natural barriers will create havoc in the existing ecosystem and could be grounds for future ESA actions.

Mr. Crow
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★ **The proposed implementation projects have not been screened, prioritized, or subjected to a rigorous public scrutiny. The Council should build a program and then look for the most appropriate projects, NOT adopt a large number of projects and then try to build a program around them.** BPA and the Council have developed a clear separation of responsibility -- the Council addresses policy: BPA's IPP deals with specific mitigation projects. The current draft amendment document includes a large number of resident fish implementation projects which should be handled through the IPP, not in Phase IV.

★ **There are no resident fish or wildlife emergencies which require Council action.** The Fish and Wildlife Service, under the auspices of the Endangered Species Act, now has responsibility for bull trout and sturgeon. Further, there are projects already in the pipeline which benefit resident fish and wildlife in all four states.

★ **The draft amendment document lacks accountability and fiscal responsibility.** The measures which direct BPA to enter into wildlife mitigation trust agreements where the implementor bears no financial responsibility demonstrate a total lack of accountability and business sense. You have guaranteed that the Fish and Wildlife Program will become an entitlement program. Under the proposed measure, the implementors can (and will) "just take the money and run." At the end of the agreement period, the ratepayers will have nothing to show for their investment and the resource will be no better off. If you are truly interested in protecting, mitigating, and enhancing fish and wildlife in the Columbia Basin, you will <u>require strict biological and fiscal accountability.</u>

Another measure suggesting a funding level (15 percent of the budget) for resident fish and wildlife mitigation is arbitrary and devoid of science or reason. It also looks very much like an entitlement program. Funding for the program should be tied directly to ratepayer responsibility and to the biological need. The region should establish a clear mitigation goal and keep accurate track of the progress toward that goal. BPA should stop funding resident fish and wildlife projects when we have reached the goal.

★ **It is fiscally irresponsible to use changes in reservoir operations as a mitigation tool for resident fish.** A number of measures limit reservoir fluctuations and therefore limit the reliability and flexibility of the hydrosystem. Section 4(h)(5) of the Act requires the Council to protect, mitigate and enhance fish and wildlife while "assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply." In addition, Section 4(h)(6)(C) requires the Council to "utilize, where equally effective alternate means of achieving the same sound biological objective exist, the alternative with the minimum economic cost." In real terms, these two sections prohibit using changes in reservoir operations as a mitigation tool.

The measure calling for Biological Rule Curves (BRCs) is particularly disturbing. The concept of, and reservoir elevations for, the BRCs have been continuously evolving through SOR and during Phase IV. Final numbers are still not available. If Montana Fish, Wildlife and Parks cannot define the rule curves, then they cannot analyze them- and neither can the Council. The Council should NOT automatically adopt a nebulous concept just because it was proposed. We suggest that the Council defer any decision on the BRCs until the SOR is complete and until the region has thoroughly evaluated 1) the objectives of the BRCs 2) alternative means of

achieving the same biological objectives and 3) the regional environmental and power impacts of the curves (including the emissions and hazards of replacement energy sources).

In addition to commenting on the overall scope and direction of Phase IV, we provide the attached issue matrix which outlines the proposed measures and our position.

In conclusion, we again urge you take a hard look at the resident fish and wildlife amendments. Use the next two years to resolve the outstanding questions and to build a solid conceptual framework. Take the time to clearly define the hydropower responsibility, and to thoroughly evaluate the biological need and scientific soundness of the existing and proposed projects. By FY 1996, when BPA is able to implement new projects, you will have developed a biologically sound, fiscally responsible program that will truly benefit the fish and wildlife of the Columbia Basin.

Thank you for the opportunity to comment. We look forward to working with you in developing a solid conceptual framework which will lead to the world-class fish and wildlife program that you envision.

