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White House Climate Change Task Force

734 Jackson Place, N.W. · Washington, DC 20503

FACSIMILE TRANSMISSION SHEET

To	Meagan	From	Mary
Office		Date	2/24
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Comments: Urgent

Please give to Todd for 1pm mtg.

Pages: 6, including this cover sheet.

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1-Y|

TRIGEN

Trigen Energy Corporation
One Water Street White Plains, New York 10601 • (914) 286-6600 • Fax (914) 948-9157/9190

February 15, 1999

Ms. Geraldine Gerardi, PH.D.
Director, Business Taxation Division
Office of Tax Analysis
U.S. Department of the Treasury
Washington, D.C. 20220

VIA FACSIMILE (202)622-2969

Dear Ms. Gerardi,

Thank you for meeting with me and others from the U.S. Business Council for Sustainable Energy last week to discuss both current application of the tax code to energy generation equipment and the Administration's proposed tax incentives for installation of combined heat and power (CHP) systems. As we discussed, it has become clear that recent legislative and policy initiatives designed to promote installation of CHP and other low-emitting energy generating technologies inadvertently have confused two very different questions. Our meeting was a very helpful step toward sorting out and separately addressing the two related, but different issues, namely:

1) How should tax law and policy be used to promote deployment of energy efficient CHP systems; and,

2) How should tax law and policy related to class lives and depreciation be modified to recognize the new and changing character of modern energy generation equipment?

On the first question, we believe that a tax credit for CHP makes sense as a part of the Administration's programmatic efforts to promote clean energy and reduced air emissions. Tax credits typically operate to obtain public benefits by prompting private parties to make economic choices that they would not as readily make otherwise. As such, a credit would be a good fit for CHP systems, which offer very significant public and private economic and environmental benefits, but can often be more difficult for the private sector to deploy than electric-only projects.

Ms. Geraldine Gerardi, PH.D.
February 15, 1999
Page Two

Despite their inherent fuel-use efficiencies, long-term cost savings and pollution reduction benefits, CHP systems face serious regulatory obstacles that do not confront conventional electric-only plants. In addition, CHP systems generally require a greater initial capital investment and take more time to plan and execute than electric-only projects. A CHP investment tax credit, such as that proposed by the Administration, will provide incentives to private parties to make economic choices that favor timely deployment of the more efficient, environmentally beneficial CHP systems.

On the second issue, we believe that the Federal Government should reevaluate the current class lives and associated depreciation schedules of certain energy generation equipment. Energy generation is changing from a regulated to a competitive business. Technology is changing rapidly. Existing generation technologies are going to be used differently, and new technologies are entering the market. Given these changes, we believe that boilers, turbines, engines, fuel cells and other existing and emerging technologies are not appropriately addressed in current tax laws and regulations.

The physical life and operational patterns of traditional heavy-duty utility equipment is not comparable to that of smaller and lighter equipment, including units that are already in use and others that will be deployed widely as competitive markets emerge. For example, new, small aeroderivative turbines have different physical properties and will generally operate under quite different conditions than large turbine units employed by traditional electric utilities and, consequently, will have different service lives.

Further, the competitive marketplace will force energy suppliers to replace or "upgrade" standing equipment before it begins to fail, since installation of more efficient technology offers lower costs to customers and the opportunity to hold or capture market share for competitive energy suppliers. This inevitable development will compel deployment of new technologies in directions and at paces about which we can only speculate today, albeit with our speculation informed by the observed impacts of competition in other industries. We expect that energy generation equipment will come and go in the marketplace in a manner that strongly resembles that of modern computers -- assets which outlive their economic lives long before they cease to work properly. This is an entirely different situation than the regulated monopoly environment in which economically non-competitive, but physically sound plants remain in service for decades.

It is important and appropriate that the Department of the Treasury recognize that a one-size-fits-all class life for energy equipment is already a flawed approach which will grow increasingly anachronistic by the month. We believe that the Administration's electricity restructuring legislation should address this matter. In this regard, I have enclosed with this letter a draft suggested schedule of class lives for several key modern energy generation technologies. These are our best estimates, though I am sure they would benefit from additional analysis by Treasury and others. We have suggested that, in order to further the Administration's aim of deploying the most efficient technologies possible, the change in class life would only pertain to equipment deployed in energy systems that achieve an overall efficiency target. The Administration's proposed investment tax credit for CHP systems uses a 60% efficiency threshold for smaller CHP projects and a 70% efficiency threshold for larger CHP projects. A similar distinction based on the various class lives might also be appropriate.

Again, thank you for taking the time to meet with me last week. I greatly appreciate your continued interest in and attention to these issues. If I may be of any additional assistance, please don't hesitate to call me at (914) 286-6621.

Sincerely,

Mark C. Hall
Director of Government Affairs
Trigen Energy Corporation

Cc Dirk Forrister, White House Climate Change Task Force
Mark Mazur, U.S. Department of Energy
Dan Reicher, U.S. Department of Energy
David Doniger, U.S. Environmental Protection Agency
David Gardiner, U.S. Environmental Protection Agency
George Frampton, Council on Environmental Quality
Linda Lance, Council on Environmental Quality

Proposed Class Lives of Energy Generation Equipment

The Internal Revenue Code should be amended to include the following assets in the classifications of 5-year, 7-year, and 10-year property if the assets are an integral part of an energy system that achieves an overall efficiency threshold of **X** [*threshold decision subject to further discussion*].

Combustion Turbines

Combustion turbines including microturbines and associated equipment, controls and piping less than or equal to a capacity of 10 Mw in simple cycle or combined cycle mode will have a class life of 5 years

Combustion turbines and associated equipment, controls and piping greater than 10 MW and less than or equal to a capacity of 50 Mw in simple cycle or combined cycle mode will have a class life of 7 years

Combustion turbines and associated equipment, controls and piping greater than 50 MW in simple cycle or combined cycle mode will have a class life of 10 years

Steam Turbines

Steam turbines and associated equipment, controls and piping less than or equal to a capacity of 5 Mw will have a class life of 5 years

Steam turbines and associated equipment, controls and piping with a capacity greater than 5 MW and less than or equal to a capacity of 25 Mw will have a class life of 7 years

Steam turbines and associated equipment, controls and piping with a capacity greater than 25 will have a class life of 10 years

Boilers

Boilers, including heat recovery steam generators, and associated equipment, controls and piping with a capacity less than or equal to 100 mmbtu/hr will have a class life of 5 years

Boilers, including heat recovery steam generators, and associated equipment, controls and piping with a capacity greater than 100 mmbtu/hr and less than or equal to 250 mmbtu/hr will have a class life of 7 years

Boilers, including heat recovery steam generators, and associated equipment, controls and piping with a capacity greater than 250 mmbtu/hr will have a class life of 10 years

Fuel Cells

Fuel Cells and associated equipment, controls and piping less than or equal to a capacity of 1 Mw in simple cycle or combined cycle mode will have a class life of 5 years

Fuel Cells and associated equipment, controls and piping greater than 1 MW and less than or equal to a capacity of 5 Mw in simple cycle or combined cycle mode will have a class life of 7 years

Fuel Cells and associated equipment, controls and piping greater than 5 MW in simple cycle or combined cycle mode will have a class life of 10 years

Reciprocating Engines

Reciprocating engines and associated equipment, controls and piping less than or equal to a capacity of 2.5 Mw in simple cycle or combined cycle mode will have a class life of 5 years

Reciprocating engines and associated equipment, controls and piping greater than 2.5 MW and less than or equal to a capacity of 5 Mw in simple cycle or combined cycle mode will have a class life of 7 years

Reciprocating engines and associated equipment, controls and piping greater than 5 MW in simple cycle or combined cycle mode will have a class life of 10 years

Agenda for NEC Deputies Meeting
Electricity Restructuring
February 24, 1999

1) **Treatment of the Power Marketing Administrations' Non-Recoverable Costs**

Should BPA, WAPA and SWAPA be permitted to impose surcharges on their transmission services as a substitute for the existing stranded cost recovery mechanism to recover costs of generation?

2) **Permit Uniform Depreciation for Distributed Power Capital Equipment**

Should depreciation schedules be revised to for efficient and environmentally-preferred DP technology?

3) **Assistance to Indian Tribes**

a) Should the bill authorize the creation of electricity infrastructure grants to Indian tribes?

b) Should the bill contain investment tax credits for the building of generation plants on Indian reservations?

4) **Adjustment Assistance for Displaced Workers**

Should a new retraining program for electrical workers be created at the Department of Labor, or are existing programs sufficient to meet their needs?

5) **Grants to Promote Remote Power Generation**

How can the electricity needs of remote communities be addressed?

MODIFIED RENEWABLE PORTFOLIO STANDARD PROPOSAL

- Minimum amount of non-hydroelectric renewables in 2010 increases from 5.5% to 7%.

What impact on MTC?

- Maintain 1.5 cents/kwh price cap for purchase of RPS credits.

- Retain $20 billion in savings produced by Administration's Comprehensive Electricity Competition Act:

  – Funds from RPS credit sales would continue to be deposited in the Public Benefit Fund.

  – Public Benefit Fund wires charge, as provided in the legislation, would be adjusted to maintain $3 billion level (plus inflation).

3-5 mmTC per each extra percentage point of RPS

THE WHITE HOUSE

WASHINGTON

February 22, 1999

MEMORANDUM FOR DISTRIBUTION

FROM: Gay Joshlyn, National Economic Council

SUBJECT: Deputies Meeting on Energy Deregulation 1:00 pm mtg.

I would like to confirm that there will be a NEC Deputies meeting to discuss energy deregulation **Wednesday, February 24th at 1:00 pm in OEOB Room 180.** Please call me at 456-2800 if you have any questions or if you need to have someone cleared into the building.

DISTRIBUTION

Jeff Frankel, CEA	5-6958
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Richard Rominger, USDA	720-5437
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Todd Stern, WH	6-2215
David Hayes, DOI	208-5956

Carbon

- DOE Stds for perform—

- Stranded cost consid'n include job loss

THE WHITE HOUSE

WASHINGTON

MEMORANDUM FOR NEC DEPUTIES

FROM: Ronald E. Minsk

SUBJECT: Department of Energy's Recommended Modifications to the Administration's Electricity Restructuring Bill

DATE: February 22, 1999

In January and February 1999, the National Economic Council (NEC) led an interagency process to review the Department of Energy's (DOE) recommended modifications to the Administration's electricity restructuring bill. This memo provides the background necessary for the NEC Deputies to address most of the issues that the agencies could not resolve at the staff level. This memo does not address certain unresolved issues related to the Tennessee Valley Authority. This memo also does not address issues that were resolved last year. Nor does it address a recently raised new issue involving a power plant energy efficiency standard, which the working group has not yet addressed.

I. Background: The Department of Energy's Last Electricity Restructuring Bill and the NEC Interagency Process

In June, 1998, following a lengthy interagency review coordinated by the NEC, DOE submitted an electricity restructuring bill to Congress. The bill was intended to create the federal framework necessary to facilitate the development of competitive wholesale and retail markets for the generation of electricity. Although competitive retail markets are beginning to develop at the state level, they will not be able to achieve maximum efficiencies without modification to the federal framework under which they operate. The 105th Congress did not act on the Administration's bill before adjourning.

In late December, 1998, DOE submitted to the NEC for interagency review a memorandum summarizing additions that DOE proposed including in an updated version of the Administration's bill to be sent to the 106th Congress. Although DOE proposed additions to last year's bill, it did not propose changes to issues that were resolved within the Administration last year. The NEC organized several interagency meetings at which each proposed addition to last year's bill was discussed. Because so little time had elapsed since last year's bill was drafted, and because several issues required many months to resolve during the previous interagency review, the NEC decided at the outset of the process that it would not reopen issues that were resolved at the interagency level last year.

Following a series of meetings held in January and February, the NEC has identified five issues that cannot be resolved at the staff level. Accordingly, the NEC presents the following five issues for consideration by the NEC Deputies:

- The treatment of "non-recoverable" costs incurred by the Bonneville Power Administration and other federal power marketing administrations;
- The advisability of creating an infrastructure grant program and tax credits to help Indian tribes benefit from competitive markets;
- The modification of the depreciation schedule in the tax code to promote the development of a distributed power industry;
- The creation of a retraining program for displaced workers; and,
- The creation of a grant program to promote electrification of remote communities.

II. <u>Discussion of Unresolved Issues</u>

A. <u>Issue #1: Treatment of the Power Marketing Administrations' Non-Recoverable Costs</u>

The Bonneville Power Administration (BPA) markets wholesale electrical power generated at federal dams, and operates and markets transmission services in the Pacific Northwest. BPA serves a 300,000 square mile area including Oregon, Washington, Idaho, Western Montana, and parts of Northern California, Nevada, Utah and Wyoming. About 40 percent of all the power consumed in the Pacific Northwest is marketed by BPA. In addition, BPA's transmission system exceeds 15,000 circuit miles, provides more than three-fourths of the region's high-voltage transmission capacity, and includes major transmission links with Canada and other regions within the United States.

BPA operates on a non-appropriated, self-financing basis. BPA deposits its revenue from ratepayers directly into a revolving fund from which it pays its costs. It repays outstanding loans from Treasury only after meeting its other financial obligations. BPA is required by law to sell electricity at cost, which is currently between ten and fifteen percent below the prevailing market price. The market is volatile, however, and only two years ago BPA's costs were above market.

BPA's rates currently are developed through a formal regional process pursuant to certain ratemaking standards. Those standards require BPA to establish separate power and transmission rates that enable it to repay "the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs." Among the costs that have caused BPA rates to rise in recent years are costs that are attributable to efforts to mitigate the destruction of habitat of fish and wildlife populations in the Columbia River basin, and the repayment of approximately $7 billion in Washington Public Power Supply System (WPPSS) embedded costs that BPA incurred in partnership with many of its customers in the Northwest to construct three nuclear power plants.

Unlike most costs faced by utilities, BPA has no control over its future fish and wildlife costs, which are estimated to range from the current annual cost of $438 million up to $721 million annually for the 2002-2006 period, a potentially significant cost increase. As noted above, however, BPA's current rates are about ten to fifteen percent below market rates. BPA estimates that the difference between sales at cost and the prevailing market price is between $100 to $250 million, although OMB believes revenues could be increased by $300 to $400 million annually if BPA sold power at market based rates. Accordingly, under most estimates of future market conditions, BPA should be able to recoup all of its current costs and may be able to pay most if not all of the additional environmental costs with its revenues from generation.

If, however, unexpectedly low prices or high costs force BPA's costs above the market price, BPA could seek to implement a surcharge on transmission to collect the shortfall in generation revenues. BPA could petition the Federal Energy Regulatory Commission (FERC) for embedded stranded cost recovery, which would review such a request and may or may not approve it. FERC, however, does not treat losses related to investments in the future as stranded costs. Therefore, BPA seeks through this bill clear legislative authority to impose a surcharge on its transmission services if necessary to raise the funds to meet its loan payments to Treasury. Because a surcharge could lead to a lack of fiscal constraint, BPA further proposes that the transmission surcharge have an associated annual and total limit and a sunset provision.

A similar issue applies to the Western Area Power Administration (WAPA) and the Southwestern Area Power Administration (SWAPA). Specifically, WAPA and SWAPA may also face increasing environmental costs that push the cost of providing electricity above the market price. Accordingly, they too seek authority to impose a surcharge on transmission services, if necessary to meet environmental costs. Whatever solution is identified for BPA should also apply in a similar manner to the other power administrations in the interest of achieving consistent treatment for all power marketing administrations.

Unresolved Issue: In a competitive electricity market, BPA, WAPA and SWAPA will not be able to sell power at prices exceeding the market price for electricity. If their "non-recoverable" costs push the total cost of power above the market price, should BPA, WAPA and SWAPA be permitted to impose surcharges on their transmission services as a substitute for the existing stranded cost recovery mechanism to recover costs of generation?

Option #1 (DOE Proposal): Permit BPA to impose a surcharge on transmission services to recover "non-recoverable" costs of generating electricity, subject to a cap of $100 million annually and $600 million between 2001 and 2016.

Option #2: Do not permit BPA to impose a surcharge on transmission services to recover "non-recoverable" costs of generating electricity.

DOE/BPA Position: DOE/BPA supports Option 1. DOE believes that the bill should enhance and clarify BPA's authority to recover "non-recoverable" generation costs through a surcharge on BPA's transmission customers. The surcharge would be treated as a loan from BPA's transmission customers to BPA's generation customers that would be paid back when generation costs fall below market prices. Moreover, the idea of imposing a surcharge on transmission was developed by the Pacific Northwest Governor's Transition Board (the "Transition Board"), and thus it has political support in the region. DOE believes that the surcharge should be capped at the same level proposed by the Transition Board ($100 million annually and $600 million total). The authority to impose the surcharge should expire in 2016, after BPA's WPPSS debt is retired.

BPA does not support the establishment of a sinking fund to fund future fish and wildlife mitigation costs, because it is required by law to sell electricity at cost, and BPA believes that deposits to a sinking fund are not current costs. Moreover, there are significant issues associated with making a decision now about pre-collecting for future costs given the extremely controversial and ongoing discussions regarding the potential for breaching the Lower Snake River Dams. Specifically, were BPA to pre-collect for future costs, it would be viewed as a signal that BPA expected the government to breach the dams, a decision that has not yet been made.

DOI/DOC Position: DOI and DOC also support option 1. In the Fish and Wildlife Funding Principles announced last fall, BPA committed to meeting its future fish and wildlife obligations. Vice President Gore endorsed the principles and BPA's commitment to fund its fish and wildlife costs associated with the hydropower system in the Columbia and Snake River Basins. Given the substantial uncertainties associated with potential fish and wildlife costs, as well as uncertainties about future market conditions, it is essential that BPA have the authority to impose a transmission surcharge. This cost recovery mechanism is necessary to provide BPA the flexibility that it needs to meet the full range of its potential costs. The Departments of the Interior and Commerce are prepared to accept a cap on the transmission surcharge mechanism, in keeping with the proposal offered by the Transition Board. It is our understanding that the proposed cap -- $100 million annually, $600 million total -- reflects input from a public process that was conducted in the region.

CEA/Treasury/OMB Position: There is no need to grant BPA special legislative authority to impose a surcharge on transmission services. If BPA's environmental costs rise so that its current generation revenues cannot cover its costs, BPA may petition FERC for stranded cost relief under sections 205 and 206 of the Federal Power Act. These sections coupled with existing BPA repayment authorities provide sufficient protection for the Federal Treasury while providing funds to meet fish and wildlife obligations.

Although FERC might not treat future fish and wildlife costs as stranded costs under the Federal Power Act, the $7 billion in WPPSS debt guaranteed by BPA appears to fit FERC's definition of stranded costs. If so, FERC could permit BPA to impose a transmission surcharge, targeted to those customers that contracted with BPA to build the WPPSS plants. This relief should permit BPA to meet its costs. In the event that BPA would be unable to cover its generation costs after a FERC decision on stranded costs, it would be preferable to permit BPA to delay its payments to Treasury rather than allowing BPA to impose a surcharge on all transmission services.

BPA should not be permitted to impose a surcharge on transmission services to pay for "non-recoverable" costs of generation. BPA has transmission customers from outside the Northwest region who do not purchase electricity (generation) from BPA. A transmission fee would shift costs from the Northwest region to those other customers, who have neither caused the costs to be incurred nor received any benefit from Northwest generation. For example, if Alberta utilities sold power to Southwestern customers they would be paying for the costs caused by Northwestern entities. A simple tax would be a more equitable mechanism, if we intend to shift the costs out of the region.

In order to insure against future fish and wildlife costs increasing BPA's generation costs above market prices, BPA should add to existing reserve funds. Additional contributions to the reserve could be limited to specific amounts per year with an overall limit that is based on the probability that a specific amount may be needed to cover fish and wildlife costs. BPA already carries reserves of about $600 million to compensate for uncertainty associated with droughts, fluctuating market conditions and other factors. Currently, BPA's rates are well below market rates, leaving substantial room ($300 to $400 million annually) to fund additions to reserves. The Fish and Wildlife Funding Principles committed BPA to seek to achieve an 88 percent probability of Treasury payment in full and on time. BPA can meet this requirement by including in its rates an adequate reserve to deal with these uncertainties.

OMB notes that under the DOE Position, the Pacific Governor's Transition Board recommended allowing a surcharge on transmission only after several other alternative mechanisms are exhausted and costs continue to increase above market.

DOJ Position: DOJ believes that the bill should include a mechanism for BPA to recover its fish and wildlife and other stranded costs. However, such a mechanism should function in a competitively neutral manner to the fullest extent possible.

B. Issue #2: Permit Uniform Depreciation for Distributed Power Capital Equipment

Distributed power (DP) is any small-scale power generation technology that is intended to serve a discrete set of consumers at a site closer to the consumers than a central generation station. While the size of central generation stations typically range from 200 MW to 1,200 MW, distributed power is generally substantially smaller. Small low-cost modular generators include fuel cells, gas turbines, and micro turbines, as well as combustion engines, wind, photovoltaics, and small-scale hydropower.

Distributed power offers numerous benefits. First, because it is sized to satisfy a single user's on-site requirement or to serve a group of users close to the source, costly upgrades to the transmission and distribution systems can be avoided. Second, generating power at the site where it is used could be more efficient when there are not significant economies of scale in generation because it avoids energy losses that occur along transmission and distribution lines. Third, distributed power enables large commercial and industrial customers to shave their peak power needs, thereby reducing their costs while providing reliability benefits to all users of the transmission and distribution systems. Fourth, distributed power provides substantial environmental benefits through the introduction of cleaner, more efficient technologies. Finally, distributed power can provide customers with standby, emergency power or high-quality uninterruptible power for critical applications.

Unresolved Issue: Should depreciation schedules be revised to for efficient and environmentally-preferred DP technology?

Option #1 (DOE Proposal): All equipment used in distributed power facilities would have a tax life of 7 years for purposes of depreciation.

Option #2: Do not adjust depreciation schedules applicable to distributed power facilities unless further review indicates that it is warranted.

DOE Position: Significant uncertainty with respect to the tax treatment of distributed power facilities discourages their use in many applications. Within the DP industry, there is a general perception that DP equipment is subject to depreciation over 39 years. For certain pieces of equipment, such as turbine engines, a 39 year asset class life is significantly longer that when the same equipment is used in other applications, such as airplane propulsion, even though the actual lives of the assets are significantly shorter when used in DP applications than when used in those other applications. In order to eliminate this uncertainty, and promote the development of a DP industry, all DP equipment should be depreciated over seven years. Although Treasury notes that any uncertainty could be eliminated by an Internal Revenue Service (IRS) Private Letter Ruling, such rulings have no precedential value, and cannot be relied upon to eliminate uncertainty throughout an industry.

EPA Position: EPA supports DOE's position regarding accelerated depreciation of DP capital equipment. EPA believes that existing depreciation schedules create an unnecessary barrier to investments in these highly efficient generating technologies and are inequitable given the evidence that the DP assets depreciate more readily that many other types of industrial actions. EPA also believes that there will substantial societal benefit from the development of DP systems over time and that the Administration should facilitate this valuable technological change in the electric power industry. Governmental assistance will demonstrate tangibly that the Administration supports progressive, clean innovative energy technologies for the benefit of the public in the future when they hold considerable promise.

Treasury/OMB Position: Asset class lives for depreciable property should be based on actual useful lives of the capital, and should not be adjusted to promote the use of favored technologies. Rather, class lives and recovery periods should be determined so as to produce appropriate measures of net income. In order for Treasury to support an alteration in class lives, the Department has always required that conclusive evidence supporting the change be demonstrated. However, sufficient data needed to support a seven-year recovery period for DP equipment has not been presented. In addition, the determination of an appropriate class life for DP equipment raises other important issues concerning the scope of asset class definitions, proper methods of assigning assets to the various depreciation asset classes, and the setting of appropriate class lives. Such issues will be considered and discussed by Treasury in its mandated depreciation report to Congress, due in March, 2000. It is inappropriate to prejudge the report's conclusions at the present time by advocating a change in the lives for DP property. Moreover, Treasury does not believe that current depreciation schedules create a strong disincentive for investments in DP systems. Rather, those disincentives are to be found in certain environmental and other regulatory barriers. Finally, Treasury believes that any uncertainty with respect to the appropriate class life of DP equipment could be resolved through an IRS Private Letter Ruling.

C. Issue #3: Assistance to Indian Tribes

The Administration's bill encourages states to adopt retail competition to improve generation efficiency, lower electricity costs, and improve the environment. In drafting the bill, DOE was concerned that restructuring the electric industry likely will have a mixed impact on Indian tribes, and that some Indian tribes might not be able to fully realize these benefits. As part of its attempt to address the needs of Indian tribes, DOE included in its draft bill a grant program through which DOE could provide tribes with assistance, in consultation with the Secretaries of the Interior and Agriculture, in analyzing tribal electricity needs, the availability of natural resources for electricity generation, opportunities for transmission enhancement/construction, and effects of state restructuring programs on tribal electricity supplies. DOE's bill also authorizes electricity infrastructure grants to Indian tribes.

In addition to including provisions in the bill to ensure that Indian tribes can obtain benefits from restructuring as consumers of electricity, DOE proposed including in the bill an investment tax credit for the builders of electricity generating plants and other facilities that are used for sales to non-tribal customers.

Unresolved Issue #1: Should the bill authorize the creation of electricity infrastructure grants to Indian tribes?

Option #1 (DOE Proposal): Authorize the creation of electricity infrastructure grants to Indian tribes. Such a program would be managed by DOE in consultation with the Department of the Interior and the Department of Agriculture's Rural Utility Service (RUS).

Option #2: Do not authorize the creation of electricity infrastructure grants to Indian tribes.

DOE Position: The electricity restructuring bill should include authorization for infrastructure grants for Indian tribes. This provision will ensure that tribes can obtain benefits as consumers in the restructured electricity market. Some tribes, or portions of tribes, do not have access to the electric grid due to a lack of infrastructure. RUS loans are insufficient because RUS will not issue loans without a guarantee of a pay back. If the existing RUS loan program were sufficient, we would not have the problem we see today.

DOI Position: The Department of the Interior strongly supports the inclusion of an infrastructure grant program to ensure that Indian tribes benefit from the transition to retail electric competition. An infrastructure grant program will provide tribes that currently lack access to the electric grid with opportunities not now available to plan for and invest in the infrastructure necessary for the generation, transmission and distribution of power to serve tribal needs. Without such assistance, many tribes will be denied access to the benefits provided by this legislation.

OMB Position: OMB opposes the proposed grant program for the following reasons: 1) RUS already provides low-interest loans for distribution infrastructure which is available to

Indian tribes; 2) the government should not be in the business of subsidizing new transmission capacity anywhere; 3) the size of the grant program is so small that, even if matched, it is unlikely to be sufficiently large to pay for anything useful; and, 4) the Internal Revenue Code already includes tax incentives for investments on reservations that are under-utilized.

Unresolved Issue #2: Should the bill contain investment tax credits for the building of generation plants on Indian reservations?

Option #1 (DOE Proposal): Include tax credits in bill.

Option #2: Do not include tax credits in bill.

Option #3: Include tax credits and/or a provision for tax exempt development bonds in the bill.

DOE Position: The electricity restructuring bill should include investment tax credits for the construction of new generation capacity on Indian reservations that will serve non-Indian areas. This provision will ensure that tribes can obtain some of the economic benefits available in a restructured electricity market.

DOI Position: The electricity restructuring bill should include a provision to enable tribes to participate as new entrants in competitive electricity markets. DOI supports the proposal for tax credits for the building of generation plants on Indian reservations but also recommends tax exempt development bonds as another, potentially more effective mechanism to achieve the outlined goal of ensuring that tribes can more fully participate in the restructured electricity market. Tax exempt bonds issued by tribes would provide the capital to build tribally-owned facilities rather than requiring tribes to depend on non-Indian companies for on-reservation economic development.

The opportunity to participate in the competitive electricity market will help encourage economic development on tribal land. In an Executive Memorandum issued in August, 1998, "Economic Development in American Indian and Alaska Native Communities," the President called on federal agencies to coordinate and strengthen existing Native American economic development initiatives. In keeping with the President's directive and with the federal government's trust responsibility to Indian tribes, it is appropriate and necessary for the United States to take steps, such as those proposed in this legislation, to foster tribal economic development opportunities as well as to ensure that tribes have an opportunity to participate on an equal footing in a deregulated electricity market.