Sincerely,

Al Wright
Executive Director

Attachment

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
	Wildlife	
10.1	**Goal: To achieve and sustain levels of habitat productivity in order to fully mitigate for the wildlife losses that have resulted from the construction and operation of the federal hydroelectric system.**	Oppose. This violates the ecosystem approach. In a true ecosystem, habitat productivity is very dynamic and rises and falls according to the stage of succession. The Act specifically stated that full mitigation was not required.
10.2A	**Use the loss estimates as a starting point for developing wildlife agreements.**	Oppose.. The independent auditor found that the loss assessments, taken as a group, were inconsistent and needed considerable work. It doesn't make sense to base negotiations on flawed data. Use acres inundated as the basis for negotiations.
10.2B1	**Allocate wildlife mitigation expenditures to the various project purposes.**	Use Joint Capital Costs.
10.2B2	**Coordinate mitigation for hydropower-related losses with mitigation for non-hydro losses.**	Support.
10.2C	**Definition of mitigation**	Oppose. Congress intentionally did not define mitigation. Also, this definition requires restoration which Congress specifically said was not required.
10.2D	**Inundation Loss Assessments for Roza, Chandler, Deadwood and Cascade.**	Oppose. Cascade and Deadwood do not have any hydro allocation. Roza and Chandler did not inundate any land and were not authorized for power production.
10.2E	**Criteria for mitigation plans and projects.**	Oppose criteria which specify that mitigation be based on habitat units, which allow mitigation for societal and/or cultural losses, and which allow the agencies and tribes to veto proposals submitted by independent groups.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
10.2F	**Develop a mitigation crediting system.**	Use PNUCC's wildlife crediting and accounting system (Wildlife Amendment RF4-0113A-F). Oppose using habitat units as the mitigation currency, support credit for fish habitat improvement projects.
10.2G	**Operational Loss Assessments**	Oppose. Mitigation for inundation losses includes reservoir operations. Mitigate only for free flowing reaches below federal projects. Defer loss assessments until SOR is complete.
10.3A1	**Short-term Agreements** Idaho & Oregon.	Oppose. Don't waste time and money on short-term agreements.
10.3A3	**Long-term Agreements - Inundation**	Support. Negotiate long-term agreements now.
10.3A3a	**Criteria for Long-term Agreements.** (No financial liability for the agencies and tribes).	Oppose. No indemnification; no agreements. The implementors must be accountable. See comments in the attached cover letter.
10.41&2 Section 7 2.	**Monitoring & Evaluation, biennial report & Independent Scientific Group review.** Impose a ceiling of 20 percent of the budget.	Base monitoring on easily measured objectives geared to biologically achievable goals.
10.5.1	**Lower Snake Compensation Plan.** Pay the Nez Perce Tribe to participate.	Oppose. The tribe should ask BIA for money to participate. This is an issue between the Corps, the Tribe and Congress. It is not BPA's responsibility. The Council has no jurisdiction over the Lower Snake Compensation Plan.
10.5.2	**Determine whether Lower Snake Compensation Plan fully mitigates the losses.**	Oppose. Beyond the Council's authority.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
Cover Letter 2.2B	**Cultural Loss Assessments.**	Oppose. This is beyond the authority of Council. The Act directs BPA to mitigate for fish and wildlife losses, NOT for cultural losses.
	Resident Fish	
2.2B1	**Develop a method to identify conflicts and assess tradeoffs between and among program measures and basin activities.** Examples: between and among fish and wildlife; between hydropower, irrigation, flood control.	Oppose mitigation for mitigation actions. Conflicting measures should not be adopted. Oppose mitigating for cultural losses.
2.2C	**Develop criteria for evaluating proposals for providing passage at natural barriers.**	Oppose. Providing passage alters natural ecosystems. Criteria and processes waste time and money. Sets stage for future litigation.
2.2D1	**Develop and implement a Water Budget accounting system.**	Not a Council function. This is now the responsibility of the four federal agencies under the ESA.
2.2D4	**Fund measures that address reservoir operations including BRCs and operational mitigation.**	Oppose. Don't use reservoir operations as a mitigation tool. There are other equally biologically effective ways to enhance resident fish. See comments in the attached cover letter.
Section 7 2.	**Monitoring and Evaluation not to exceed 20 percent of budget.**	Not based on science and not related to needs of project, ecosystem, or target species. M & E should ensure accountability.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.1	**Resident Fish Goal**	Support Option 2 with the following changes to the first two sentences: The program goal for resident fish is to protect, mitigate, and enhance native resident fish to the extent these ~~stocks~~ species are affected by the development and operation ~~at each hydropower facility~~ of the federal hydropower system. This goal will take into account the difference between losses, ~~and~~ increases, and existing mitigation (net change) at each project to determine whether losses have occurred. This option is most consistent with the Act's mandate to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of the federal hydropower system. The focus on native fish must take precedence at this time to assure that others do not become candidates for ESA listing. Resident fish goals and priorities should be developed in the context of the conceptual framework to ensure that they are compatible with anadromous fish and wildlife goals.
9.1(1)	**Complete Loss Assessments at each hydropower facility throughout the Columbia River Basin.**	Oppose. Don't waste more money on loss assessments. Enhance habitat instead. Negotiate a Resident Fish Agreement. The Act does not require full mitigation, i.e. restoration.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.2A	**Resident Fish Priorities**	Support Option 1 because of its emphasis on weak native stocks, with changes to the following sentences: Sentence 2: These priorities should be fully considered in addressing native resident fish losses related to development and operation of the federal hydropower system. Point 3:-Accord ~~resident fish~~ projects that benefit multiple native resident fish species and/or also provide benefits for wildlife and anadromous fish high priority. Delete points 2 and 4, which accord priority to areas without resident fish and to "important fisheries." These are economic priorities which do not reflect biological need or federal hydropower system impacts. The Fish and Wildlife Program is designed to protect, mitigate, and enhance fish and wildlife, not people. It should not be harvest driven.
9.2B	**Natural and artificial propagation.** Use anadromous fish process, criteria and guidelines.	Support hatchery review. Include a review of costs and biological effectiveness.
9.2C	**Implement Section 6.5 Model Watershed Management.**	Support the concept, implementation must be based on clear and enforceable management plans.
9.2D	**15 percent of BPA Fish and Wildlife Budget allocated to resident fish.**	Spending target is arbitrary, excessive, and not biologically based.
9.2D	**Prioritize Resident Fish Projects.**	IPP, not Council, ranks projects.
9.2E	**Study and mitigate for transboundary stocks.** U.S. funding in proportion to U.S. benefits.	Strongly oppose. This is clearly beyond the authority of the Council and the Act and is illegal. Requires an international treaty. See comments in the attached cover letter.
9.3A4	**Submit loss assessments and mitigation plan for Kerr Dam.**	Oppose. This is FERC Project. BPA can not mitigate for non-federal projects.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.3A10	**Study effects of anadromous fish measures on resident fish in the Snake River.**	Oppose mitigation for mitigation. Fish management agencies advocating drawdown and increased flows for anadromous fish must accept the consequences of their actions.
9.3A11	**Study effect of reservoir management on Lake Pend Oreille kokanee.**	Need to thoroughly assess other causes of the kokanee decline. For example *Mysis* shrimp competition, harvest practices, predator stocking (rainbow trout), predator/prey interactions, and hatchery practices all affect kokanee survival. Also need to evaluate alternative means of increasing the kokanee population such as improving habitat quality and hatchery practices. BPA constructed the Cabinet Gorge Hatchery to address factors limiting spawning success and egg survival. Poor survival at other life stages may now be limiting and may not be related to reservoir operations.
9.3B2 9.3C	**Biological Rule Curves (BRCs) for Libby and Hungry Horse dams.**	Oppose. Should be withdrawn. Final numbers are not available and it is not possible to accurately evaluate this measure. See comments in the attached cover letter.
9.3B3 9.3C4	**Immediately mitigate at Hungry Horse and Libby if BRCs are exceeded for power purposes.**	Unrealistic. Immediate mitigation is not possible.
9.3B15	**Instream flow study on the Flathead River.**	Should not duplicate existing research. Hungry Horse Mitigation Plan covers all mitigation for Hungry Horse Dam. Program amendments should merely reflect the plan, not add new measures. According to the Hungry Horse Implementation Plan, "operational mitigation was deferred for consideration under SOR."
9.3C6	**Add three generators to Libby.**	Support.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.3D5	**Dworshak kokanee and westslope cutthroat trout studies-** analyze methods to minimize entrainment, mid-winter trawling to determine kokanee densities, annual kokanee spawner counts, genetic inventory of westslope cutthroat trout -- emphasis on genetic introgression by introduced rainbow trout.	Oppose. Dworshak is operated for anadromous fish -- This measure suggests mitigation for mitigation. IDFG and Nez Perce Tribe just completed BPA-funded, five-year study. BPA should not fund more research here. IDFG should not simultaneously ask for money to study the negative effects of rainbow trout stocking and ask for money to continue rainbow trout stocking.
9.3D6	**Monitor effects of resident fish mitigation on endemic fish (westslope cutthroat trout) upstream from Dworshak.**	Oppose mitigation for mitigation. Stop current management practices if they are impacting native stocks.
9.3F2	**Evaluate potential for rebuilding sturgeon populations between Bonneville Dam and the mouth of the Snake River.**	The baseline study is already done. New studies should address a clearly documented hydropower-related loss and should not duplicate existing research. Overharvest is clearly the problem here.
9.3F3	**Evaluate potential for rebuilding sturgeon populations between Lower Granite and Hells Canyon.**	Studies should address a clearly documented federal hydropower-related loss and should not duplicate existing research.
9.3F4	**Baseline study of sturgeon in Lake Roosevelt. Assess potential for artificial propagation.**	Do one comprehensive study, not several smaller ones. Study should address a clearly documented federal hydropower-related loss and should not duplicate existing research. We already know sturgeon supplementation works.
9.3G1	**Bull trout studies and habitat improvement in Willamette and McKenzie rivers.**	Bull trout projects should be addressed in the context of ESA. Studies should address a clearly documented federal hydropower-related loss and should not duplicate existing research.
9.3G2	**Bull trout studies in the Deschutes, Grande Ronde, Hood, John Day and Umatilla subbasins.**	Bull trout projects should be addressed in the context of ESA. Studies should address a clearly documented federal hydropower-related loss and should not duplicate existing research.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.3G3	**Comprehensive genetic sampling of bull trout in the Flathead River Basin.**	Bull trout projects should be addressed in the context of ESA. Studies should address a clearly documented federal hydropower-related loss and should not duplicate existing research.
9.3H4	**Increase rainbow trout in the Kootenai River.**	Oppose. Rainbow trout prey on sturgeon eggs. This may adversely affect a listed species.
9.3H6	**Fund test plantings for shoreline revegetation.** Examples: Hills Creek, Dworshak, Libby.	Studies should address a clearly documented federal hydropower-related loss and should not duplicate existing research. Do not use exotic vegetation.
9.3H8	**Watershed restoration program above Izee Falls.**	Oppose. Project doesn't address a specific federal hydropower-related loss.
9.3H9	**Study natural production of kokanee above Chief Joseph Dam.** (In tributaries to Lake Roosevelt.)	Research should build on existing data and ongoing studies.
9.3H10	**Plant trout in areas not accessible to anadromous fish, buy shoreline for fishing sites.**	Oppose. Planting fish where they don't naturally occur runs the risk of altering natural ecosystems. The Act directs BPA to mitigate for fish losses, NOT to provide public fishing sites and education.
9.3H11	**Study potential for enhancing fish in Moses Lake.**	Oppose. Resident fish problems in Moses Lake are not caused by the federal hydropower system.
9.4A1b	**Design, construct and operate a bull/cutthroat trout hatchery on the Coeur d'Alene Reservation.**	Bull trout projects should be addressed in the context of ESA. During the Hungry Horse Amendment process, Council ruled that bull trout hatcheries were risky and unsuccessful.
9.4A1e	**Extend monitoring of CDA and Colville trout and kokanee hatcheries through the year 2000.**	Base monitoring on easily measurable objectives which address data gaps and track the progress toward biologically achievable goals.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.4A1(F)	**Allow resident fish substitution measures to affect power production and drawdown of Lake Roosevelt and Banks Lake.** (Deletes language which states mitigation measures shall not affect drawdown of Banks Lake and Lake Roosevelt as needed for power purposes).	Oppose. Don't use reservoir operations as a mitigation tool. There are other equally biologically effective ways to enhance resident fish.
9.4A1f-k	**Bass, bull/cutthroat trout hatchery, habitat improvement, bass nursery slough on Pend Oreille River-Kalispel Tribe.**	Bull trout projects should be addressed in the context of ESA. Bull trout hatcheries are risky. Water temperatures in the Pend Oreille river are too high for bull trout. This project must be coordinated with Pend Oreille PUD.
9.4A1n	**Baseline study of resident fish in Kootenai River in Idaho-Kootenai Tribe.**	Studies should not duplicate existing research.
9.4A1o	**Operate and maintain existing rainbow trout net pens in Lake Roosevelt.**	Good example of a local effort to solve a problem. BPA could share costs. Ecological risks should be minimized.
9.4A1p	**Study ways to prevent resident fish from being swept downstream out of Grand Coulee reservoir.**	Oppose. If providing flows for anadromous fish increases the entrainment rate then fisheries managers must take responsibility for their decisions.
9.4A2	**Fund resident fish substitution above Hells Canyon.** (0 percent, 8/11, or 35 percent)	Oppose. BPA can't fund any resident fish substitution projects above FERC-licensed dams.
9.4A25-6	**Resident Fish Substitution: Hatchery and habitat improvements on Duck Valley Reservation.**	Oppose. BPA can't fund any resident fish substitution projects above FERC-licensed dams. (Hells Canyon)
9.4A2h	**Evaluate operating procedures at American Falls Dam.**	Oppose. Not BPA's responsibility. BOR has not generated electricity.
9.4A3a	**Construct and operate trout ponds on the NPT Reservation.**	Oppose. Put-and-take fishery is pure economic mitigation, does not contribute to ecosystem restoration. Points again to the need for negotiated agreements.

Phase IV Resident Fish and Wildlife Measures

Measure	Issue	PNUCC's Position
9.4A4	Study crayfish in Lake Billy Chinook. Generate management recommendations to allow a biologically sound tribal commercial fishery.	Oppose. This is a commercial operation in a FERC-licensed reservoir.

NIU
Northwest Irrigation Utilities

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October 28, 1993

The Honorable Peter DeFazio
U.S. House Representative
1233 Longworth H.O.B.
Washington, DC 20515

Dear Representative DeFazio:

At your September 25, 1993 hearing in Eugene, Oregon, I testified on behalf of the Northwest Irrigation Utilities in support of cost-based rate treatment for irrigation pumping loads. During the comment exchange between yourself and members of Panel III, you addressed a statement to me that summer energy may have a higher value to the Federal base system in the form of exchanges with southwest utilities. We have discussed this issue with the Bonneville Power Administrative market specialists. Based on these conversations, we would like to share two major points relating to summer energy values.