USDA/RUS Position: If a tax credit is established, it should not subsidize the construction of new generation capacity that will compete with any entity that has loans outstanding to RUS.

EPA Position: EPA opposes tax credits for investments in power facilities on Indian reservations. EPA is believes that this provision might increase CO_2 emissions, thereby increasing the cost of compliance with international agreements on climate change. Given the availability of substantial coal resources on some Indian reservations, the lure of large tax credits might encourage the construction of otherwise uneconomic coal-fired plants which have significantly higher CO_2 emissions than other alternatives.

OMB Position: The record shows that the private sector has been willing to invest heavily to build generation capacity on Indian land. Moreover, the government should not be in the business of subsidizing new powerplant capacity anywhere. Non-Indian investors would be the principal beneficiaries because Tribes are normally exempt from Federal income tax. There is no evidence that energy investment is a promising way to stimulate economic development in Indian country.

Treasury/CEA Position: The tax code already contains specific provisions (expiring after 2003) designed to encourage business activity in tribal areas, including tax credits for wages paid to Indians employed on a reservation and accelerated depreciation for property used in a trade or business in an Indian reservation, including power plants. DOE's proposal would favor investments in power plants over other more productive investments that have less favorable tax treatment. If the goal is economic development, the Administration's FY 2000 budget proposal for a new tax credit to encourage business activity in low-income communities (including Indian reservations) is preferable. This incentive is available for both equity investments and loans to certain businesses, and is not limited to power plants.

The Administration's position, reiterated in the Budget, regarding the use of tax-exempt bonds for electric facilities is that no new tax-exempt bonds should be issued for either generation or transmission facilities. Proposing an exception for facilities on Indian reservations, either tribally or privately owned, would unlevel the competitive playing field in a deregulated industry. Tax-exempt bonds are an inherently inefficient subsidy mechanism because of the windfalls they provide to high-bracket taxpayers. Revenue losses to the federal government exceed interest savings to issuers of bonds. The continuation of tax-exempt financing on reservations would encourage State and local governments in their efforts to maintain access to tax-exempt bonds for generation and transmission facilities.

D. Issue #4: Adjustment Assistance for Displaced Workers

During a previous attempt by the Administration to draft an electricity restructuring bill, the labor unions told the Administration that they did not want the issue of displaced workers addressed at the federal level. In the interim, however, the International Brotherhood of Electrical Workers and the AFL-CIO have changed their positions, and have requested that the Administration provide generous guarantees and benefits for those workers that might lose their jobs as a result of electricity restructuring.

In response to union concerns, DOE seeks the creation of a program at the Department of Labor (DOL) to address the specific needs of workers that lose their jobs as a result of electricity restructuring.

Unresolved Issue: Should a new retraining program for electrical workers be created at the Department of Labor, or are existing programs sufficient to meet their needs?

Option #1 (DOE Proposal): Create a new program for displaced electricity workers at DOL that provides a level of benefits that exceeds that available to other displaced workers.

Option #2: Do not create any new program for workers displaced by electricity restructuring. Sufficient programs already exist at DOL to address the workers' needs.

DOE Position: Labor unions have indicated to DOE that existing displaced worker training programs do not provide sufficient benefits to displaced workers. Therefore, DOE seeks the creation of a special program for workers displaced by electricity restructuring.

DOL Position: A decision to treat workers affected by electricity restructuring in the same manner as other displaced workers may not satisfy the wishes of unions that the bill provide adequate benefits for displaced workers.

OMB/Treasury Position: The bill should not authorize a new categorical dislocated worker program in any agency. The displaced worker program located at DOL, recently reauthorized in the Workforce Investment Act of 1998, provides training and reemployment services to workers without regard to the cause of their dislocation. The FY 2000 Budget proposes an additional $190 million above FY 1999 level of $1.4 billion for this program, and puts the program on a five-year funding path for a universal program serving roughly 2 million individuals annually, or every dislocated worker who wants and needs assistance. A new categorical program for displaced energy workers is unnecessary and inconsistent with the FY 2000 Budget policy.

DOL possesses the greatest level of expertise in designing and operating adjustment assistance programs. The bill could simply direct displaced workers to DOL to obtain generally available assistance for all displaced workers, or require utility companies undergoing significant worker restructuring to submit advance written notice to workers and to the State Rapid Response Unit. In addition, DOL and DOE could sign a Memorandum of Understanding to identify any areas of special need and quickly provide targeted discretionary grants to aid energy workers from the Secretary's twenty percent national reserve. DOL is participating in a similar interagency agreement to aid workers and communities affected by logging restrictions in the Pacific Northwest designed to protect the North Spotted Owls.

E. Issue #5: Grants to Promote Remote Power Generation

The Administration's bill is expected to provide significant benefits to electricity consumers connected to the three major power grids that serve the continental United States by accelerating the transition to competitive electricity markets. However, a strong argument can be made that the first comprehensive overhaul of the federal statutory framework for the electricity industry in over 60 years should provide the economic and environmental benefits of improved electricity service and technology to all customers, irrespective of location.

In this regard, the situation of remote communities not connected to the major power grids merits particular attention. Communities that are not connected to the grid also face high costs and environmental concerns, which together can pose a significant barrier to economic development. Many clean and efficient generation technologies are becoming available for small off-grid or end-of-line loads. These include small gas turbines, fuel cells and renewables such as solar, wind and small hydropower. These distributed power technologies can provide small remote communities with a source of clean, affordable electric power. The deployment of such technologies can also serve as a model for their use in more populated areas faced with distribution constraints, where power quality is an important concern, or where combined heat and power can produce both cost savings and environmental benefits.

Unresolved Issue: How can the electricity needs of remote communities be addressed?

Option #1 (DOE Proposal): Authorize electrification grants for remote communities, to be funded through annual appropriations. The proposed program would be managed by the RUS, in consultation with DOE.

Option #2: Do not authorize grants for remote communities.

DOE Position: To help residents of remote areas, the bill should authorize appropriations for grants to address the electricity needs of small, remote communities that are not connected to the national transmission grid, or where costly transmission or distribution reinforcements are needed to serve growing loads. Such communities frequently are forced to rely upon expensive, older, polluting, generation technologies and would not benefit from provisions included in the original Administration proposal because they do not have the option of importing less expensive, cleaner electric power through the interconnected grid.

In order to qualify for grants, a community would have to demonstrate that it is not connected to the national transmission grid or has limited or constrained connections and that the cost of power in the community exceeds 150 percent of the national average cost of power. The community could be any recognizable local government or Indian tribe of not more than 10,000 individuals. Senate Minority Leader Daschle and Energy Committee Chairman Murkowski co-sponsored a similar proposal in the last Congress.

OMB Position: OMB opposes the creation of a new program to provide grants to rural communities, because the RUS already provides low-interest loans for distribution infrastructure to such communities. Moreover, OMB did not find DOE's justification for this program persuasive.

Electricity Restructuring

DRAFT MEMORANDUM FOR NEC DEPUTIES

FROM: Ronald E. Minsk

SUBJECT: Department of Energy's Electricity Restructuring Bill

DATE: February ??, 1999

In January and February 1999, the National Economic Council (NEC) led an interagency process to review issues for inclusion in a draft bill to restructure the electricity generation market. This memo provides the background necessary for the NEC Deputies to address those issues that the agencies could not resolve at the staff level.

I. Background: The Department of Energy's Last Electricity Restructuring Bill and the NEC Interagency Process

In June, 1998, following a lengthy interagency review coordinated by the NEC, the Department of Energy (DOE) submitted an electricity restructuring bill to Congress. The bill was intended to create the federal framework necessary to facilitate the development of competitive markets for the generation of electricity. Although such markets are beginning to develop at the state level, they will not be able to achieve maximum efficiencies without modification to the federal framework under which they operate. Congress did not act on the Administration's bill last year.

In late December, 1998, DOE submitted to the NEC for interagency review a memorandum summarizing changes that DOE proposed including an updated version of its bill. Although DOE proposed additions to last year's bill, it did propose changes to issues that were resolved within the Administration last year. The NEC organized several interagency meetings at which each modification to last year's bill was discussed. Because so little time had elapsed since last year's bill was drafted, and because several issues required many months to resolve during the previous interagency review, the NEC decided at the outset of the process that the we would not reopen issues that were resolved at the interagency level last year in the current interagency review.

Following a series of meetings held in January and February, the NEC has identified five issues that cannot be resolved at the staff level. Accordingly, the NEC has identified the following five issues for consideration by the NEC Deputies:

- The treatment of "non-recoverable" costs incurred by the Bonneville Power Administration;
- The advisability of creating special programs to assist Indian tribes;
- The modification of depreciation schedule in the tax code to promote the development of a combined heat and power/distributed generation industry;
- The review of mergers between cooperatives of municipal power companies financed by the Rural Utility Service (RUS) with regard to the mergers regard on competitive markets; and,
- The creation of retraining programs for displaced workers.

II. Discussion of Unresolved Issues

A. Treatment of the Public Power Administration's Non-Recoverable Costs

The Bonneville Power Administration (BPA) markets wholesale electrical power generated at federal dams, and operates and markets transmission services in the Pacific Northwest. BPA serves a 300,000 square mile area including Oregon, Washington, Idaho, Western Montana, and parts of Northern California, Nevada, Utah and Wyoming. About 40 percent of all the power consumed in the Pacific Northwest is marketed by BPA. In addition, BPA's transmission system exceeds 15,000 circuit miles, provides more than three-fourths of the region's high-voltage transmission capacity, and includes major transmission links with Canada and other regions within the United States. BPA has many public responsibilities in addition to the distribution of federal power, including the mitigation of fish and wildlife losses in the Columbia River and its tributaries and complying with the Endangered Species Act and the National Environmental Policy Acts.

BPA's rates currently are developed through a formal regional process pursuant to certain ratemaking standards that require BPA to establish power and transmission rates to repay "the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs." These other costs include amounts attributable to efforts to mitigate and enhance fish and wildlife populations in the Columbia River basin, which currently exceed $400 million annually, and over $7 billion in Washington Public Power Supply System and other BPA-backed debt. At the end of Fiscal Year 1997, BPA's outstanding Treasury repayment obligations exceeded $7.6 billion. BPA operates on a non-appropriated, self-financing basis. BPA deposits its revenue from ratepayers directly into a revolving fund for payment of its costs. It repays Treasury only after its other financial obligations are met.

Under FERC's definition of stranded costs, a utility may recover as stranded costs only historical embedded costs. Losses for future investment do not satisfy the definition of stranded costs because utilities presumably have control over their investments once retail competition is introduced. Unlike other utilities, however, BPA has a significant future cost variable over which it has no control --- fish and wildlife costs, which are estimated to range from $438 to $721 million annually for the 2002-2006 period.

Even after electricity restructuring, BPA will continue selling electricity at cost, which is currently about twenty percent below market rates. BPA wants to ensure, however, that should its fish and wildlife mitigation costs increase its cost of generating electricity above the market price of power, that it can recover sufficient funds to repay its debt to Treasury. Under most estimates of future market conditions, BPA is expected to be able to recoup all of its costs. However, if power prices unexpectedly fall below BPA's prices, or if BPA's costs rise unexpectedly rise by a substantial amount, BPA would need a cost recovery mechanism in order to raise the funds to meet its loan payments to Treasury.

The same issue applies to the Western Area Power Administration (WAPA) and the Southwest Area Power Administration (SWAPA). Accordingly, whatever solution is developed for BPA should also apply to the other power administrations.

Unresolved Issue: Should BPA, WAPA and SWAPA be permitted to place surcharges on their transmission services to recover "non-recoverable" costs of generation that raise their costs of generating electricity above the prevailing market price?

Option #1: Permit BPA to impose a surcharge on transmission services to recover "non-recoverable" costs of generating electricity, subject to a cap of $50 million annually and $400 million between 2001 and 2016.

Option #2: Permit BPA to impose a surcharge on transmission services to recover "non-recoverable" costs of generating electricity, subject to no cap.

Option #3: Do not permit BPA to impose a surcharge on transmission services to recover "non-recoverable" costs of generating electricity.

CEA/Treasury/OMB Position: BPA should not be permitted to impose a surcharge on transmission services to recover costs related to the generation of electricity. Such a surcharge amounts to an involuntary subsidy from (generally captive) transmission customers to generation customers, and will distort the transmission market and may prevent competition in generation. Instead of imposing a surcharge on transmission customers once its generation costs rise above the market price of power, BPA should establish a sinking fund prior to the occurrence of high fish and wildlife mitigation costs that will enable BPA to meet its costs with saved funds. If such costs do not arise, the money may be refunded to BPA's generation customers in the form of lower rates. In this manner, there will be no subsidy of generation customers by transmission customers, and the transmission market will operate free of distortion.

NOAA/FWS Position: BPA should be permitted to impose a surcharge on transmission services to recover costs related to the generation of electricity, if its fish and wildlife mitigation costs rise such that the cost of generation exceeds the market price. The surcharge should not be subject to any cap, because it would be difficult to fund fish and wildlife mitigation costs that exceed the cap.

DOE Position: BPA should be permitted to impose a surcharge on transmission services to recover costs related to the generation of electricity if its fish and wildlife mitigation costs rise such that the cost of generation exceeds the market price. The surcharge would be treated as a loan from transmission to geneation which would be paid back when generation costs fall below market prices. BPA's surcharge should, however, be subject to a $400 million cap between 2001 and 2016 to limit the exposure of BPA's transmission customers. Failure to establish a cap would be tantamount to the establishment of an unlimited fund to address undefined environmental costs. Such a plan would be unwise, and would not attract necessary political support.

BPA does not support the establishment of a sinking fund to fund future fish and wildlife mitigation costs, because it wants to sell electricity at cost, and BPA believes that deposits to a sinking fund are not current costs. Moreover, the Pacific Northwest governors and Congressional delegations support BPA's continued sale of cost based power to the region, and do not support the price hikes that would result from the creation of a sinking fund.