Several factors effect the Bonneville-California Utilities Power Exchange. First, the available secondary energy for export to California depends significantly on water conditions. During an average water year, the available secondary energy to California exceeds their market demand and the PNW-SW inertia capacity during the months of May and June. In July, likely California market demand would be essentially equivalent to secondary energy. During a low water or near low water period, there would not be any secondary power available to California, except in May. Secondly, the price of the power being sent to California should be considered. During the months of July and August, power sales to California reflect the variable costs of the resources being displaced by the California utilities -- namely, the variable costs for gas and coal-fired plants. These power prices are in the 10 to 25 mills/kwh range, a price range that is similar to the summer energy costs for Bonneville's PF customers. The timing and quantity demanded for power purchases determine whether prices to California utilities equal or exceed in-region power prices.

Thus, it appears as if the question you raised does not have a "simple answer," but one based on assumptions and conditions. In that regard, Northwest Irrigation Utilities (N.I.U.) will continue to work with Bonneville and other interested parties in the development, review, and application of these planning parameters.

In a broader sense, there are many other factors that could determine the nature of Bonneville-California utilities power exchange. These would include the following: 1) Whether Bonneville has the legal or institutional authority to base in-region, wholesale power rates on inter-regional marginal cost prices, and 2) whether this rate-making approach could be based on sound utility economics for resource planning and acquisition, or 3) whether inter-sector equity is being acknowledged, given that the irrigation load has not required Bonneville to acquire new resources in over a decade and is anticipated to decline further in the future. N.I.U. has a fundamental interest in these issues. However, the focus of this letter is to respond to your inquiry, rather than providing position statements on expanded topics.

Representative DeFazio, thank you for the opportunity to testify on September 25th on behalf of N.I.U. and for considering these additional points. N.I.U. will be exploring issues raised in the hearing as well as share our observations and findings as we work with Bonneville in the months ahead.

As a special note, I am pleased to advise you that Northwest Irrigation Utilities has a new Executive Director, John Saven, as of mid-October. John has an extensive background in Northwest public power issues and will be representing the collective interest of N.I.U.

Sincerely,

Don Clayhold
N.I.U. Board Representative

DC:ml

cc: Members of The House Natural Resources Committee Bonneville Task Force
Senator Mark Hatfield
Congressman Tom Foley
Congressman Robert F. Smith
Congressman Jay Inslee
Congressman Norman Dicks
Bonneville Power Administration, Randal W. Hardy, Administrator
Northwest Irrigation Utilities Board of Directors

Columbia Basin Institute CBI

TESTIMONY OF
THE COLUMBIA BASIN INSTITUTE

BEFORE THE BONNEVILLE POWER ADMINISTRATION TASK FORCE
OF THE HOUSE COMMITTEE ON NATURAL RESOURCES

BPA'S IRRIGATED AGRICULTURE POLICY:
WATER CONSERVATION AND ENERGY PRICING

William Bean
Rick Gove

1 November 1993

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The Columbia Basin Institute conducts research, worker education and resource conservation projects at the direction of a Board of Directors composed of representatives of organized labor, natural resource conservation and farmworker organizations in the three-state Columbia Basin region.

In late 1992 the Institute distributed an analysis, which we append, opposing the continuation of the irrigation discount and BPA's imminent implementation of a water conservation plan proposed by Northwest Irrigator Utilities (NIU). In 1993, the Institute intervened in the BPA rate case, opposing the irrigation discount in its present form, and also filed a formal protest with the GAO concerning BPA's failure to follow proper contract solicitation procedures concerning the agency's intended funding of NIU's water conservation plan. NIU's plan was criticized by many regional water experts, economists and the Oregon members of the Power Planning Council for being a redundant and uneeded water conservation study proposal. In pre-litigation negotiations with BPA, the Institute agreed to a modified NIU contract upon agreement by BPA to form a water policy committee to develop an effective water conservation program. To date, BPA has neither developed a water conservation plan, nor initiated formation of the committee.

We submit the following testimony as a briefing on questions posed by the Bonneville Power Administration Task Force regarding the agency's policies in irrigated agriculture. In particular, we address the issues of BPA's water conservation and pumping power pricing on the Columbia Basin, responding, respectively, to questions 4 and 6 posed by the Task Force in its recent hearings in Boise and Eugene.

Due to the mounting social and environmental external costs of irrigated agriculture in the Columbia Basin, in the following comments we advocate investment by BPA in water conservation measures which accomplish the secondary objectives of water quality improvement and increased farmworker employment. But BPA's investments in water conservation should be driven by and can be justified in terms of a cost-benefit strategy based on the economic values assignable to the water's instream recapture: e.g., hydropower and the fishery. Because BPA's current policies in agriculture are self-contradictory and accomplish none of these objectives, we generally advocate the elimination of the irrigation discount and modification of the agency's conservation program activities in irrigated agriculture. We recognize that BPA's current efforts to rationalize its policies may jeopardize its ability to fulfill its historic commitment to subsidy of rural public utilities. Nevertheless, neither the irrigation discount nor the agency's misnamed conservation program -- Water Wise -- is economically rational. But their elimination should not conclude BPA's special efforts in the Basin's irrigated communities. The conservation of hydroelectric capacity in water can be good rural policy, economically and environmentally.

Introduction

Substantial federal investments in public power and irrigation projects in the Columbia Basin were initiated by a social policy intended to benefit rural communities and small farmers. Today, while some sectors of the agricultural economy have benefitted handsomely from federally subsidized power and water, the Basin's rural communities are economically and environmentally distressed as a consequence of the unmitigated external costs of irrigated agriculture. Unemployment and poverty levels are high, ground and surface water supplies depleted and contaminated. Now that the capacities of the hydroelectric system are exceeded by the energy demands arising from expansion in the region's urban areas, hydropower opportunity must be added to the external costs of irrigated agriculture. Irrigation imposes hydropower opportunity costs in two ways: first, under some circumstances, water now has a higher economic value in hydropower production than in agricultural production; second, irrigation's inefficiencies impose depletions and diversions upon the water management system which are technologically unnecessary.

Through its energy pricing and programmatic investment policies BPA has the capacity to mitigate and remedy these costs, abating water quality contamination, providing employment opportunity and recapturing water from irrigation for hydropower production and the fishery. But BPA's current policies exacerbate rather than remediate these externalities, and require reorientation.

It is nearly 60 years since the Roosevelt administration initiated the system of federal subsidy which forms the basis of the Basin's agricultural economy. From a position of abundant natural and public resources, the Basin has been reduced to a state of environmental degradation and socioeconomic distress in its small irrigation-dependent communities. Salmon species face extinction, and the region's economic advantages in the Columbia River system's hydroelectric resources are fiscally threatened.

The challenge facing federal policy makers on the Basin today is to devise a means of restoring natural resources, preserving what remains of the region's economic advantages provided by the public power resources administered by the Bonneville Power Administration, and protecting the interests of the small farmers and agricultural workers who were, after all, the intended beneficiaries of public investment in irrigated agriculture and public power in the Columbia River Basin by the New Deal.

In the following testimony we describe two irrigation subsidy programs -- the Irrigation Discount and Water Wise -- which now cost BPA roughly $15,000,000 annually. In their current configuration neither progam produces any discernible benefit to rural communities or the environment, the benefits being captured mainly by larger corporate farms owned by outside investors. Public

investments of similar magnitude could however be redirected in ways which would accomplish these objectives by concentrating on labor-intensive water conservation efforts among smaller farmers, improving water quality, employment opportunity and enhancing hydropower production in the bargain.

BPA, Conservation and Irrigated Agriculture

In the following comments we use the term "water conservation" in two senses: Water may be conserved in irrigation through its retirement from agricultural production, temporarily or permanently, by means of mechanisms such as water marketing. In this sense the Soil Conservation Service "conserves" water and soil through cropland retirement programs. A second sense in which water may be conserved is through improvements in the efficiency of its application. Only in the first sense is the water conserved certainly recaptured for in-stream uses. Water conserved through improvements in efficiency may or may not be recaptured in stream. Most of the following comments deal with the latter case.

As a hydropower marketing agency, BPA investments in efficiency-induced conservation should, as a threshold condition, be made only where instream flow recapture is guaranteed. We offer no comments on the question of how recaptured water should be distributed. Potential instream benefits for both hydropower and salmon can be realized through a water conservation program containing a mechanism for the recapture of water. How these benefits are allocated among fish and hydropower is beyond the scope of the Institute's testimony. We generally agree with our colleagues in the Northwest Resources Information Center and the Natural Resources Defense Council that water conservation does not by itself offer a solution to the resource management crisis precipitated by the listing of salmon species under the ESA. Water conservation is one among many instruments available for restoration of the Columbia Basin's natural and public resources.

Socioeconomic Externalities of Irrigated Agriculture

Decades of public subsidy have evolved an agricultural industry in the Columbia Basin highly dependent on cheap water, power and labor. Inexpensive water and power attract labor-intensive forms of commodity production and processing which import large numbers of impoverished and underemployed Mexican-American workers into rural communities lacking investment in infrastucture sufficient to adequately house, educate and service the ethnic workforce recruited. Workers are imported from Mexico, while hay is grown so cheaply that it can be exported to Japan.