Although WAPA and SWAPA have responsibilities in different regions (and on different rivers), the underlying issue, the appropriate mechanism to fund unexpectedly high wildlife/environmental mitigation expenses, is the same. Accordingly, whatever mechanism is adopted for BPA should also be adopted for WAPA and SWAPA, subject to appropriate caps, if applicable.

B. Permit Accelerated Depreciation for Distributed Power Capital Equipment

Distributed power (DP) is any small-scale power generation technology that is intended to serve a discrete set of consumers at a site closer to the consumers than a central generation station. While the size of central generation stations typically range from 200 MW to 1,200 MW, distributed power is generally substantially smaller. Small low-cost modular generators include fuel cells, gas turbines, and micro turbines, as well as combustion engines, wind, photovoltaics, and small-scale hydropower.

Distributed power offers numerous benefits. First, because it is sized to satisfy a single user's on-site requirement or to serve a group of users close to the source, costly upgrades to the transmission and distribution systems can be avoided. Second, generating power at the site where it is used is more efficient because it avoids energy losses that occur along transmission and distribution lines. Third, distributed power enables large commercial and industrial customers to shave their peak power needs, thereby reducing their costs while providing reliability benefits to all users of the transmission and distribution systems. Fourth, distributed power provides substantial environmental benefits through the introduction of cleaner, more efficient technologies. Finally, distributed power can provide customers with standby, emergency power or high-quality uninterruptible power for critical applications.

While retail competition itself will provide an important impetus to the development of DP systems, the current depreciation schedules for DP systems are a strong disincentive for their use. DOE's draft bill removes the tax disincentive for DP technology.

Unresolved Issue: Should depreciation schedules be revised to eliminate existing biases against efficient and environmentally-preferred DP technology?

Option #1 (DOE Proposal): All equipment used in distributed power facilities would have a tax life of 7 years for purposes of depreciation. This approach would be roughly consistent with the treatment of comparable equipment used in industry-specific asset classes.

Option #2: Do not adjust depreciation schedules applicable to distributed power facilities unless further review indicates that it is warranted.

DOE Position: The present tax code treatment of distributed power facilities discourages their use in many types of applications. Depreciation lifetimes for particular pieces of equipment, such as turbine engines, are typically much longer when the equipment is used as part of a DP facility than when it is used in another application, such as airplane propulsion. For instance, when DP equipment is used in commercial buildings, they are treated as structural components and are therefore subject to straight-line depreciation over a 39 year lifetime. In order to promote their use, installed DP facilities should be depreciated over seven years.

Treasury Position: Useful lives for the purpose of depreciating capital should be based on the actual useful lives of the capital, and should not be adjusted to promote the use of favored technologies. If the useful lives that are currently applicable to DP equipment do not reflect the true useful life of the equipment, then DOE should present such evidence to Treasury, which will consider it while conducting a Congressionally mandated review of depreciation methodologies due to be completed in March, 2000.

C. Electric Utility Company Mergers

Section 203 of the Federal Power Act requires that FERC review the sale or merger of jurisdictional facilities (e.g., transmission facilities and jurisdictional power sales contracts) and, before approving the transaction, must find that the transaction is consistent with the public interest. In performing its duties under this section, the Commission has reviewed the impact of mergers and acquisitions on the competitiveness of wholesale electric markets but generally has reviewed the effect on retail markets only where an affected state commission has no authority or insufficient resources to do so and has raised concerns about the effect of the merger on state regulation. In this bill, DOE recommended, and all parties agreed, that FERC should be required to review the impact of mergers and acquisitions on the competitiveness of retail markets, because merger between utilities located in one or more states can affect the competitiveness of retail electric markets in an entire region.

Unresolved Issue: Should FERC be required to consider the effect of a merger on retail competition during a merger proceeding between two cooperatives or municipal utilities with loans outstanding to the Rural Utilities Service?

Option #1: FERC should not examine the effects on retail competition of two cooperatives or municipal utilities with loans outstanding to the Rural Utilities Service.

Option #2: FERC should examine the effects on retail competition of all mergers, including those of two cooperatives or municipal utilities with loans outstanding to the Rural Utilities Service.

USDA/RUS Position: The Rural Utility Service already examines the effects of mergers between two parties to which have loans outstanding to RUS. Because RUS's mission is to provide low cost electricity to its constituency, it would not approve a merger that would have the effect of raising prices to retail customers. Review of such mergers by other federal agencies would be unnecessary and duplicative.

Treasury/CEA Position: RUS has no expertise in examining the anticompetitive effects of mergers. Such expertise is located at FERC, Justice, and the FTC. In fact, the RUS's process may examine the effect of mergers on the current customers of the merging utilities, but not on third parties that also may be affected by a merger in a competitive market. In this circumstance, the anticompetitive effects of mergers of RUS financed entities should be examined by FERC, as are all other mergers. Moreover, RUS's process is not a formal on-the-record administrative hearing, such as those held by FERC, in which any potentially affected party may come and identify a concern to be addressed by the review process. Such an examination should be conducted by those agencies that already possess the appropriate expertise.

D. Assistance to Indian Tribes

The Administration's bill encourages states to adopt retail competition to improve generation efficiency, lower electricity costs, and improve the environment. In drafting its bill, DOE was concerned that restructuring the electric industry will likely have a mixed impact on Indian tribes, and that some Indian tribes might not be able to fully realize these benefits. As part of its attempt to address the needs of Indian tribes, DOE included in its draft bill a grant program, through which DOE could provide tribes with assistance, in consultation with the Secretary of the Interior, in analyzing tribal electricity needs, the availability of natural resources for electricity generation, opportunities for transmission enhancement/construction, and effects of state restructuring programs on tribal electricity supplies. DOE's bill also authorized electricity infrastructure grants to Indian tribes.

In addition to including provisions in the bill to ensure that Indian tribes can obtain benefits from restructuring as consumers of electricity, DOE also wanted to enable tribes to participate as new entrants in competitive electricity markets. Accordingly, DOE proposed the inclusion in the bill of an investment tax credit for the builders of electricity generating plants and other facilities that are used for sales to non-tribal customers.

Unresolved Issue: Should the bill contain investment tax credits for the building of generation plants on Indian reservations?

Option #1 (DOE Proposal): Include tax credits in bill.

Option #2: Do not include tax credits in bill.

DOE Position: The electricity restructuring bill should include investment tax credits for the construction of new generation capacity on Indian reservations that will serve non-Indian areas. This provision will ensure that tribes can participate in the restructured electricity market.

Treasury/CEA Position: The tax code already contains numerous programs designed to assist Indian tribes, including accelerated depreciation of certain capital constructed on reservations, including power plants. The adoption of additional credits is, therefore, unnecessary. Moreover, the electricity restructuring bill is not the appropriate vehicle for the creation of economic development programs for Indian tribes.

E. Programs and Benefits for Displaced Workers

During a previous attempt by the Administration to draft an electricity restructuring bill, the labor unions told the Administration that they did not want the issue of displaced workers addressed at the federal level. In the interim, however, the unions have changed their minds, and have requested that the Administration provide generous guarantees and benefits for those workers that might lose their jobs as a result of electricity restructuring.

In response to union concerns, DOE's draft bill authorized the creation of a program for displaced workers, to be located at DOE. DOE hoped that through its program it would be able to retrain displaced workers to work in sectors of the electricity industry that would grow as a result of restructuring (e.g., solar generation, combined heat and power generation, distributed power). DOE felt that because of its experience in training workers for certain energy related industries, and because of its experience working with displaced workers from its nuclear weapons complex, it was well suited to manage such a program.

Unresolved Issue: In Which Agency Should Programs for Displaced Workers be Located?

Option #1 (DOE Proposal): Displaced worker program should be located at DOE.

Option #2: Displaced worker program should be located at the Department of Labor (DOL).

DOE Position: The displaced worker program should be located at DOE because of its desire to train workers in emerging segments of the electricity industry, and its experience in working with workers displaced from DOE's nuclear weapons complex.

OMB Position: Any displaced worker program should be located at DOL. DOL possesses the greatest level of expertise in designing and operating worker training program and in managing benefits for displaced workers. The bill could simply direct displaced workers to DOL to obtain generally available assistance for all displaced workers, it could earmark a portion of funds for displaced workers for those who were displaced by electricity restructuring, it could make displaced workers eligible for enhance benefits similar or equal to those available under the Trade Adjustment Assistance Act or it could create a new program just for those affected by this bill. Whichever option was chosen, it would be located in the agency with the greatest expertise in the subject area.

Placing such a program at DOL also is consistent with other Administration's policies. It is consistent with the Administration's program to create one-stop shopping for benefits and training for displaced workers and other unemployed individuals. It is also consistent with the Administration's desire not to create industry-specific programs, preferring instead to support one economy-wide program that provides an appropriate level of support and training for all displaced workers and other unemployed individuals. Creating such a program at DOE is poor policy because such a policy would fail to take advantage of the expertise available at DOL, and is inconsistent with other Administration priorities described above.

Summary of Unresolved Issues From Meeting Three
Issues Affecting the Indian Tribes, Efficient Generation and Remote Power,
Alaska, CHP/DP, Reliability of the Grid,
Consumer Protection and Worker Displacement

Tax Credits For Indian Tribes

Issue: Inclusion of Tax Credits for Construction of Power Related Projects on Indian Reservations

Unresolved Issue: Should the bill include tax credits for construction of power related projects on Indian reservations.

DOE Position: The bill should include a 10 percent tax credit for construction of power related jobs on reservations. Tribes would have to be partners in such projects.

Treasury/CEA/OMB Position: Both agencies were unclear as to the goal of the tax credits -- increased power availability or economic development. Treasury was opposed to the tax credits, noting that accelerated depreciation is already available for such projects on reservations. It did not know, however, the effect of the existing tax benefits (which have been in place for five years) on the construction of such projects.

EPA Position: This provision might tend to increase CO2 emissions and thereby increase the cost of compliance with international agreements on climate change. Given the availability of substantial coal resources on some Indian reservations, the lure of large tax credits might encourage the construction of otherwise uneconomic coal-fired plants, which have significantly higher CO2 emissions than other alternatives. Moreover, EPA does not see how this provision will bring electrification to unserved areas on Indian reservations.

DOI Position: A tax credit provision should be included in the bill for the construction of power related projects on Indian reservations.

Distributed Generation/Combined Heat and Power

Issue #1: Use of one depreciation rate for DG/CHP equipment.

Unresolved Issue: Adoption of seven year depreciation for qualified equipment.

DOE Position: Adopt a single seven year depreciation schedule for qualified equipment to reduce the tax obstacles against the use of such equipment.

Treasury Position: The depreciation rate should reflect the useful life of the asset; it should not be adjusted simply to provide an incentive to use such equipment. If there is a policy reason for promoting their use, it should be addressed by a narrowly focused tax credit. If DOE has information indicating that the depreciation schedule does not reflect the true useful life of the assets, Treasury is willing to examine the evidence and consider adjusting the depreciable life.

Issue #5 and #6: Grants to support Electrification of Remote Communities and Southeast Alaska Intertie

Unresolved Issue: Who should administer the grant programs.

DOE Position: DOE should administer the program.

CEA Position: We need a better demonstration that there is a need for a grant program.

USDA Position: USDA should administer the program because of its expertise in the field and history of working with remote communities. Further, if USDA ran the program it would be in a position to combine grants and loans to get power to remote communities cannot obtain loans.

Issue: Reliability

DOI Position: It is our understanding that the legislative language being drafted regarding the regulation of reliability will ensure that the existing authority of operators including the Bureau of Reclamation will not be preempted. We understand that we will have the opportunity to review the legislative language to confirm that existing authorities are not affected.

Bureau of Reclamation Issue: While we are active participants in planning and other activities of the WSCC, we remained concerned about giving this entity regulatory authority over Reclamation's generation. Because of our statutory and contractual framework, Reclamation cannot cede control of its facilities which might violate our authorized purposes.

Issues: Availability of Information

Unresolved Issue: Should DOE establish "electricity shopper" database.

OMB/OIRA: DOE should talk to EIA to determine the feasibility of collecting and maintaining such data in a manner that it would be useful and accurate.

Issue: Mergers

Unresolved Issue: FERC review of mergers of utilities that have loans outstanding at USDA.

DOE Position: All such mergers should be reviewed by FERC.

USDA Position: Such mergers should not be reviewed by FERC.

Issue: Worker Displacement

DOE Position: DOE retracted its proposal that the public benefits fund be accessible to fund programs that assist displaced workers.

Summary of Unresolved Issues From Meeting Two
Issues Affecting the PMAs, Indian Tribes, and Mergers

Bonneville Power Administration

Issue #1: Transmission Jurisdiction

Unresolved Issue: Whether sections 205 and 206 apply to the PMAs just as they apply to other utilities or whether FERC authority is potentially constricted by the PMAs authorities under other laws.

OMB Position: We need to address this issue.

DOI Position: If we subject BPA (and WAPA) to FERC's authority, it is essential that the caveat "but condition FERC's exercise of its authority so as to assure that BPA (and WAPA) meets its other recognized responsibilities" be retained. Those other recognized responsibilities include fish and wildlife mitigation funding, which is critical to, among other things, the recovery of listed salmon stocks for which various Indian tribes hold treaty rights. We suggest that any final language about the conditional authority be made very explicit (i.e., include a list of those other responsibilities, especially the fish and wildlife funding). We do not believe what BPA's "other recognized responsibilities" are should be left to possible interpretation in given cases.

Issue #2: Participation in an ISO

Unresolved Issue: Whether PMAs will be permitted to voluntarily turn over transmission lines to an ISO.

OMB Position: We need to address this issue.

Bureau of Reclamation Concern: While Reclamation recognizes the value of BPA participating in an ISO, it is concerned that this control be limited to transmission operations. The legislative proposal must ensure that control of the generation remain with Reclamation or the Corps of Engineers (depending upon the Project). Reclamation operates its powerplants as part of a multipurpose project pursuant to parameters embodied in the specific authorization language adopted by Congress to meet statutory and contractual obligations that may not maximize power generation. Reclamation must be allowed to control generation in order meet this legal requirement.

Issue #3: Recovery by BPA of Non-Recoverable Generation Costs

Unresolved Issue: How should BPA recover fish and wildlife and other costs that can't be recovered in generation rates.
DOE/BPA Position: Strengthen BPA's ability to recover with a surcharge on transmission otherwise non-recoverable power costs subject to FERC oversight. Total recovery would be limited to $400 million by 2016, with a $50 million annual cap.