Federal investments in irrigation and public power have not brought prosperity to the Basin's rural communities, which now manifest the socioeconomic characteristics typical of industrialized

agriculture's externalization of social overhead costs. Unemployment and poverty are at high levels; educational, housing and municipal services are impoverishedd. The Basin's rural communities are in many respects poorer places to live than before the advent of federal water.

Environmental Externalities of Irrigated Agriculture

Cheap federal water and power, states' unrestricted granting of water rights, and the lack of water consumption regulation have provided little incentive to efficient irrigation practices, adding surface and ground water quality degradation to the external costs imposed by irrigated agriculture on the Basin's small communities. Over one third of nearly 500 residential wells tested in two counties in the Mid-Columbia were recently found in violation of EPA drinking water standards for nitrates;[1] ground water supplies have been mined in several locations, affecting municipal water supplies; and a 1992 EPA survey revealed contamination from irrigation runoff in all tributaries in the Columbia River Basin. The primary cause of these externalities is inefficient application of irrigation water.

Hydropower Opportunity Costs of Irrigation

With the full utilization of the Basin's hydroelectric resources in response to growth in energy demand in urban areas, hydroelectric opportunity must now be added to the external costs generated by water and power subsidies to irrigation on the Basin. The hydropower generating value of the Basin's water is a function of the elevation of its location in the dam system, measured in terms of total dynamic head. In 1993 BPA pays 60.64 mills per kWh for new thermal resources to meet firm demand.[2] In a low water year, this makes one acre-foot of water diverted by the Bureau of Reclamation behind Minidoka Dam in the Upper Snake River worth $106 in incremental energy cost terms, and renders its consumption in the production of hay or pasture an example of inefficient economic allocation of the hydro system's water resources: i.e., the hydroelectric value of the water is greater than the value of the hay it produces.

On the Bureau of Reclamation's Columbia Basin Project irrigators

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[1] Long-Term Effects of Irrigation with Imported Water on Water Levels and Water Quality, U.S. Geological Survey, Water-Resources Investigations Report 93-4060, 1993. See also, Characterization of Ground Water in Umatilla County, Oregon Department of Environmental Quality, Grondin, 1993.

[2] 1993 Final Rate Proposal; Documentation for the Wholesale Power Rate Development Study. WP-93-FS-BPA-04A, p. 239, July, 1993.

still pay only .5 mills, or $480,104, for 960,208,400 kWh of project pumping power now worth over $25,000,000 at BPA's 1993 Priority Firm Preference rate of 26.79 mills. This latter energy subsidy is reflected in the extremely low price paid by irrigators for water on the Columbia Basin Project and provides a disincentive to water conservation on projects now served by Reclamation's withdrawal of 2.8 million acre feet at Grand Coulee.

Roughly 7 million acres are irrigated from the Columbia River and its tributaries. On an average, 5 acre-feet are withdrawn annually, of which 2 acre-feet are lost -- mainly to the atmosphere. I.e., 35 million acre-feet (MAF) are diverted, and close to 14 MAF are depleted: i.e., lost, or consumed by crop production. In late 1992 BPA roughly estimated the hydropower value of irrigation's depletions of 14 MAF at over $200,000,000 annually on the basis of $25/MW-hr for firm energy.

Potential Recapture of Irrigation Water for Hydropower Production

BPA has no reliable estimates of the amount of lost hydropower attributable to irrigation's depletions and diversions which can feasibly be recaptured either through the various conservation measures available in the conveyance and application of irrigation water, or through leased or purchased acquisitions. Based on recent studies, it is known that only 65% of diversions reach the fields while 35% is lost to either evapotranspiration, direct evaporation, or returns to the river. Once the water reaches the field, crops use 35% and 20% is lost to nonbeneficial consumption. The remaining 10% joins return flows totalling 45% of the total diversion.[3] Thus 20% of the total diversion of 35 MAF, or 7 MAF is lost to nonbeneficial consumption.

While the value of the 7 MAF wasted in nonbeneficial consumption may be a theoretical $100,000,000 at $25/MW-hr for firm energy, the actual hydropower value of the recaptured water would be greatly influenced by the elevation of the point of diversion at which the conserved water is recaptured. E.g., 1 MAF recaptured in the Upper Snake would be worth ten times as much as 1 MAF recaptured at the John Day in the Lower Columbia. Water recaptured from the Bureau of Reclamation project at Grand Coulee would be worth nearly 4 times as much as in the Lower Columbia. E.g., applying an incremental cost rate of 60.64 mills/KWH to a conservation-induced reduction of 20% in Reclamation's annual diversion of 2.8 MAF at Grand Coulee Dam, the value of hydropower production recaptured would exceed $20,000,000 annually. Comparable reductions in diversions from the Lower Columbia above John Day would yield only

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[3] 1990 LEVEL MODIFIED STREAMFLOW 1928-1989; Diversion and Return Flow Patterns, Summation of Depletion Adjustments, Evaporation Adjustments and 1990 Level Modified Streamflow. Pg. 9, January 1993.

$5,000,000 in hydropower recapture.

BPA has commissioned several studies which demonstrate a considerable potential for water savings in improvements in the application of irrigation water. Irrigation efficiencies on the Basin now range from 40% in primitive flood operations, most often found on Reclamation-served projects where 60% of depletions occur, to 90% in the most highly capitalized center-pivot operations typically found on privately-financed corporate farming operations. One BPA-commissioned study indicates that water conservation from a scheduling program, implemented by the Umatilla Electric Cooperative, decreased water use by 39% for alfalfa.[4]

In some cases improvements in efficiency of water application can lead to increased consumption of water by crops. However, even in such cases the hydropower value of water savings may exceed the increased amount of water utilized, or depleted by crop consumption. E.g., a flood irrigated farm may currently divert 7 feet per acre, of which 3 acre-feet is consumed by the crop and 4 acre-feet per acre returns as runoff: a 40% - 50% efficiency level. The result of a conversion to more efficient sprinkler irrigation may increase the amount of water consumed by the crop to 4 acre-feet per acre, but because of the efficiency increase to 70% with sprinkler irrigation, the actual diversion may reduce to 6 acre-feet or less, providing a potential hydropower recapture at the point of diversion of one foot per acre. Where substantial differences in total dynamic head exist between the point of diversion and the point of return flow, as in the Columbia Basin Project, significant hydropower benefits may thus be derived from the conversion despite the increased uptake by crops. The increased efficiencies may also decrease the non-beneficial consumption of water on the farm, and improve water quality.

Socioeconomic and Environmental Considerations Influencing a Hydropower Recapture Strategy on the Columbia Basin

A distinction must be made between economic and technical inefficiencies in irrigation's usage of water resources on the Basin. It appears that a signficant amount of water now diverted and depleted in irrigation in the upper reaches of the system is now or will soon be worth more to the regional economy in low water years if it is left in the river for hydropower production, regardless of the efficiency of water application. In such cases of uneconomic usage, inefficiencies in irrigation technique are irrelevant. The purchase of such water with public funds for public purposes will probably constitute the most cost-effective conservation measure available, on the basis of principles similar

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[4] Potential Conservation Opportunities from the Use of Improved Irrigation Scheduling in the Pacific Northwest Region. PNL-5416; UC-95c, March 1985.

to the Soil Conservation Service's Conservation Reserve Program. Capitalizing conservation measures such as conversions from rill or flood irrigation to sprinkler with public funds merely escalates public costs, particularly as the hydropower value of the water increases.

On the other hand, while purchase of water from its uneconomic agricultural uses may be the most cost-effective measure in terms of hydropower value, effects on local economies may rightly place limitations on its application in political practice. For example, BPA has recently undertaken a pilot project near Ontario, Oregon which is attempting to lease nearly 30,000 AF, currently held by the Skyline Farm, for instream hydropower and fish benefits. BPA's water leasing pilot provided some consideration of pending impacts to labor in the community, but did not contemplate mitigation of the socioeconomic impacts on the labor force and the community. As a partial consequence, the pilot has encountered political opposition in the local community. It thus appears that any general strategy for hydropower recapture through retirement of irrigated acreage will necessarily include a socioeconomic analysis which addresses the job losses which may be involved, as well as a mechanism to mitigate such losses. The irrigator in such cases will presumably receive some market-based price for the water: it is the workers who will be harmed, and whose unemployment will simply add to the public costs of the water transfers. Any general hydropower-oriented water transfer strategy clearly requires a displaced worker component.

By contrast, where crop value and hydropower cost-benefit ratios are favorable, and a mechanism for recapture of conserved water exists, the capitalization of management and labor-intensive irrigation efficiencies such as scheduling could offer both increased hydropower capacity for the region, as well as possible job-creation and training opportunities for the local workforce.

In addition to the obvious in-stream benefit considerations, such as increased hydropower capacity, watershed restoration and flows for salmon, which should place additional constraints on the location of public investments in water recapture, the restoration of the Basin's water quality offers another strategic objective for an effective water conservation program. E.g., ground water quality contamination in the Mid-Columbia Basin has been linked by Soil Conservation Districts to inefficient irrigation practices. Public investment of irrigation efficiencies may in such cases be motivated by water quality improvement objectives, in addition to hydropower recapture and other instream benefits.

BPA's Irrigation Policies

Bonneville's irrigation energy pricing and related conservation programs currently consist in an industry-wide pumping discount and a capital subsidy program, Water Wise. In their present

configuration the two are self-contradictory in terms of energy conservation, and bear no relationship to the potential hydropower values of water conservation.