NOAA Position: There should be no cap on the amount on non-recoverable costs. Otherwise, Treasury might have to fund the costs that are directly attributable to BPA generation.

DOI Position: BPA should be allowed to recover otherwise non-recoverable costs, such as fish and wildlife or other costs through a transmission surcharge mechanism. There should be no cap on the amount on non-recoverable costs. The Administrator should retain discretion to determine when and whether to invoke the transmission surcharge cost recovery mechanism. Decisions regarding an expiration date foe the transmission surcharge should account for BPA's ability to pay its WPPSS debt by that date.

Treasury/CEA Position: Why permit BPA to impose a surcharge on transmission, thereby shifting generation costs to the transmission customers?

OMB Position: BPA has a sufficient cushion that it should be able to pay all of its own non-recoverable costs by charging higher than cost and still remain at or below market rates.

Western Area Power Administration and Southwestern Power Administration
Bonneville Power Administration

Issue: Transmission Jurisdiction

Unresolved Issue: Whether sections 205 and 206 apply to the PMAs just as they apply to other utilities or whether FERC authority is potentially constricted by the PMAs authorities under other laws.

See discussion regarding BPA.

Issue: Recovery by WAPA and SWPA of Non-Recoverable Generation Costs

Unresolved Issue: How should WAPA and SWPA recover fish and wildlife and other costs that can't be recovered in generation rates.

DOE Position: None.

DOI Position: As with BPA, SWPA and WAPA should be allowed to recover otherwise non-recoverable costs pursuant to a surcharge on transmission. "Unrecoverable cost" should be clearly defined and should include such costs as irrigation assistance.

CEA Position: We should preclude the possibility of the PMAs imposing a surcharge on transmission, thereby shifting generation costs to the transmission customers, because such a surcharge is anticompetitive.

Issue: WAPA Participation in an ISO

Unresolved Issue: Whether PMAs will be permitted to voluntarily turn over transmission lines to an ISO.

Bureau of Reclamation Concern: As with the BPA issue above, we are concerned that control of the generating assets remain with Reclamation to ensure that the facilities are operated to meet the authorized purposes for which they were built and to ensure that we meet our contractual obligations.

Indian Tribe Assistance

Issue #1: Indian Tribe Assistance

Unresolved Issue: Who should oversee grants to Indian tribes.

DOE Position: DOE should administer grant program in consultation with the Secretary of the Interior.

DOI Position: DOE should administer grant program in consultation with the Secretary of Interior. The cost-share provision in the grant program should be removed to enable underfunded tribes to participate in and benefit from the program.

USDA Position: USDA/RUS should administer the grant program because of their expertise in managing similar programs. Moreover, the program should target unserved areas and take into account existing RUS financed generation that may have been originally constructed at a capacity to serve the area in question.

Consumer Protection

Issue #6: Utility Company Mergers

Unresolved Issue: Should FERC have power to review utility company mergers.

DOE Position: FERC should review mergers.

Treasury Position: Why does FERC need to review mergers if FTC and DOJ already have such authority.

Summary of Unresolved Issues From Meeting One
Issues Affecting the Tennessee Valley Authority

Issue #2: Wholesale Electric Energy Rate Regulation

Unresolved Issue: Whether FERC should oversee wholesale rates charged by TVA.

TVA Position: FERC should not oversee TVA's wholesale rates for three reasons: 1) FERC already has authority over TVA's transmission, stranded investment, and contract appeals. TVA's remaining power is its market power, and that will be constrained by the anti-trust laws; 2) TVA is mandated by statute to set rates, at the direction of Presidential appointees. There is no need for one set of appointees (FERC) to carry out a duplicative statutory consumer protection mission already performed by another set of appointees (TVA); and, 3) TVA's role is to provide low cost power to the Tennessee Valley. It has no motive to earn a profit. Therefore, the purpose of FERC oversight is unclear, as TVA would have no incentive to set high prices. FERC oversight will, however, concern the financial markets, and perhaps raise the cost of debt for TVA. Such debt has been inexpensive in the past because of TVA's ability to set rates in such a manner that guaranteed that it could recover its costs.

DOE Position: TVA should be overseen by FERC to ensure just and reasonable rates, guard against market power abuses and to prevent cross-subsidization by those inside the fence of sales to those outside the fence. TVA's second concern, about the independence of Presidential appointees, is unwarranted, as they have already agreed to subject themselves to oversight by FERC in numerous other areas. Further, FERC is directed to consider TVA's ability to repay its debt in setting its rates. The bond markets appear more concerned about other factors than who sets TVA's rates. Finally, if FERC determines that TVA has no market power, FERC would not regulate TVA's wholesale rates.

Issue #4: Retail Regulation of Electric Energy Sales

Unresolved Issue #1: The response to customers' efforts to bypass their current distributor through the duplication of facilities.

DOE Position: The ability to bypass a local distribution utility is the subject of state law. As all states other than Tennessee already have a body of utility law (and Tennessee is expected to develop one), this is an issue that should be left to the states. Further, this issue is the same issue that confronts every other utility, so its treatment should be no different for the distributors in the TVA region than for other utilities.

TVA Position: TVA believes that although the issue is the same that confronts all other utilities, that because TVA was the regulator of the distribution utility, the Federal government has a responsibility to address the stranded costs associated with bypass. In other instances where the states are expected to address the issue, they (and not the Federal government) were also the regulator that presumably approved the expenditure (implicitly in a rate case or otherwise) that paid for subsequently stranded investments.

Unresolved Issue #2: Retail Sales of TVA power within the fence.

TVA Position: TVA should be permitted to sell retail power within the fence once it has obtained the consent of the distribution utility in the area that it wants to sell electricity, or if the distribution utility obtains less than half of its power from TVA.

DOE Position: TVA should be permitted to sell retail power within the fence once it has obtained the consent of the distribution utility in the area that it wants to sell electricity. DOE objects to the 50% threshold in the TVA proposal because that could be used to "force" distributors to buy wholesale power from TVA (to increase their purchases above the 50% threshold) in an effort to keep TVA from competing in their market at the retail level.

Issue #5: The TVA Fence

Unresolved Issue #1: TVA will not sell power at the retail level outside its fence.

Treasury Position: This is anticompetitive. Why should distributors capture the economic rents on sales instead of letting TVA compete and offer lower retail rates.

TVA Position: This is part of a regional compromise to allay the concerns of those who would be competing with TVA. TVA's competitors believe that because of TVA's (perceived) Federal subsidy it would be unfair for them to have to compete at the retail level.

Unresolved Issue #2: What is the effect of competition on TVA's financial health.

TVA Position: Having reviewed the restructuring plan and its business plan, TVA feels confident that its financial health will remain strong in the new competitive environment.

OMB/Treasury Position: Would like to see more detail about the effect of restructuring on TVA and to understand more clearly the analysis that led TVA to conclude that it will remain financially secure and succeed in the new environment.

Issue #7: Stranded Cost Recovery

Unresolved Issue #1: Should all stranded costs have to recovered by October 1, 2007.

TVA Position: The 2007 date is a workable date. All stranded cost recovery plans have to be structured over a specified period of time and this one is workable. If the statute did not have a date certain, FERC would merely have to pick one. This reassures those who will we affected by stranded costs that there will be a deadline after which they will face no additional charges.

OMB Position: TVA needs to demonstrate further that the date is one that will not harm TVA's financial position, or that of the treasury.

Unresolved Issue #2: How to address bypass. See issue #4 above.

Unresolved Issue #3: TVA's use of stranded cost receipts.

DOE Position: TVA should use the receipts to pay down its debt because the primary purpose for authorizing stranded cost recovery is debt repayment. Use of stranded cost receipts to pay for new generation could provide TVA an unfair competitive advantage. TVA agreed to use stranded cost receipts for debt repayment in the TVA Advisory Committee process.

TVA/Treasury Position: Stranded cost recovery should be used primarily to repay its debt. However, TVA's Board must retain the flexibility to manage TVA's finances from year to year. Therefore, there should not be a dollar-for-dollar requirement to repay the debt with stranded investment recovery but rather a statement of policy and intent to do so.

Issue #8: Market Power

Unresolved Issue: Should TVA be subject to market power provisions of the bill.

TVA Position: No FERC oversight is necessary, as TVA has no market power, and TVA's power will be constrained by the anti-trust laws.

DOE Position: This only matters if TVA develops market power. If it has none, then the provision is irrelevant. If it develops market power, then the oversight will be useful. If TVA is correct in that it will not have power, then FERC will take no action. Accordingly, there is no reason for TVA to object to this provision.

<u>Previously Unaddressed Issue</u>

<u>Issue: Whether a "level playing field" exists for competition between IOUs and TVA.</u>

<u>*CEA Concerns*: The Administration is seeking to promote competition in sales of electric power at wholesale and retail levels. Do public agencies, such as TVA, face the same or similar rules as IOUs? To what extent is it desirable for all participants to compete under identical or similar rules? What measures should be adopted to ensure reasonably "fair" competition?</u>

List of Unresolved Issues Regarding DOE's Memo on Electricity Restructuring

Issue #2: Wholesale Electric Energy Rate Regulation

Unresolved Issue: Whether FERC should oversee wholesale rates charged by TVA.
Agencies: NEC, DOE, TVA, OMB, FERC, Treasury, OVP, CEA

Issue #4: Retail Regulation of Electric Energy Sales

Unresolved Issue #1: The response to customers' efforts to bypass their current distributor through the duplication of facilities.
Agencies: NEC, DOE, TVA, OMB, FERC, OVP

Unresolved Issue #2: Retail Sales of TVA power within the fence.
Agencies: NEC, DOE, TVA, OMB, FERC, OVP

Issue #5: The TVA Fence

Unresolved Issue #1: TVA will not sell power at the retail level outside its fence.
Agencies: NEC, DOE, TVA, OMB, FERC, Treasury, OVP, CEA

Unresolved Issue #2: What is the effect of competition on TVA's financial health.
Agencies: NEC, DOE, TVA, OMB, FERC, Treasury, OVP

Issue #7: Stranded Cost Recovery

Unresolved Issue #1: Should all stranded costs have to recovered by October 1, 2007.
Agencies: NEC, DOE, TVA, FERC, OMB, OVP

Unresolved Issue #2: How to address bypass. See issue #4 above.
Agencies: NEC, DOE, TVA, FERC, OMB, OVP

Unresolved Issue #3: TVA's use of stranded cost receipts.
Agencies: NEC, DOE, TVA, OMB, FERC, Treasury, OVP

Issue #8: Market Power

Unresolved Issue: Should TVA be subject to market power provisions of the bill.
Agencies: NEC, DOE, TVA, FERC, OMB, OVP, CEA

New Issue: Level Playing Field

Unresolved Issue: Whether a "level playing field" exists for competition between IOUs and TVA.
Agencies: NEC, DOE, TVA, FERC, OMB, OVP, CEA

Bonneville Power Administration

Issue #1: Transmission Jurisdiction

Unresolved Issue: Whether sections 205 and 206 apply to the PMAs just as they apply to other utilities or whether FERC authority is potentially constricted by the PMAs authorities under other laws.

Agencies: NEC, DOE, BPA, OMB, Bureau of Reclamation, FERC, CEA

Issue #2: Participation in an ISO

Unresolved Issue: Whether PMAs will be permitted to voluntarily turn over transmission lines to an ISO.

Agencies: NEC, DOE, OMB, DOI/Bureau of Reclamation, BPA, PMAs, CEA

Issue #3: Recovery by BPA of Non-Recoverable Generation Costs

Unresolved Issue: How should BPA recover fish and wildlife and other costs that can't be recovered in generation rates.

Agencies: NEC, DOE, OMB, BPA, NOAA, DOI, Treasury, CEA, CEQ, FERC, DOJ/Environment, OVP

Western Area Power Administration and Southwestern Power Administration

Unresolved Issue: Whether sections 205 and 206 apply to the PMAs just as they apply to other utilities or whether FERC authority is potentially constricted by the PMAs authorities under other laws.

Agencies: NEC, DOE, BPA, OMB, Bureau of Reclamation, FERC, CEA, PMAs.

Unresolved Issue: How should WAPA and SWPA recover fish and wildlife and other costs that can't be recovered in generation rates.

Agencies: NEC, DOE, OMB, DOI, PMAs, Treasury, CEA

Unresolved Issue: Whether PMAs will be permitted to voluntarily turn over transmission lines to an ISO.

Agencies: NEC, DOE, OMB, DOI/Bureau of Reclamation, BPA, PMAs, CEA

Indian Tribe Assistance

Unresolved Issue: Who should oversee grants to Indian tribes.

Agencies: NEC, DOE, DOI, USDA, DOJ/Environment

Tax Credits For Indian Tribes

Unresolved Issue: Should the bill include tax credits for construction of power related projects on Indian reservations.

Agencies: NEC, DOE, OMB, Treasury, DOI, EPA

Distributed Generation/Combined Heat and Power

Unresolved Issue: Adoption of seven-year depreciation for qualified equipment.

Agencies: NEC, DOE, Treasury

Unresolved Issue: Who should administer the grant program.

Agencies: NEC, DOE, USDA, EPA

Issue: Reliability

Unresolved Issue: Whether the legislative language regarding the regulation of reliability will ensure that the existing authority of operators including the Bureau of Reclamation will not be preempted.

Agencies: NEC, DOE, DOI

Issues: Availability of Information

Unresolved Issue: Should DOE establish "electricity shopper" database.

Agencies: NEC, DOE, OMB/OIRA

Issue: Mergers

Unresolved Issue: FERC review of mergers of utilities that have loans outstanding at USDA.

Agencies: NEC, DOE, USDA, FERC

File-
Electricity
Restructuring

Todd Stem 01/08/99 10:07:29

Record Type: Record

To: Elizabeth A. Arner/WHCCTF/EOP

cc:
Subject: Electricity Restructuring

Could you print this out? It looks hugely long. Or else get a copy from NEC. Thanks. tds

--------------------- Forwarded by Todd Stern/WHO/EOP on 01/08/99 10:08 AM ---------------------------

Ronald Minsk
01/06/99 02:56:59 PM

Record Type: Record

To: See the distribution list at the bottom of this message

cc: Brian A. Barreto/OPD/EOP
Subject: Electricity Restructuring

ELECREST.WPI

In the near future, the Administration plans to submit an electricity restructuring bill to Congress. The bill will be identical to the bill that we sent to Congress last summer in most respects. The Department of Energy has, however, made a limited number of changes to address issues that were not addressed by the previous bill.

DOE has prepared a summary of the changes to the previous bill, and has sent the memo to OMB and the NEC. The NEC is coordinating an interagency review of the memo, which is attached to this e-mail in Word Perfect 6.0 format. The NEC welcomes your participation, or that of the appropriate representative of your Department, in the interagency review process. Once that process is concluded, OMB will distribute a legislative referral memorandum with the legislative language so that agencies may confirm that their understanding of the policies outlined in the memo are reflected in the bill.

Because the bill that was sent to Congress last summer went through a similar interagency review, the current review will only address those issues that have changed since last summer. The NEC does not plan to once again address those issues that were resolved in the interagency review that concluded last summer.

The NEC has scheduled (or plans to schedule) a series of meetings to address various components of the bill. Although each agency is welcome to attend any and all meetings, you may choose to limit your attendance to meetings that will address issues of interest to your agency.

Below is a draft agenda for three planned meetings, and a list of agencies that we feel will have an interest in the topics on the agenda.

Meeting #1: Wednesday, January 13th, 2:00 pm, Old Executive Office Building, Room 239

1) Issues related to the Tennessee Valley Authority

Agencies: DOE, TVA, Treasury, FERC

Meeting #2: Thursday, January 14th, 10:00 am, Old Executive Office Building, Room 239

1) Issues related to the Bonneville Power Administration, the Western Area Power Administration, and the Southwestern Power Administration
2) Indian Tribe Assistance
3) Reliability of the grid
4) Utility company mergers

Agencies: DOE, Treasury, Interior, FERC

Meeting #3: To be scheduled

1) Efficient Generation Technologies and Remote Power
2) Consumer Protection
3) Electric systems in communities in Southeast Alaska
4) Worker displacement

Agencies: DOE, Treasury, EPA, FERC, HHS, Labor, Agriculture

Meeting #4: To be scheduled

1) Miscellaneous items not identified above

Once again, please note that although we have identified the agencies that we believe are most likely to have an interest in attending each meeting, any agency is welcome to attend any meeting.

In order to attend any meeting, please e-mail me, Ron Minsk, at "ronald_minsk@opd.eop.gov" with the name, birthday, and SSN of each attendee. If you have any questions about the review process, please feel free to e-mail me or call me at 456-2809.

Thanks in advance for your interest and participation.

Ron Minsk

Message Sent To: ______________________________

Ronald Minsk/OPD/EOP
Sally Katzen/OPD/EOP
Todd Stern/WHO/EOP
Elwood Holstein/OMB/EOP
Gary L. Bennethum/OMB/EOP
Lori A. Krauss/OMB/EOP
Richard A. Mertens/OMB/EOP
James Mietus/OMB/EOP
Erik K. Godwin/OMB/EOP
E. Holly Fitter/OMB/EOP
Roger S. Ballentine/WHO/EOP
Todd Stern/WHO/EOP
George T. Frampton/CEQ/EOP
Linda Lance/CEQ/EOP
richard.glick @ hq.doe.gov @ inet
c.whillock @ usda.gov @ inet
perciasepe.robert @ epa.gov @ inet
Gardiner.david @ epa.gov @ inet
jmpablo @ tva.gov @ inet
douglas.smith @ ferc.fed.us @ inet
samuel-william @ dol.gov @ inet
anne_shields @ ios.doi.gov @ inet
Alan S. Polasky/CEA/EOP

THE DEPARTMENT OF ENERGY'S PROPOSED MODIFICATIONS TO THE "COMPREHENSIVE ELECTRICITY COMPETITION PLAN"

December 28, 1998

Background

On May 13, 1997, the Department of Energy forwarded to relevant agencies recommendations to help effectuate an efficient transition towards a restructured competitive electric utility industry. After a lengthy series of interagency meetings, the agencies reached consensus on a set of proposals that eventually became the Clinton Administration's "Comprehensive Electricity Competition Plan".

The Administration Plan, which was announced on March 25, 1998, would (1) encourage the implementation of competition among retail electric suppliers; (2) provide the states and unregulated utilities the appropriate flexibility and authority to determine whether and how to proceed with competition; (3) promote reliable, competitive and efficient electricity markets; (4) allow all consumers to benefit from a competitive market; and (5) protect the environment and support energy conservation and renewable resources. The Administration converted the Plan into legislative language and transmitted its bill, the Comprehensive Electricity Competition Act, to Congress on June 26, 1998. On July 10, Senators Murkowski and Bumpers introduced the bill, by request, in the Senate. The Administration bill was not introduced in the House of Representatives before the 105th Congress adjourned.

A number of electric restructuring bills were introduced in the House and the Senate during the 105th Congress. These bills ranged from, on the one end, mandating retail electric competition throughout the United States by a date certain to, at the other end of the spectrum, simply repealing certain federal statutes that could inhibit competition in states that choose to proceed. The House Commerce Committee held a series of hearings and the Senate Energy and Natural Resources Committee conducted several workshops on electric restructuring. However, neither committee took any action.

Although the 105th Congress did not act on electric restructuring legislation, the issue is expected to receive considerable attention in the 106th Congress. Both Senate Energy and Natural Resources Committee Chairman Murkowski and House Commerce Committee Chairman Bliley have made passage of a restructuring bill a high priority for 1999. In addition, federal legislation has gained momentum because 18 states have now passed legislation or issued regulations that provide for retail electric competition and almost every other state has the matter under active consideration. There is a growing consensus that, at the very least, the federal government needs to act to eliminate the barriers preventing the states from proceeding with their competition programs and to protect the reliability of the interstate electricity grid.

The Administration's Comprehensive Electricity Competition Plan and legislation includes most of the provisions necessary to achieve the Administration's goals with regard to the restructuring of the electric utility industry. However, several issues were not adequately developed for inclusion in the Plan, and additional issues were raised subsequent to its release. As a result, Secretary Richardson directed DOE to augment the Plan to address these issues and make several other additions consistent with the Administration's goals.

This memorandum discusses these issues and makes recommendations regarding modifications to the Administration's proposed legislation. Except for minor clarifications related to the intent of existing language, DOE does not propose making changes to those subjects that were already considered in the previous interagency review process. The recommendations discussed below center around the following:

- creating an atmosphere that improves the prospects for competition in the regions served by the Tennessee Valley Authority, the Bonneville Power Administration and the other federal power marketing administrations;
- encouraging the use of environmentally friendly technologies, especially in areas not connected to the interstate electric grid;
- protecting consumers;
- enhancing the reliability of our electric systems; and
- a set of miscellaneous items designed to increase the benefits associated with competitive markets.

We hope to forward the legislative language associated with these recommended modifications as well as clarifying technical changes to the Administration's original bill shortly and that the interagency review process be commenced early in January so that the Administration can send its revised bill to Capitol Hill as soon as possible..

I. FEDERAL POWER SYSTEMS

The Comprehensive Electricity Competition Plan was completed before the Administration was prepared to make recommendations concerning the introduction of competition in the Tennessee Valley Authority service area and the appropriate regulatory treatment of the federal power marketing administrations. This section of the memorandum addresses the appropriate role for the Tennessee Valley Authority in future competitive markets and the regulatory changes necessary to ensure that federal ownership of transmission facilities does not impede competition.

A. THE TENNESSEE VALLEY AUTHORITY

The Tennessee Valley Authority ("TVA" or "the Authority") is a government owned corporation created by the TVA Act of 1933 with a warrant to provide electric power, flood control, navigational control, agricultural and industrial development and other services to a region including all of Tennessee and parts of six surrounding states. Originally, the non-power components of TVA's mission were of greater importance than the power program. Dams were built primarily for flood control and navigation, with power production as a lower priority. As time went on, however, power production became increasingly prominent.

As electricity demand increased in the region in the 1940's, TVA began building coal-fired generating plants. In the 1960's, TVA initiated a major nuclear power construction program. TVA's generation mix is currently approximately 54 percent coal, 20 percent nuclear, 17 percent hydro, and 9 percent gas. TVA is required under the TVA Act to give preference in the sale of power to states, counties, municipalities and cooperatives.

In 1959, Congress amended the TVA Act to require TVA to fund power programs out of electricity revenues entirely. In addition, the 1959 Amendments created the so-called "TVA fence" by limiting TVA to sales of electricity to its own wholesale requirements customers and industrial retail customers inside its service territory and to economy exchanges with the fourteen surrounding utilities with whom it already did business. Other utilities are prevented from selling power inside the fence pursuant to contractual arrangements between TVA and the distribution utilities in the region. The 1959 amendments also authorized TVA to borrow money from private sources to finance the power program under a congressionally set debt cap. The cap has been raised a number of times over the years and now is $30 billion. TVA's outstanding debt is currently approximately $27 billion.

TVA is governed by a three member board of directors, appointed by the President and confirmed by the Senate to nine-year terms. The board is accountable to the President and to Congress for annual appropriations for the non-power programs. The board manages TVA, both as to power and non-power programs and is not subject to oversight of its planning and rates for power. TVA is not subject to either federal or state regulatory commission jurisdiction, except to the limited extent that the Authority is subject to FERC regulation pursuant to sections 211 and 212 of the Federal Power Act for transmission through the TVA service territory but not to the

Authority's existing customers. In addition, TVA is exempt from antitrust laws.

TVA supplies power to 159 retail distributors in its service territory. The distributors are all either municipal or cooperative utilities that purchase power pursuant to full requirements contracts that do not allow the distributors to acquire power from sources other than TVA. They also give TVA the right to set retail rates. Until recently, the contracts were essentially evergreen with ten year notice provisions for termination. Some distributors have entered into contracts that shorten these notice provisions. TVA also sells, in retail, directly to 67 large industrial and federal customers.

In November, 1997, the Tennessee Valley Electric System Advisory Committee was created under the authority of the Secretary of Energy Advisory Board (SEAB), and chaired by former Congressman Butler Derrick, to consider the appropriate role for TVA in competitive markets. The Committee, which was comprised of a broad spectrum of TVA stakeholders, sent its report to the SEAB. The SEAB approved the report on March 31, 1998, and, thereafter, transmitted it to the Secretary of Energy.

After careful review of the Advisory Committee report, DOE recommends the inclusion of language in the Administration's bill to bring the TVA region into the competitive framework envisioned in the proposed legislation. This section presents options and recommendations for a TVA title to be included in the Administration's Comprehensive Electricity Competition Act. The recommendations are consistent with those recommendations contained in the Advisory Committee report, where consensus was reached.

Issue 1. TRANSMISSION RATE JURISDICTION – Should TVA be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act for determining transmission rates, terms and conditions?

Recommendation: Subject TVA transmission to FERC jurisdiction under sections 205 and 206 of the Federal Power Act, but condition FERC's exercise of its authority so as to assure that TVA can recover its costs and that it meets its other recognized responsibilities, as appropriate. Open access requirements for power wheeled through the TVA service territory shall go into effect upon enactment of this Act; open

access requirements for power wheeled into the TVA service territory shall go into effect January 1, 2003.

TVA, along with all other currently non-Federal Power Act jurisdictional transmitting utilities (municipal, cooperative, state and federal utilities), should be subject to the same jurisdiction for transmission of electricity that applies to investor-owned utilities. Currently, the Commission has jurisdiction only over the rates, terms and conditions of transmission services of public utilities. The Administration explained in the Competition Plan that it is critical to the development and proper functioning of competitive markets that FERC be given jurisdiction over the transmission facilities of all utilities.

The Administration's bill, as presently drafted, subjects all transmitting utilities, including TVA, to the full transmission jurisdiction of the Federal Energy Regulatory Commission (FERC). Accordingly, there is no need to modify the Administration bill. This recommendation was supported by all members of the Advisory Committee.

Issue 2. WHOLESALE ELECTRIC ENERGY RATE JURISDICTION - Should TVA be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act for determining wholesale rates for electric energy?

Recommendation: Subject TVA wholesale electric energy rates, terms and conditions to FERC authority under sections 205 and 206 of the Federal Power Act, with the proviso that TVA's obligation to recover costs and repay outstanding debt will be taken into account, and that the existing preference for sales to public power entities contained in the TVA Act be retained.

Options: (1) Allow jurisdiction for rates to remain with TVA, but require that they be "just and reasonable and not unduly discriminatory" (with the proviso listed above), and provide for court review of rates under the new standard; (2) The status quo with TVA as final arbiter of rates under the TVA Act standard; or (3) Partial subjection to FERC jurisdiction for sales outside the TVA service territory.

TVA is not subject to FERC's wholesale electric energy rate jurisdiction under sections 205 and 206 of the Federal Power Act. TVA's rates instead are set by the TVA Board of

Directors pursuant to the TVA Act. That Act provides that:

> " rates...will produce gross revenues sufficient to provide funds for operation, maintenance, and administration of its power system; payments to States and counties in lieu of taxes; debt service on outstanding bonds...; payments to the Treasury as a return on the appropriation investment...; and such additional margin as the Board may consider desirable for investment in power system assets, retirement of outstanding bonds in advance of maturity, additional appropriation investment, and other purposes connected with the Corporation's power business having due regard for the primary objectives of the Act, including the objective that power shall be sold at rates as low as are feasible."

Sections 205 and 206 of the Federal Power Act require that rates and charges be just, reasonable, and not unduly discriminatory or preferential.

Subjecting TVA to the Federal Power Act rate standard would protect the developing competitive markets, both in the TVA region and in surrounding areas, from sales by an entity with potential market power but no available controls on that market power. Under the Federal Power Act, the Commission will only permit a company to sell power at market-based rates if that company lacks the ability to manipulate prices. Maintaining TVA as the arbiter of its own rates would constrain the development of a competitive market because TVA is not charged with protecting the competitiveness of the market.

Subjecting TVA to sections 205 and 206 of the Federal Power Act would also protect TVA's existing customers from the possible cross-subsidization of TVA's sales outside the fence. Existing customers could be required to continue to pay premium rates (to the extent competition in the TVA region is slow to develop) while cheaper power is sold into the competitive market. While states are able to prevent such cross-subsidies for investor-owned utilities, there is no comparable recourse for TVA's customers.