The Water Wise Program

As we have pointed out, the goals of irrigation efficiency and recapture of water for instream benefits are sometimes in conflict in irrigated agriculture. Irrigation efficiencies motivated by the goals of increased yields may in practice increase crop consumption of water. Or the irrigator may simply apply the conserved water to additional acreage, a practice known as water "spreading." Similarly, energy efficiencies in the pumping and application of irrigation water may entail increased crop consumption of water, while reducing run-off and non-beneficial consumption. In no case can the recapture of water for instream benefits be assumed as a consequence of public investment in conservation of either irrigation energy or water.

Nevertheless, BPA currently spends roughly $2,000,000 annually in cost-sharing agreements designed to induce energy efficiencies in irrigation under the auspices of a program entitled Water Wise. However, the Water Wise program, despite its title, is an energy conservation program. It is the agency's vehicle for the acquisition of its stated goal of 45 AMW in conservation in irrigated agriculture. Not suprisingly, Water Wise fails to function as an effective water conservation program. Moreover, its efficacy, if not its cost-effectiveness as an energy conservation program is doubtful.

The class of irrigators most responsive to the generally increasing energy costs of the past decade has been the energy-intensive highlift pumping operations found on the large privately financed farming operations in the Mid- and Lower Columbia Basin. Paying nothing for water, these irrigators have implemented highly sophisticated irrigation efficiencies in order to hold down relatively high energy costs and increase yields through greater efficiencies in the application of water. Such highly capitalized and professionally mangaged operations would in all probability have made such efficiency investments without the federal subsidy. By the same token, they have had both the incentive and the ability to capture a large share of BPA's energy-conservation subsidies offered under the Water Wise program.

Despite these well-known facts, BPA has historically regarded water conservation as a desirable by-product of investments in energy efficiency under the Water Wise program. Not suprisingly, the agency has established no objectives for water conservation as products of the energy conservation subsidies. Lacking any mechanism for recapture of saved water, if any, and investing the subsidies at points lower down in the dam system where the hydropower potential of recaptured water would in any case be of

relatively low value, the Water Wise program makes no discernible contribution to water conservation or hydropower recapture in the Columbia Basin.

In short, Water Wise primarily benefits irrigators who would make the same efficiency investments without the subsidy; the program lacks any mechanism to actually recapture water; and it places its investments at points in the Columbia River Power System where the hydropower potential of any recaptured water is relatively low.

The Irrigation Discount

Since 1985, BPA has extended a discount of 20% off wholesale rates to irrigators in the customer area. In the current biennium the discount, at 4.71 m/KWH, will cost the agency nearly $30,000,000 in revenues and, based on studies commissioned by BPA in the late 1980s, induce an additional 3% in irrigation load[5], thus adding to BPA's costs and contradicting the ostensible energy conservation purposes of its Water Wise program.

In the records of decision since the discount's inception, the agency has employed various justifications for its extension. Initially justified as a distressed industry provision during the agricultural slump of the mid-1980s, then adopted as a means of increasing load and revenues during a temporary power surplus, the agency currently supports continuation of the discount on the grounds that the economic impact of its elimination would be harmful to irrigated agriculture. But reports by BPA's own economic analysts demonstrate the relative health of agriculture in the Pacific Northwest generally: returns to agricultural capital are generally 50% higher in the region than elsewhere in the U.S. The only notable area of agricultural distress is among those irrigators who now face the consequences of over-pumped ground water supplies, a situation to which the irrigation discount, ironically, has probably made its most calculable contribution by lowering the cost threshold of ground water pumping.

Distribution of the Discount's Benefits

Investor-owned utilities receive roughly 40% of the discount, passing it through to their irrigation customers. Public utilities in the Snake River and Mid- and Lower Columbia Basin distribute the remaining 60%, chiefly to the same energy-intensive, high lift pumpers who also receive energy conservation subidies under the Water Wise program. A recent Institute analysis of one public utility in the Lower Columbia -- historically the leading public

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[5] The Role of Electricity in Pacific Northwest Irrigated Agriculture, Volume 2: Background Materials and Support Documents Sections D-G, DE-RP79-88BP39166, pg.E-6, February, 1989.

user of the discount -- revealed that in 1991 out of 400 irrigators in the area, four large farming operations received 20% of the value of the discount. Ten large irrigators captured nearly 50% of the discount in the same area.[6] Due to the energy-intensive nature of the highly-capitalized irrigation systems commonly found on the larger farming corporations unserved by Bureau of Reclamation projects, BPA's discount chiefly benefits the investors in the larger farming operations rather than the smaller farmers on the Bureau's irrigation districts, where pumping lifts are low.

Summary Assessment of BPA Policies

Despite the fiscal significance of the potential for hydropower recapture, BPA currently makes no plausible effort at water conservation and recapture. The agency's irrigation energy conservation program, Water Wise, is contradicted by its irrigation discount.

Due to the concentration of the benefits of both the Water Wise program and the discount in the same class of high-lift pumpers, the agency concurrently pays the same irrigators to conserve energy to whom it also discounts the price in a manner which has the theoretical effect of increasing energy demand. What is most likely is that -- due to the inelastic nature of water and energy demand in the production of the high-value crops grown by the highly-capitalized farming operations in the Mid-Columbia -- both the discount and Water Wise have little or no effect on the investment and irrigation management decisions of energy-intensive, highly capitalized farming operations. Public investments in energy conservation and discounted pumping rates gratuitously subsidize this class of pumpers. If the irrigation discount has indeed induced increased energy demand by irrigators -- as earlier BPA studies of demand elasticities concluded -- it is most likely among the class of marginal pasture and alfalfa irrigators for whom energy and water costs constitute the bulk of variable costs. In short, the discount probably induces increased energy and water use among the least economic users of water and power on the Basin, while gratuitously subsidizing the most efficient.

BPA's policy deficiencies vis-a-vis irrigated agriculture are in part attributable to the relatively new circumstances created by full utilization of its resource base. No longer being in a surplus situation, BPA must now acquire expensive new resources, while repaying past failed resource acquisition debts. Since its inception, Bonneville has generally operated in a situation of energy surplus. This era of abundance fostered many programs which

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[6] The four beneficiaries in the Umatilla Electric Cooperative service area are: Western Empires Corporation; Mikami Brothers; Big River Farms; and Potlach Farms (formerly East Oregon Farms).

did not warrant stringent adherence to conservation or efficiency standards.

Also, BPA has historically been most responsive to well-organized and influential interests among its customer groups in the region, often at the cost of rationality in its programs and rate designs, as evidenced by the disarray in its current policies and practices in irrigated agriculture. BPA's responsiveness to special interest pressures partially accounts for the fact that large irrigators, whose economic self-interest is sufficient to induce investments in energy and water application efficiences, are subsidized with conservation cost sharing agreements and discounted power rates, while smaller farmers who may require specific forms of assistance receive but a relatively small share of BPA's expenditures.

BPA's failure to design and implement an effective water conservation program is also a consequence of the agency's historical relations with utilities. By virtue of its role as a power marketing agency, BPA's natural relations with agriculture are with the public utilities with large irrigation loads; irrigator utilities, in turn, are often dominated by the organized interests of large users of pumping power such as Northwest Irrigator Utilities. Thus while BPA is aware that the most inefficient irrigation practices are found on Reclamation-served irrigation districts -- where water is cheap, pumping lifts low, farmers small, capital and management scarce -- the agency continues to subsidize the larger, more organized corporate farming operations.

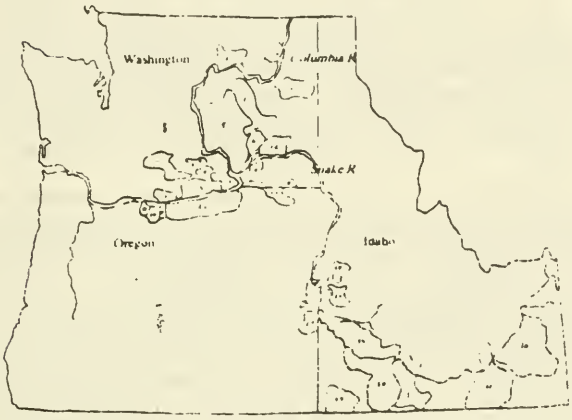
It seems clear that an effective program of investment by BPA in water conservation for purposes of instream recapture is desirable. But it would require strategic concentration among the least efficient class of irrigators where instream recapture at the point of diversion makes such investments cost-effective. To accomplish such a strategy BPA would be required to develop a program in concert with the Bureau of Reclamation, and through Reclamation with the irrigation districts. USDA's Conservation Districts and the Soil Conservation Service would also require involvement. Notably, both USDA and the Bureau of Reclamation have specific mandates to accomplish water conservation and water quality improvement in agriculture, while BPA's conservation responsibilities are expressed in terms of energy savings, not water.

Columbia Basin Institute

CBI

ISSUES IN BPA'S 1993 & 1995 RATE CASES:

THE IRRIGATION DISCOUNT, CONSERVATION & HYDROPOWER OPPORTUNITY COSTS



William H. Bean
30 October 1992

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Introduction

Irrigated agriculture is unique among BPA's industrial customers. Although representing only 7% of the agency's total power sales, the industry's use of electricity to withdraw water from the Columbia River system complicates pumping power ratesetting issues. Not only does irrigation use power in pumping, but the consumption of water by agriculture -- 90% of all consumptive use of water in the Basin -- entails hydropower opportunity costs in so far as water withdrawn from the system is unavailable for hydropower generation. Withdrawal of one acre-foot of water from behind Grand Coulee, for example, entails that 1016 kWh of generation are lost from 11 downstream dams. 1)

When one considers that an estimated 35 million acre-feet of water are currently withdrawn from Columbia River sources to irrigate over 4.9 million acres in the Basin, and that the State of Washington estimates that 50% of all irrigation water now withdrawn in that state is in excess of crop requirements, issues pertaining to irrigator efficiencies and the potential role of BPA's pumping power rates in accomplishing those efficiencies assume special significance for all ratepayers in the Pacific Northwest. 2) Conservation by irrigated agriculture not only offers public benefits in the form of reduced energy demand, but because irrigation water may be recovered for hydropower generation, conservation-induced savings in the agricultural industry hold out the promise of significant public benefits in the form of increased hydropower capacity. Conversely, inefficient usage of power and water by irrigators exacts disproportiately high costs on the hydropower system in the form of lost hydropower opportunity.

Since 1985 BPA has provided irrigators with a pumping rate discount, currently projected at 4.7 mills for fiscal years 1994-1995 and producing a revenue deficiency of roughly $30 million for the biennium. Compared to total agency revenues around $1.5 billion and distributed over all ratepayers in the Pacific Northwest, the revenue deficiencies generated by the pumping discount appear insignificant. But the significance of the discount is magnified when considered in terms of its effects on irrigation's continued inefficiencies, and the implications of those inefficiences, in turn, for lost hydropower generating capacity and continued degradation of water resources on the Basin. The discount has had the effect of partially insulating irrigation from regional rate increases, thus suppressing irrigators' demonstrable tendencies to decrease water consumption in the face of rising energy costs and depriving the system of recapturable water for hydropower generation. These and other hidden costs of the discount require articulation in BPA's review of energy pricing to this industry, both from a public policy standpoint and also because they clearly illustrate the stake all other ratepayers have in the issue of energy and water conservation by irrigated

agriculture in the Columbia Basin

The importance of energy policy planning in relation to irrigated agriculture in the Pacific Northwest was recognized by congress in 1980 in the Pacific Northwest Power Plan, wherein BPA was expected to develop conservation programs which would induce more efficient delivery and application systems, water scheduling and deficit irrigation in agriculture, thereby reducing power consumption in the industry by 30% by the end of the decade. 3) BPA has not achieved that goal. The Plan also discussed the value of hydropower generation losses generally due to irrigation water diversions, but gave no explicit consideration to the linkage between firm and nonfirm hydropower production and irrigation water conservation in the Columbia River system. It is notable that ten years later, BPA still has not established such linkages; neither in its cost calculations of the depressing effects of its irrigator discount on recovery of generating capacity through decreased water consumption from the system's hydropower base, nor in the establishment of its conservation goals in the Water Wise program, where after ten years the agency still has not established linkages between the power and water conservation payoffs available through various conservation methods.

With the advent of the 1993 and 1995 Rate Cases, in which BPA proposes to continue the irrigator discount at increased costs to the agency's revenue base and, in the 1995 Rate Case, consider questions of rate design and their relation to conservation, it may be useful to review the history of the discount and some of the issues which have received less than full discussion in previous Records of Decision on the discount.

A related issue is generated by a current proposal by Northwest Irrigator Utilities (NIU), the historical advocate of subsidized pumping rates, to assume administrative control of BPA's irrigator conservation program. NIU's success in this endeavor would, in our view and for the reasons we outline below, exacerbate the difficulties currently faced by BPA in implementing its irrigation conservation program -- difficulties further exacerbated by the pumping discount -- and compound BPA's failure to establish the crucial linkages between power and water savings and the hydropower capacity recapture potential currently imprisoned by irrigated agriculture in the Columbia Basin. While it is probably within the scope of the agency's authority to delegate programmatic responsibilities to independent entities, we believe it is questionable whether the agency can fulfill its statuatory conservation duties under the 1980 Regional Act on the basis of such a demonstrably flawed and inadequate plan as the one recently proposed to the agency by NIU. And the importance of this question goes beyond matters of agency protocol and the minutae of industry-specific conservation programs. Proportiate to its unanalysed contribution to the regional economy, irrigated agriculture currently asks that we bear a significant burden of external costs

in the form of rate subsidies, wasted hydropower capacity and resource degradation. Before BPA rewards the industry with a contract to perpetuate these costs upon us, these issues require review.

1.0 BPA's Irrigator Discount is Unexamined Social Policy

1.1 The discount is not supported by an economic justification.

NIU was formed in 1978 expressly to lobby BPA for the discount, something they did not succeed in accomplishing until the 1985 rate case. Both in the 1985 record of decision and in subsquent decisions to maintain the discount in 1987 and 1989, BPA's decision to extend the discount was justified in terms of the industry's distress. It is therefore a matter of record that the discount is intended by the agency to serve an economic purpose. It is interesting to note that the conditions -- a high dollar and high interest rates -- originally offered as the temporary causes of the industry's need for discounted rates no longer obtain. The 1987 Record of Decision merely cites "the uncertain long-run economic health of irrigated agriculture," hardly an economic situation unique to that industry. During BPA's period of surplus in the mid-1980s, an additional justification was offered for the discount as a means of increasing BPA revenues, based on the assumption of demand elasticities which have been shown to be nonexistent. 4) In assuming demand elasticities in irrigated agriculture sufficient to justify the discount, BPA ignored the findings of a 1984 study produced under agency contract by Northwest Economic Associates. 5)

1.2 BPA confuses irrigator profits with the economic health of agricultural communities.

Records of Decision indicate that BPA intends some benign socioeconomic purpose in continuing the discount as a "distressed industry" provision in the rate design. And of course the difficulty with it from a public policy perspective is that its purposes are so unarticulated, and the discount so general -- all irrigated agriculture is included -- that there is no means of verifying whether it is a cost-effective means of accomplishing that purpose or not. Studies done for BPA on the impact of the discount focus on maintenance of net returns to irrigators, wherein there is no evidence of distress. 6) Moreover, all studies done for BPA on the issue of irrigator responses to pumping rate increases show little or no retirement of land or changes in cropping patterns in the face of very considerable hypothetical rate increases. 7) There has been no significant retirement of land or change in cropping patterns as a result of the considerable pumping rate increases of the past seven years. There is no evidence of distress in irrigated agriculture in terms of returns

to irrigators per se.

Ironically, all of the counties in which irrigation is dominant really are "distressed areas" -- so classified by their respective states on the basis of the underemployment and low wages paid by the industry to the settled Mexican-origin workforce. BPA's Records of Decision are silent on this distress.

1.3 BPA fails to consider more cost-effective means of enhancing the "long-term economic health" of the industry.

Although the improvements in irrigators' net returns attributable to the discount are 3%, if the agency's purpose is to sustain returns to irrigation capital other forms of subsidy to irrigators should be considered in lieu of the pumping discount. Given the current value of water left in the river, the marginal cost of power and the negative externalities associated with excessive irrigation, there is sufficient reason to believe that irrigators' returns may be maintained at less public cost through a program of direct payments to irrigators for reductions in water and power usage in the context of full market pricing for pumping electricity. Certainly this option should be reviewed in BPA's next Record of Decision on the irrigation discount. And in so doing the agency should consider whether it intends to permit the export of subsidy to national ownerships, from which the region derives no economic benefit. Agricultural Production Area 22, for example, is an area in Northeastern Oregon dominated by national and multinational corporate farming operations and currently the largest beneficiary of the discount. APA 22'S portion will exceed $1 million annually in the next two fiscal years. BPA needs to determine what regional economic benefit accrues from the discount in such cases.

If, on the other hand, BPA intends to mitigate areas of real distress in irrigated agriculture -- the communities and the workforce -- the agency should consider more direct and cost-effective alternatives to a discounted pumping rate. One notable option in this respect has been suggested to the agency in a study by Northwest Economic Associates in the form of a direct labor subsidy for irrigation scheduling, which would have the effect not only of providing employment in irrigation management and thus addressing agricultural underemployment, but also recapturing hydropower opportunity and enhancing streamflow through instream water savings. 8) Similar proposals were made to the New York State Power Authority on the issues of hydropower subsidy and job retention. 9) The Tennessee Valley Authority also has well established subsidy programs aimed at areas of agricultural distress.

Surely the federal regulator of the world's largest hydrolectric system can do a better job of social engineering, if that purports to be the agency's purpose in maintaining the

irrigation discount, than the mere provision of a pumping subsidy at costs now approaching a biannual $30 million which saves no jobs, some portion of which is exported from the region, and the usage of which defers investment in conservation by irrigated agriculture in the Basin.

1.4 The discount accelerates retirement rather than preserving irrigation in areas of groundwater depletion.

Approximately 25,000 acres have been retired from irrigation on the Basin in the last decade due to groundwater depletion. Retirement of additional acres for this reason appears inevitable in other areas within the next decade, most notably in the Odessa and Stage Gulch critical groundwater areas, where pumping lifts are in excess of 400 feet for low-return crops. Pumping rate discounts of 10% - 20% will not preserve irrigation in these areas, but merely offer incentives to continue depletion of the resource. If these areas of agriculture are in structural decline, in part through exhaustion of a natural resource, it makes little sense to provide a discount with which to continue, for some undetermined short term, depletion of the resource without some review and planning to determine the effects upon the workforce and the communities affected by the exhaustion of groundwater supplies.