Conditioning application of the Federal Power Act standard on assuring recovery of TVA costs, as appropriate, and consistency with the preference requirements recognizes the continuing importance of TVA's mission and the need to assure the payment of TVA's debt. Accordingly, application of FERC's section 205 and 206 authority should be conditioned as suggested above.

The participants on the Advisory Committee were unable to reach consensus on this issue. A number of participants recommended application of FERC jurisdiction, but TVA objected. Among the arguments raised was that such new oversight would constitute an undue burden on TVA. Concerns that subjecting TVA to new regulatory requirements would constitute an onerous burden should be eased by the understanding that FERC could allow TVA to sell power at market-based rates if it did not have market power in the relevant markets, which is far less onerous than the old, cost-based rate regime. Further, FERC regulation is no more onerous for TVA than it is for the investor-owned utilities (that TVA will be competing with) who have been subject to it's rate regulation since 1935. DOE's Recommendation meets all of the Administration's principles for legislation: (1) it integrates TVA into the competitive market on an equal footing with other participants in the market; (2) it enhances the competitiveness of the market; (3) it protects consumers; and (4) it guards against the potential that TVA would not be able to pay off its debt.1

Issue 3. **ANTITRUST LAW – Should TVA be subject to the antitrust laws?**
Recommendation: TVA should be subject to the requirements and behavioral restrictions of antitrust laws with injunctive relief in court, but without the imposition of damages, treble damages or attorneys fees.

Option: TVA should be fully subject to antitrust laws and subject to all penalties and relief available under those laws.

TVA is currently exempt from applicability of the antitrust laws. All members of the Advisory Committee agreed that TVA should be subject to antitrust law, with differences as to applicability of penalties, as outlined in the Recommendation and Option.

Subjecting TVA to antitrust requirements with injunctive relief would allow courts to require the Authority to cease unfair trade practices and anti-competitive behavior. Some have argued that without penalties there would be no incentive for TVA to comply with the law. However, since TVA has no shareholders to bear the burden, such penalties would be paid by customers. This would have the perverse effect of making the buyers (TVA's customers) pay for the behavior of the seller (TVA) and would not create a greater incentive to avoid such behavior.

TVA had recommended that it be made subject to the Local Government Antitrust Act. Under the Local Government Antitrust Act (LGAA), 15 U.S.C. 34-36, local governments are immune from monetary damages in an antitrust case. 15 U.S.C. 36. However, the LGAA does not extend its immunity to injunctive relief. Cohn v. Bond, 953 F.2d 154-158 (4th Cir. 1991). Application of both the antitrust laws and the LGAA would have the effect of applying the antitrust laws for injunctive relief only. DOE agrees with TVA and accordingly recommends that the antitrust laws apply to TVA, but that such laws apply for injunctive relief only.

Issue 4. RETAIL REGULATION OF ELECTRIC ENERGY SALES - Should TVA continue to regulate the rates for sales of electric energy by TVA's wholesale customers to end users?

Recommendation: Provide that TVA does not have authority to act as regulator of the retail rates for electric energy sold by TVA's wholesale customers to end users. Allow states in the TVA region to determine whether they will regulate retail electricity sales in the TVA region.

Option: Preempt states to assure local (municipal or cooperative) control of retail electricity sales. Provide that no person shall duplicate facilities of the existing distributor for bypass.

TVA currently regulates the retail rates of its distribution utility customers. All members of the Advisory Committee agreed that TVA should not maintain that role. There were differences, however, as to who should serve that function.

All of TVA's existing wholesale customers are municipal or cooperative utilities who serve as retail distributors in the region. In other parts of the nation, states have the right, having authorized creation of these retail entities and serving as regulators of retail electricity sales, to regulate such distributors. Many do not do so, since these entities are not for profit and have no incentive to overcharge their customers. None of the states in the TVA region that regulate the retail sales of investor-owned utilities outside the TVA service territory regulate the sales of their municipal or cooperative distribution utilities. There is no reason to believe that states located within the TVA service territory would elect to regulate municipal and cooperative utilities within that territory once the fence is removed.

TVA's distributors have expressed interest in preempting states from regulating such entities in the future. First, we do not believe that there is cause for concern. Moreover, while we agree that local control is an important feature of municipal and cooperative utilities, preempting states would be inconsistent with the philosophy of the Administration's bill to encourage and enable, but not require, states to implement retail competition.

Issue 5. THE TVA FENCE

(a). TVA SALES INSIDE AND OUTSIDE THE FENCE – Should TVA be permitted to sell power inside and outside the TVA fence once the fence is removed?

Recommendation: Remove the statutory bar on sales outside TVA's existing territory, effective January 1, 2003. TVA should be allowed to sell power at wholesale, but not retail, outside its existing territory. TVA should be allowed to sell at retail to customers inside its existing territory only if the distribution utility in whose territory the retail customer lies has implemented retail competition and has agreed to the sale. Existing retail customers should have the right to continue as customers of TVA.

Option: Allow TVA to serve a new customer which could have been a retail customer of TVA absent removal of the fence.

TVA is prevented by law from selling outside its territory as defined in the TVA Act except to utilities with whom it had exchange power arrangements on July 1, 1957. If other suppliers are to compete inside TVA's service territory, TVA must be allowed to sell outside its existing territory or face a shrinking customer base, which would prevent TVA from recovering its costs and repaying its debt.

TVA is, at present, primarily a wholesale utility, with 85% of its load sold at wholesale to distributors in the TVA region and the other 15% sold to large industrial customers in the region. Concerns were raised in the Advisory Committee that TVA would have an unfair advantage as a competitor in retail markets. DOE recommends against allowing TVA to make retail sales outside the fence.

TVA's existing customers have proposed that TVA should only be able to sell at retail to new customers inside its existing service territory under conditions that are agreed to by the retail distributor in whose service territory any potential new customers might lie. Accordingly, DOE recommends that TVA be so constrained in its ability to sell to new retail customers.

(b). ANTI-CHERRY PICKING PROVISIONS -- Once the TVA fence is removed, should other utilities be able to sell power within TVA's traditional service territory?

Recommendation: Permit other utilities to sell power in the TVA region, effective January 1, 2003.

TVA is exempt from the authority of FERC to order transmission service under sections 210, 211 and 212 of the Federal Power Act if the transmission service is to existing customers of TVA. These provisions, known as the "anti-cherry picking" provisions, were enacted as part of the Energy Policy Act of 1992 and were intended to protect TVA from a circumstance where others could compete inside its service territory but TVA could not compete outside. Since we recommend the repeal of the prohibition on TVA sales outside its territory, that protection is no longer necessary. Moreover, without repeal of these provisions, there would be no prospects for competition in the entire TVA region because the distributing utilities and consumers in the region would have no alternatives but to continue purchasing power from TVA. Accordingly, we recommend that other entities be permitted to sell power at both wholesale and retail (assuming the implementation of retail competition) in the TVA region after January 1, 2003.

Issue 6. WHOLESALE POWER CONTRACTS – Should TVA be required to renegotiate its existing full-requirements contracts?

Recommendation: Require TVA to renegotiate existing full-requirements contracts with its distributors within one year of enactment in order

to allow for shorter contract terms, purchase of power from sources other than TVA after January 1, 2003, stranded cost recovery, and to provide that customers are not liable for the costs of new plants other than those specified in contracts. If TVA and its customers cannot reach agreement on the terms of a new contract within one year, parties should be required to submit the dispute to FERC for resolution.

TVA's wholesale power contracts with its distribution utility customers are ten-year, full-requirements contracts that do not allow distribution utilities to acquire power or resources from other providers. The contracts contain ten-year notice of termination provisions that are self-renewing and also give TVA the right to regulate the retail rates of its distribution customers. In order for TVA's customers to be able to participate in a competitive market, these contracts must be revised. The Advisory Committee agreed to a statutorily imposed renegotiation of the contracts for the purposes described in the Recommendation.

Issue 7. STRANDED COST RECOVERY – What mechanism should be put in place to provide TVA the opportunity to recover its stranded costs?

Recommendation: Authorize FERC to adjudicate recovery of stranded costs from departing customers. Such costs should be borne by those TVA customers for whom the costs were incurred. FERC should review and approve costs for which recovery is sought after receiving input from state authorities, when appropriate. The time period for recovery should not extend beyond October 1, 2007, unless otherwise agreed to by the parties. Stranded cost revenues should be used to pay down TVA's debt. TVA should be required to recover stranded costs from all customers for whom TVA had a reasonable expectation of continued service. Recovery should be through a non-bypassable mechanism that does not discriminate against any class of customers present or future. TVA should be required to use its best efforts to mitigate stranded costs.

The Administration's Plan contains a preference for stranded cost recovery. Accordingly, TVA and its distributors should also be provided the opportunity to recover their stranded costs.

Since no state would have jurisdiction over TVA, there must be a federal arbiter to provide for the Authority's recovery of its stranded costs. The framework for wholesale stranded cost recovery contained in FERC Order No. 888 may work well for this purpose. This Recommendation does not mandate that system, but would allow FERC to implement it or another system that meets the criteria outlined here. All participants in the Advisory Committee discussions agreed to the stranded cost recovery solution outlined above.

Issue 8. MARKET POWER – Should TVA be subjected to the market power provision proposed in the Administration's bill?

Recommendation: Subject TVA to FERC authority to require remedial measures to mitigate market power, effective January 1, 2003.

TVA is the largest generator of electricity in the country. Without giving FERC authority to require TVA to mitigate its market power, FERC's capacity to protect the competitiveness of the market would be substantially reduced.

The Administration bill proposes that utilities be given a great deal of flexibility to remediate market power, since it authorizes FERC to require utilities to submit a plan to mitigate market power where it is found. This process would allow TVA to craft a plan that would enable it to make debt payments while, at the same time, allowing FERC to remedy general or locational market power as it finds it, either through imposition of limitations on rates, protective mechanisms in contracts, or other mitigation measures that TVA can design. TVA should be made subject to FERC's authority in the bill to impose appropriate remedial measures to control market power.

Issue 9. PARTICIPATION IN AN INDEPENDENT SYSTEM OPERATOR -- Should TVA be permitted to join an ISO on a voluntary basis?

Recommendation: Authorize TVA to turn over operational control of transmission facilities to an independent system operator.

The Administration bill gives FERC the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator (ISO) to facilitate competition. An ISO would allow for the independent operation and control of transmission facilities separate from a utility's marketing functions. TVA is included within the definition of transmitting utilities, and it is the intent of the bill to ensure that FERC has the authority to require all transmitting utilities to participate in ISOs. To avoid any question of TVA's legal authority to participate in ISOs, we recommend that a provision be added to the bill to clarify that TVA may voluntarily participate in an ISO.

B. THE BONNEVILLE POWER ADMINISTRATION

The Bonneville Power Administration ("BPA" or "Bonneville") is a Federal agency that markets wholesale electrical power and operates and markets transmission services in the Pacific Northwest. The power comes from 29 Federal dams, one non-Federal nuclear plant, and various renewable resources. Bonneville serves a 300,000 square mile area including Oregon, Washington, Idaho, Western Montana, and parts of Northern California, Nevada, Utah and Wyoming. BPA is obligated to acquire power and conservation resources sufficient to meet the requirements of its customer utilities. About 40 percent of all the power consumed in the Pacific Northwest is marketed by Bonneville. In addition, Bonneville's transmission system exceeds 15,000 circuit miles, provides more than three-fourths of the region's high-voltage transmission capacity, and includes major transmission links with Canada and other regions within the United States.

BPA has many public responsibilities. It is obligated, under the Federal Columbia River Transmission System Act (Transmission System Act) to plan, construct, operate and maintain a Federal transmission system within the Pacific Northwest to provide transmission service that the Bonneville Administrator determines necessary and appropriate, and to be the primary transmission provider for the Pacific Northwest region. Other public responsibilities include marketing cost-based power and transmission so as to assure the widest possible use of power at the lowest possible rates; giving public and regional preference to power; promoting conservation and renewable resource development; mitigating fish and wildlife losses; complying with industry safety and reliability standards; complying with the Endangered Species Act and the National Environmental Policy Act; maintaining tribal relationships; and repaying the Federal taxpayers' investment.

Bonneville's rates currently are developed through a formal regional process pursuant to certain ratemaking standards and filed with FERC for approval or remand under those standards. One of BPA's primary duties is to establish power and transmission rates to repay "the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs." 16 U.S.C., § 839e(a)(2)(A). These other costs include amounts attributable to efforts to mitigate and enhance fish and wildlife populations in the Columbia River basin, which currently exceed $400 million annually, and over $7 billion in Washington Public Power Supply System and other Bonneville-backed debt. At the end of Fiscal Year 1997, Bonneville's outstanding Treasury repayment obligations exceeded $7.6 billion.

Since 1974, Bonneville has operated on a non-appropriated, self-financing basis. The Transmission System Act directs Bonneville to deposit its revenue from ratepayers directly into the Bonneville revolving fund for payment of its costs. All of Bonneville's costs are general obligations of the single Bonneville fund. The Transmission System Act allows Treasury to be repaid only after other Bonneville financial obligations are met. Bonneville also uses permanently authorized Treasury borrowing authority, now totaling $3.75 billion, to finance capital investments.

In 1996, the governors of Idaho, Montana, Oregon and Washington, with the support of the Department of Energy, convened the Comprehensive Review of the Northwest Energy System to "develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry . . . designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same time assuring the region of an adequate, efficient, economical and reliable power system." Among its recommendations to facilitate an open and competitive regional power market, the Review proposed that Bonneville's transmission function be separated from generation, that Bonneville's transmission be made subject to FERC regulation equivalent to the Commission's regulation of investor-owned utilities, and that Bonneville be allowed to recover stranded costs. The Review cautioned that legislation be undertaken in a manner that would not "jeopardize or diminish the legal obligation and ability of Bonneville to meet its fish and wildlife and other obligations."

In 1997, the governors of the four states convened a Transition Board to facilitate implementation of the recommendations of the Regional Review. With regard to transmission, the Board issued a proposal to subject the BPA transmission function to FERC regulation under numerous provisions of Parts II and III of the Federal Power Act, subject to various qualifications. With regard to the qualifications, the Transition Board observed that "Bonneville differs in several important ways from the utilities FERC currently regulates. Consequently, the transmission work group identified a number of exceptions to the usual application of the Federal Power Act that take Bonneville's unique character into account."