2.0 The Irrigation Discount Has Potentially Significant Adverse Environmental and Socioeconomic Consequences and Requires EIS Review in the 1993 Rate Case.

2.1 Increased water and power use and deferral of conservation measures is a well-documented irrigator response to discounted pumping rates.

BPA has known since 1981 that reductions in pumping rates motivate increased water and power use by irrigators. This was BPA's conclusion in its Environmental Report on the issue of the extension of pumping discounts through the residential exchange program to investor owned utilties at that time. 10) Every study commissioned by BPA since then has reached the same conclusion. 11) Although not elastic in the economic sense, the effects of discounted pumping rates -- even in a context of general rate increases -- "may delay capital investments which would improve irrigation efficiency," and motivate increased resource consumption, as BPA found in 1981. The same findings have been reiterated in 1986 and 1989 studies done for BPA by Northwest Economic Associates. 12)

2.2 To the extent that discounted pumping rates encourage water usage in excess of crop requirements and motivate deferral of conservation measures, they contribute to surface and ground water contamination caused by irrigation runoff.

This was essentially BPA's conclusion in 1981:

"Any increase in water use and energy consumption due to reduced rates for irrigation carries with it potential environmental consequences. Increased surface water withdrawals reduce the ability of streams to assimilate pollutants and decrease the water available for fish and wildlife. Irrigation runoff increases the load of silt and agricultural chemicals." 13)

The Franklin Conservation District has recently identified "cheap electricity compared to management time" as a contributing factor in excessive irrigation on 221,000 acres in that county, and, together with the USGS, identified irrigation runoff as a source of nitrate contamination in local residential wells, 46% of which now show contamination levels in excess of the 10 ppm standard. 14)

Contaminating effects of irrigation runoff in all tributaries of the Columbia River system have been identified in a recent survey by the Environmental Protection Agency. 15)

Several federal agencies are involved in anadromous fishery habitat restoration efforts in the Yakima River Basin, where tribal fishing and water rights are also at issue. A modeling study of the relationship between crop budget inputs and reductions in surface water contamination was done on the Yakima in 1976 by Whittlesey et alia, in which it was demonstrated that relatively small changes in cost inputs could decrease irrigation-related contamination by as much as 50%. 16)

The Yakima Basin currently has 36,000 acres of alfalfa and over 75,000 acres of other low-return forage crops under sprinkler irrigation, where pumping energy costs currently exceed 20% of crop budgets. A 1990 modeling study done at Washington State University has shown alfalfa to be a water-intensive crop most responsive to energy price increases in relation to reductions in water application, with decreases from 28 to 15~ acre-inches motivated by pumping price increases in the 33% to 66~ range. 17) BPA's irrigation discount is demonstrably related to continuing levels of surface water contamination and depletion in the Yakima Basin, bringing the agency's policies in conflict with the purposes of the federal and state agencies attempting habitat restoration in that area.

2.3 The irrigation discount lowers the threshold of groundwater depletion.

Washington limits withdrawals from groundwater by means of a criterion of "reasonable and feasible" pumping lift, in practice and in principle a pumping rate-related standard. 18) In Doherty v. Oregon Water Resources Director, 308 Or 543,783 P2d 519 (1989), plaintiffs argued, unsuccessfully, that pumping rates should determine the practical definition of sustainable yield as applied

to groundwater. OWRD's and irrigators' performance in the Stage Gulch and Butter Creek critical groundwater areas of Northeastern Oregon indicates that rates have influenced withdrawal practices. Groundwater depletions in the Snake River Basin of Idaho also suggest that rate-related factors have contributed to the rate of groundwater depletion.

In a 1984 study of irrigation from the Ogallala aquifer in Eastern Colorado, researchers found that,

> "...setting electricity rates is tantamount to setting water rates," and that "there is a direct link among energy price and energy and water use." 19)

The conclusion was that,

> "One way to prolong irrigation in eastern Colorado is to implement electricity rates that reflect both the higher incremental costs of energy and increasing scarcity of water in the declining Ogallala aquifer." 20)

2.4 Groundwater depletion adversely affects surface water, municipal and economic interests in the Basin.

Surface effects of groundwater depletion have recently been identified as issues of concern in an EPA survey of water quality on the Basin. 21)

Groundwater depletion also adversely affects various other interests in the system: aquaculture in the Snake River Basin, grazing in Eastern Washington, fish hatcheries, and, as described in a forthcoming study of the food processing industry by the Institute, industrial and municipal uses in every irrigator community in the Mid-Columbia. E.g., the city of Walla Walla recently petitioned Washington's Department of Ecology for a moratorium on new withdrawals by agriculture in that sub-basin: BPA's pumping discount contributes to that city's groundwater problem.

2.5 Depleted aquifers generate additional demands for water from the hydropower base.

In Umatilla County, Oregon, Echo and Stanfield are currently petitioning Oregon Water Resources for additional withdrawals from the mainstem to remedy failed municipal groundwater supplies and recharge irrigators' groundwater. The cost to BPA ratepayers, in hydropower opportunity costs, of that single withdrawal will be $4 million annually -- a high price for ratepayers to pay for irrigators' depletion of groundwater resources, and a price enabled by BPA-subsidized pumping rates which have been instrumental in the depletion of the resource, and which will continue to subsidize new

pumping from the mainstem. 22)

3.0 The Discount Generates Hidden Hydropower Opportunity Costs Which Require Estimation and Inclusion in BPA's Calculation of the Costs of the Discount in FY 1994 and FY 1995

3.1 The discount contributes to irrigation inefficiencies in Franklln County which cost BPA ratepayers nearly ~3 million annually in lost hydropower revenues.

The Conservation District has determined that 4" acre inches in excess of crop requirements are being applied to 221,000 acres in that county. From the point of diversion at Grand Coulee, these excesses entail a hydropower opportunity cost of $2,916,941 annually. 23) The irrigation discount had the effect of reducing pumping rates by 21% in Franklin County's Agricultural Production Area in 1987. 24) The district has identified low-priced pumping power as a factor contributing to excessive water applications by irrigators and their reluctance to engage in water conservation in that area.

An application of the modified Bernardo-Whittlesey model employed in NEA's 1989 study of irrigator responses to energy price increases would permit estimation of the amount of these hydropower opportunity costs directly attributable to the irrigation discount, thus enabling BPA to incorporate those hidden costs in the agency's fiscal planning for FY1994 and FY1995, in which the amount of the discount is expected to increase by 50%.

3.2 When combined with deferred conservation investments, the hydropower opportunity costs of the irrigation discount projected for FY 1994 & FY 1995 may equal or exceed BPA's projected discount-related revenue deficiencies.

Estimates similar to those for Franklin County can be made for that portion of the 4.9 million acres affected by the discount and under sprinkler irrigation from the Columbia River system where, based on Washington State's estimates, twice as much water is withdrawn than required by current cropping patterns. Generalizing Franklin County's estimates over various diversion points in the system yields annual hydropower losses approaching $40,000,000 attributable to excessive application alone, independently of losses in transmission. But such a generalization has no empirical basis, and lacks specific connection to the discount's effects on the potential for hydropower recapture in each production area. Nevertheless, there is clear enough evidence that the losses may be significant and require assessment by the agency.

It is striking, given BPA's early understanding of the depressing effects of pumping rate discounts on irrigator efficiencies and conservation investments, and the availability of

reports documenting the magnitude of irrigated agriculture's inefficiencies in the Columbia River system, that in none of the several studies commissioned by the agency on the subject of irrigation on the Basin has there been any attempt to estimate the potentially great hydropower revenues recapturable through price- and program-induced water conservation measures in this segment of industrial energy demand.

The same failure to make this linkage in conservation planning obscures the ratepayer savings possible in BPA's implementation of its irrigator conservation program, Water Wise.

4.0 BPA's Failure to Set Specific and Proportionate Energy and Water Conservation Goals is Inconsistent With the Agency's Duties Under the Regional Act and Entails Substantial Costs for All Other Ratepayers

4.1 BPA's goal of 17 average megawatts in conservation savings in irrigated agriculture substantially underestimates the water and power conservation savings available in the industry.

A Northwest Economic Associates study reported in 1986 that energy conservation savings of 120 avg. MW were available in irrigated agriculture, based on detailed studies by Battelle, commissioned by the Agency. 26) BPA's goal of 17 avg. MW in conservation in this industry by the year 2000 is less than half of the industry's share of BPA's conservation goal of 600 MW, based on total customer load, and less than 20% of the savings identified as technically available in irrigated agriculture.

4.2 BPA's failure to establish specific energy-water savings coefficients for the various irrigation conservation methods precludes the establishment of achievable water conservation goals.

Significant differences in water savings exist relative to the major conservation methods employable in irrigated agriculture. Pumping and transmission system efficiencies produce little or no water savings, for example. At the other extreme, irrigation scheduling and deficit irrigation yield substantial savings in water usage, while low pressure applications yield mid-range efficiencies in application of irrigation water. BPA's Water Wise program currently contains no mechanism for establishing priorities among these methods based upon separable water savings targets.

4.3 BPA has declined to evaluate the hydropower recapture potential of water-conserving methods and thus has no realistic basis for assessing the relative cost-benefits of the various energy-conserving methods in irrigated agriculture.

A 1985 Battelle study of the conservation opportunities of improved irrigation scheduling pointed out to BPA that,

"One of the major benefits that is excluded from this analysis is the potential for improved irrigation scheduling to result in increased water supplies within the Pacific Northwest's hydroelectric system. These additional supplies could be used to generate more hydroelectric power and/or enhance fish runs within the region's rivers and streams. It is generally believed that the indirect loss of energy from withdrawing water from the region's hydroelectric system for irrigation is significantly larger than the direct use of energy for irrigation pumping. Thus, inclusion of the indirect energy savings from reduced water usage through improved scheduling could have a significant impact upon future studies of the energy-conservation potential of improved scheduling." 27)

Seven years later BPA still has not evaluated the potential for improved irrigation scheduling in terms of the potential for increased water supplies in the Columbia River system. The reason for this ommission is clear enough: unlike capital subsidies in the retrofitting of irrigation hardware, irrigation scheduling and deficit irrigation require modifications in irrigator behavior, and the modification of behavior requires, among other things, a strong incentive. The obvious incentives are either the scarcity or high cost of irrigation water, or the high cost of irrigation power.

5.0 NIU's Proposal for Administratlve Control of the Water Wise Program Will Perpetuate BPA's Failures to Set and Accomplish Reasonable Power and Water Conservation Goals

5.1 Task III in NIU's 28 August "Implementation Plan~ is redundant and will yield skewed "Baseline" results.

Baseline studies have been accomplished in 1989 studies by Northwest Economic Associates, Vol 2, "The Role of Electricity in Pacific Northwest Irrigated Agriculture," and elsewhere. Baseline studies conducted on the basis of irrigators' power and water usage will in any case be inflated by the effects of BPA's irrigation discount since 1985 and would, to that extent, beg the question of appropriate allocations of water and power to irrigated agriculture.

5.2 Research and analytic components of the NIU proposal contain no provision for establishment of quantifiable water and conservation goals by Agricultural Production Area and omit to establish water and energy savinqs coefficients with which to establish separable water conservation goals.

5.3 NIU's proposal contains no assessment of the hydropower savings avaialable through instream water recapture consequent upon the various conservation methods.

5.4 NIU's primary constituency is large irrigators who are

already relatively energy-efficient and additional efficiencies by that class of irrigators are least likely to result in decrease in consumption of water resources.

In response to rising energy costs over the past decade, large center-pivot irrigators have already implemented substantial energy conservation improvements: this was reported to BPA by Northwest Economic Associates in 1986. 28)) Many of the large center-pivot operations in the Mid-Columbia, through conversion to low-pressure systems, already approach 80% efficiency in water usage. These improvements were made prior to availability of BPA's conservation rebate program, Water Wise, which until 31 December 1990 was restricted to small (480 or less) acreages. Water conserved by these operators will almost invariably be applied to additional irrigation.

5.5 Smaller irrigators, particularly those on irrigation district canal and surface water withdrawal systems, are reluctant to make conservation improvements and NIU's proposal contains no credible marketing plan to this class of irrigators,

A major obstacle to conservation by smaller irrigators lies in their widespread belief that a voluntary reduction in water consumption will result in a lowered allocation when anticipated cuts in water supplies are made by the Bureau of Reclamation and irrigation districts. Resistance to conservation on the part of these irrigators is rooted in their perceptions of economic selfinterest, regardless of the basis for these beliefs.

Resistance to low-pressure applications and improved scheduling on the part of this class of irrigators was confirmed in a recent study done by the University of Idaho. 29) One possible effect of the discount on small irrigators -- reported to BPA in 1986 by Northwest Economic Associates -- is that "farmers irrigating at night to save on electricity would shift back to the preferred daytime irrigation if rates were reduced." 30) The paradox here is that improvement in management -- combined with improvements in system -- was identified in the same report as potentially yielding energy savings as high as 25%, while equipment retrofits by themselves were estimated as likely to produce savings only in the 7% to 15% range. 31)

BPA's Snake River Area Office on 20 July 1992 reported only $318,000 in expenditures on Water Wise rebates to irrigators, against a budgeted $2.3 million for FY 1992 -- further confirmation of the low level of voluntary participation by irrigators in additional conservation improvements at this time on the Basin.

5.6 BPA's Snake River Area Office reports an achievement of 5 avg. MW in irrigator conservation since the program's inception in 1982, with an additional 7 - 8 avg. MW targeted by the year 2003. NIU's proposal is unlikely to accomplish that objective in a cost-

effective manner, if at all.

Given NIU's main constituency among larger irrigators in the Mid-Columbia, it is likely that energy conservation savings will be accomplished at relatively large expense in the form of costly, incremental improvements in large-irrigator efficiencies, from 80% to 90%, e.g., with little or no savings in water consumption and recapture of water for instream benefits and hydropower generation.

FOOTNOTES

1) Whittlesey, N., et al., 1978, "Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture," Washington State University for BPA, June.

2) p. 1, James, Larry, et al., 1991, "Irrigation Water Use Efficiency Demonstration Project Phase II: Conservation Assessment," State of Washington Water Research Center, Washington State University, July.

3) Houston, Jack Jr., Whittlesey, Norman K., "Modeling Agricultural Water Markets for Hydropower Production in the Pacific Northwest," pp. 221-231, Western Journal of Agricultural Economics, 1986.

4) "Preliminary Draft Task 3: The Role of Irrigated Agriculture in the Pacific Northwest," Northwest Economic Associates, November, 1988. See also, Majoro, Moeketski, "Response of Pacific Northwest Irrigated Agriculture to Rising Electricity Prices," Unpublished PhD dissertation, Washington State University Department of Agricultural Economics, Pullman, Wa., December, 1990 .

5) McKusick, Robert, et al., 1984, "Modeling and Analysis of Pacific Northwest Irrigation Rate Designs," Northwest Economic Associates for BPA, November.

6) Cf. p. 52, et passim, "The Role of Electricity in Pacific Northwest Irrigated Agriculture," Vol. 1, 1989, Northwest Economic Associates for BPA.

7) E.g., "Linear Programming Model Description and Results," Whittlesey, Norman K., et al., in "The Role of Electricity in Pacific Northwest Irrigated Agriculture," Section D, vol. 2, op.

8) pp. 71-73, "The Role of Electricity in Pacific Northwest Irrigated Agriculture,"

9) p. 237, Hertel, Thomas W. and Mount, Timothy D., "The Pricing of Natural Resources in a Regional Economy," Land Economics, vol. 61, no. 3, August, 1985.

10) pp. 5-7, 5-8, "Environmental Report," Bonneville Power Administration, September, 1981.

11) E.g., pp. xiv, 73, "The Role of Electricity in Pacific Northwest Irrigated Agriculture, vol. 1, op. cit.

12) pp. 4-1 through 4-15, "Marketing Electricity to Industrial Customers: A Study of Pacific Northwest Industries," 1986, Northwest Economic Associates for BPA, February.

Footnotes, Page Two

13) p. 5-8, "Environmental Report," op. cit.

14) 23 March 1992 correspondence and attachments, John Holmes, Project Manager, to William E. Hanson, U.S. - GAO, Seattle.

15) "Columbia River Summary Report," 1992, EPA Region 10 for the Northwest Power Planning Council, June.

16) Pfeiffer, George, and Whittlesey, Norman K., "Economic Costs of Controlling Water Quality Through Management of Irrigation Return Flows," 1976, State of Washington Water Research Center, Washington State University, August.

17) Table 4.1, p. 92, Majoro, Hoeketski, op. cit.

18) Olson, Ted, "Management of Declining Ground-Water Levels in Part of Eastern Washington," in Engineering Geology in Washington, vol. II, 1989, pp. 1015 - 1032.

19) pp. 352-3S3, Gardner, Richard L., and Young, Robert A., "The Effects of Electricity Rates and Rate Structures on Pump Irrigation: An Eastern Colorado Case Study," Journal of Land Economics, Vol. 60, No. 4, November, 1984.

20) p. 358, ibid.

21) "Columbia River Summary Report," op. cit.

22) Returns to agriculture would amount to roughly $2.5 million at current commodity prices and typical crop rotations in the agricultural production area. It would be more cost effective for BPA to simply pay irrigators their typical return ($1.4 million) on this volume of production and provide retraining and relocation assistance to displaced workers.

23) 73,667 Acre Feet of excess water are diverted at Grand Coulee: 73,667 AF x 1,167 cumulative head x 0.87 kWh x 39 mills marginal cost = S2,916,941.

24) Table 3-20, p. 38, "Preliminary Draft, Task 3," op. cit.

25) Section D, vol. 2, "The Role of Electricity in Pacific Northwest Irrigated Agriculture," op. cit.

26) p.1-1, "Modeling Irrigation Conservation and Electrical Demand," 1986, Northwest Economic Associates for BPA.

27) p. 39, "Potential Conservation Opportunities from the Use of Improved Irrigation Scheduling in the Pacific Northwest Region," 1989, Pacific Northwest Labatory for BPA, March.

Footnotes, Page Three

28) Table 8-1, "Marketing Electricity to Industrial Customers: A Study of Pacific Northwest Industries," op. cit.

29) Cf. Tables 28, 37, pp. 19-25, Carlson, John, et al., "The Irrigation Use and Efficiency of Southern Idaho Farmers," 1991, Departments of Agricultural Economics and Rural Sociology, University of Idaho, October.

30) p. 6-33, "Marketing Electricity to Industrial Customers: A Study of Pacific Northwest Industries," op cit.

31) Table 8.2, ibid.

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