Issue 1. TRANSMISSION JURISDICTION – Should BPA be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act for determining transmission rates, terms and conditions?

Recommendation: Subject BPA to FERC authority under sections 205 and 206 and any other relevant provisions of the Federal Power Act for purposes of determining transmission rates, but condition FERC's exercise of its authority so as to assure that BPA meets its other recognized responsibilities.

The Administration Plan proposed that BPA transmission rates be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act. Sections 205 and 206 require FERC to review proposed transmission rates under its just and reasonable and not unduly discriminatory standard. Providing FERC with uniform jurisdiction over all transmission owners would enable FERC to ensure the development of open and competitive wholesale markets. Moreover, application of sections 205 and 206 authority would enable FERC to apply its open transmission access requirements to BPA.

While DOE supports the application of FERC's sections 205 and 206 jurisdiction to BPA with regard to their transmission rates, because of the other important responsibilities of BPA, and the need to assure that the federal investment in the federal power system is repaid, we recommend that FERC's exercise of its authority under sections 205 and 206 be conditioned to assure that Bonneville can meet its cost recovery and other statutory obligations.

Issue 2. PARTICIPATION IN AN INDEPENDENT SYSTEM OPERATOR -- Should BPA be permitted to join an ISO on a voluntary basis?

Recommendation: Authorize BPA to turn over operational control of transmission facilities to an independent system operator.

The Administration bill gives FERC the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator (ISO) to facilitate competition. An ISO would allow for the independent operation and control of transmission facilities separate from a utility's marketing functions. BPA is included within the definition of transmitting utilities, and it is the intent of the bill to ensure that FERC has the authority to require BPA participation in ISOs.

There may be some question, however, regarding the legal authority of BPA to participate in an ISO in the absence of an order from FERC.2 We recommend that a provision be added to the bill to clarify that BPA may voluntarily participate in an ISO.

Issue 3. RECOVERY BY BPA OF NON-RECOVERABLE COSTS – Should a mechanism be established to enable BPA to recover future non-recoverable costs?

Recommendation: Allow the Administrator to propose and the Commission to establish a cost recovery transmission surcharge mechanism to provide for the recovery of otherwise nonrecoverable costs, such as future additional fish and wildlife costs. The recovery would be limited to no more than $50 million a year, with a maximum possible recovery of $400 million between October 1, 2001 and October 1, 2016. In order for the recovery to take place, power business line reserves must be below $145 million. The amounts collected through the surcharge shall be treated as a loan to BPA's power function.

Under FERC's definition of stranded costs, a utility may recover as stranded costs only historical embedded costs. Losses for future investment do not satisfy the definition of stranded costs because utilities presumably have control over their investments once retail competition is introduced. Unlike other utilities, however, BPA has a significant future cost variable over which it has no control --- fish and wildlife costs, which is estimated to range from $438 to $721 million annually for the 2002-2006 period.

Under most estimates of future market conditions, Bonneville is expected to be able to recoup all of its costs. However, if alternative power prices were to unexpectedly fall below Bonneville's, or if BPA's costs were to unexpectedly rise substantially, a cost recovery mechanism would be needed to avoid shifting the responsibility for payment to the United States Treasury.

DOE recommends that the Administrator be given the authority to propose, and the Commission the authority to approve, a transmission surcharge mechanism that is equitable and designed to minimize bypass of the transmission system. DOE recommends that the recovery be limited to no more than $50 million a year, with a maximum possible recovery of $400 million between October 1, 2001 and October 1, 2016. This latter date is the date by which most of Bonneville's third-party financing costs will be retired. In order for the recovery to take place, power business line reserves must be below $145 million, an amount historically calculated to ensure Treasury repayment.

DOE further recommends that any amounts collected through the surcharge mechanism be treated as a loan to Bonneville's power function, and that the loan be repaid with interest once the power function is able to meet its cost recovery and Treasury repayment obligations on an annual basis. This requirement conforms to current requirements that the power and transmission functions each fully pay their own costs over time, and further diminishes any possibility that the surcharge mechanism be viewed as a vehicle to enhance the competitiveness of Bonneville's power products.

C. THE WESTERN AREA POWER ADMINISTRATION AND THE

SOUTHWESTERN POWER ADMINISTRATION

Congress enacted the Reclamation Acts in the early part of this century to develop irrigation projects for the reclamation of arid and semi-arid western United States lands and included in these Acts provisions for the generation of hydroelectricity at these facilities. The Bureau of Reclamation managed these projects and sold the excess power from the projects. Pursuant to the Flood Control Act of 1944 and prior acts, flood control projects were developed by the Department of the Army (Corps of Engineers), and the surplus hydroelectric power at these projects was sold by the Department of the Interior. The Western Area Power Administration (WAPA), The Southwestern Power Administration (SWPA), and the Southeastern Power Administration (SEPA)3 market surplus power from facilities constructed under the Reclamation Acts and the Flood Control Act of 1944. Following the enactment of the Department of Energy Organization Act, the power marketing functions from the Reclamation and Flood Control Acts were transferred to the Department of Energy, acting by and through the Administrators of these Power Marketing Administrations (PMAs).

As marketers of federal power, WAPA and SWPA must satisfy certain statutory requirements. Such entities must give a preference in the sale of power to municipalities and other public bodies or agencies, and to electric cooperatives. WAPA and SWPA are required to set rates for electric power sales that cover costs. Once WAPA or SWPA develops appropriate rates consistent with governing statutes and regulations, the Deputy Secretary of Energy, under authority delegated by the Secretary of Energy, approves the rates on an interim basis, and FERC conducts a review of the rates to determine whether they are the lowest possible to customers consistent with sound business principles and whether the revenues generated by the rates are sufficient to recover the costs of producing and transmitting the electric energy. The Commission may reject the rate determinations only if it finds them to be arbitrary, capricious, or in violation of the law. The Commission does not develop a record of its own, but only affirms or remands the rates submitted to it for final review.

Issue 1. TRANSMISSION JURISDICTION – Should WAPA and SWPA be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act for determining transmission rates, terms and conditions?

Recommendation: Subject WAPA and SWPA to FERC authority under sections 205 and 206 of the Federal Power Act for purposes of determining transmission rates, but condition FERC's exercise of its authority so as to assure that SWPA and WAPA meet their other recognized responsibilities.

The Administration Plan proposed that PMA transmission rates be subject to FERC jurisdiction under sections 205 and 206 of the Federal Power Act. Sections 205 and 206 require FERC to review proposed transmission rates under its just and reasonable standard. Providing FERC with uniform jurisdiction over all transmission owners would enable FERC to ensure the development of open and competitive wholesale markets. Moreover, application of sections 205 and 206 authority would enable FERC to apply its open transmission access requirements to WAPA and SWPA.

While DOE supports the application of FERC's sections 205 and 206 jurisdiction to WAPA and SWPA with regard to their transmission rates, because of the other important responsibilities of these entities, and the need to assure that the federal investment in the federal power system is repaid, we recommend that FERC's exercise of its authority under sections 205 and 206 be conditioned to assure that these PMAs can meet their cost recovery and other statutory obligations.

Issue 2. PARTICIPATION IN AN INDEPENDENT SYSTEM OPERATOR -- Should WAPA and SWPA be permitted to join an ISO on a voluntary basis?

Recommendation: Authorize WAPA and SWPA to turn over operational control of transmission facilities to an independent system operator.

The Administration bill gives FERC the authority to require transmitting utilities to turn over operational control of transmission facilities to an ISO to facilitate competition. An ISO would allow for the independent operation and control of transmission facilities separate from a utility's marketing functions. WAPA and SWPA are included within the definition of transmitting utilities, and it is the intent of the bill to ensure that FERC has the authority require WAPA and SWPA participation in ISOs.

There may be some question, however, regarding the legal authority of WAPA and SWPA to participate in an ISO in the absence of an order from FERC. (See note 2, supra.) We recommend that a provision be added to the bill to clarify that WAPA and SWPA may voluntarily participate in an ISO.

II. EFFICIENT GENERATION TECHNOLOGIES AND REMOTE POWER

A. ENCOURAGING DISTRIBUTED POWER AND COMBINED HEAT AND POWER TECHNOLOGIES

Distributed power ("DP") is any small-scale power generation technology that is intended to serve a discrete set of consumers at a site closer to these consumers than a central generation station. While the size of central generation stations typically range from 200 MW to 1,200 MW, distributed power is generally substantially smaller. Small low-cost modular generators include fuel cells, gas turbines, and micro turbines, as well as combustion engines, wind, photovoltaics, and small-scale hydropower.

Distributed power offers numerous benefits. First, because it is sized to satisfy a single user's on-site requirement or to serve a group of users close to the source, costly upgrades to the transmission and distribution systems can be avoided. Second, generating power at the site where it is used is more efficient because it avoids energy losses that occur along transmission and distribution lines. Third, distributed power enables large commercial and industrial customers to shave their peak power needs, thereby reducing their costs while providing reliability benefits to all users of the transmission and distribution systems. Fourth, distributed power provides substantial environmental benefits through the introduction of cleaner, more efficient technologies. Finally, distributed power can provide customers with standby, emergency power or high-quality uninterruptible power for critical applications.

Combined heat and power ("CHP") is defined as a system using a single fuel source to produce either electric or mechanical power and useful thermal energy at the point of use. By combining heat and power production, up to 90 percent of the useful energy in fuel can be put to beneficial use in some applications, in contrast to the 33 percent conversion efficiency in typical conventional steam-electric generating plants. By making use of energy that would be wasted in a facility dedicated solely to either power or heat production, CHP systems can lower energy costs and reduce the amount of fossil fuels required to meet the total power and heat needs of an industrial facility or a building, leading to reductions in emissions of greenhouse gases and other pollutants. Many clean distributed power technologies also offer new opportunities for small-scale combined heat and power applications.

Competition itself will be an important spur to more efficient fuel use, since fuel cost savings will allow power suppliers to increase profits. Efficient combined heat and power applications will be particularly attractive in this regard. In contrast, under cost-of-service regulation the electricity industry was not encouraged to make efficient use of fuel in generation, because fuel costs were directly "passed through" to customers as a part of regulated rates.

Competition should also be beneficial to distributed power applications. Businesses will be forced to view electricity supply arrangements from a new perspective. Faced with a real choice and the opportunity to design and implement corporate-wide strategies for meeting energy needs at multiple sites now served by different suppliers, businesses are more likely to choose firms that specialize in comprehensive energy management. Energy specialists will be well-equipped to keep current on advanced distributed power technologies and identify applications where they can cost-effectively meet energy needs.

While retail competition itself will provide an important impetus to the development of both DP and CHP systems, a number of other significant barriers impede the effective deployment of these technologies. Given the significant economic, reliability, and environmental benefits of these technologies, a truly comprehensive plan for the electricity sector should include actions to reduce these barriers. As described below, DOE recommends that the Administration pursue actions that would: (1) remove tax disincentives for CHP and DP technologies; (2) encourage states to offer favorable transition cost treatment to CHP and DP technologies (following the lead of some states that have already implemented retail competition); (3) reduce barriers to the interconnection of CHP and DP systems within the electricity supply network; (4) provide grants for the deployment of DP technologies in rural and remote areas; and (5) encourage administrative actions to lower regulatory barriers to CHP and DP technologies in the permitting process.

Issue 1. REMOVING TAX DISINCENTIVES FOR COMBINED HEAT AND POWER AND DISTRIBUTED POWER -- Should depreciation schedules be revised to eliminate existing biases against efficient and environmentally-preferred CHP

and DP technologies?

Recommendation: **All equipment used in combined heat and power and distributed power facilities would have a tax life of 7 years for purposes of depreciation. This approach would be roughly consistent with the treatment of comparable equipment used in industry-specific asset classes.**

Principal Option: **Depreciate CHP and DP equipment used in buildings within a new asset-based class rather than under the 39 year straight-line depreciation schedule now used, to level the playing field for competition between central station and DP/CHP technologies.**

Other Option: **Undertake a study of the depreciation treatment of CHP/DP technologies and provide recommendations to Congress for any necessary changes. The study should explicitly consider: the direct competition between CHP/DP and central station generation in meeting energy supply needs, the environmental benefits of CHP/DP, and technological changes in CHP/DP.**

The present tax code treatment of combined heat and power ("CHP") and distributed power ("DP") technologies has the effect of discouraging their use in many types of applications. Depreciation lifetimes for particular pieces of equipment, such as turbine engines, are typically much longer when the equipment is used as part of a CHP or DP facility than when it is used in another application, such as airplane propulsion. A particularly extreme situation arises with respect to CHP and DP technologies used in commercial buildings, which are treated as structural components and are therefore subject to straight-line depreciation over a 39 year lifetime.

Tax issues are inherently complex, and there are other situations where the same equipment used in two industries (for example, bulldozers used in farming and construction), have different depreciation lifetimes. However, there are several unique factors relevant to the case of CHP and DP equipment that merit attention:

-The electricity produced by CHP and DP technologies substitutes directly for the electricity produced by central-station plants in meeting total load requirements. Unlike the case of bulldozers in farming and construction, which are also depreciated according to different schedules, the different power generation technologies compete directly for the same market.

-The environmental advantages of CHP and DP in reducing emissions and waste magnify the public interest in avoiding depreciation policies that penalize CHP and DP technologies relative to central station generation technologies. A depreciation policy that tilts the playing field against these technologies inadvertently increases emissions and waste.

-There have been radical changes in CHP and DP technologies since the time when current depreciation rules were established.

In the view of DOE, CHP and DP technologies should be encouraged by instituting a permanent change in the depreciation schedule for CHP and DP equipment.

Issue 2. FAVORABLE TRANSITION CHARGE TREATMENT FOR EFFICIENT COMBINED HEAT AND POWER AND DISTRIBUTED POWER SYSTEMS FOR ON-SITE GENERATION – Should the Administration bill encourage favorable transition charge treatment for these technologies?

Recommendation: Amend PURPA to require state regulatory bodies to consider the appropriate mechanism under state law to reduce

> **transition charges for customers using onsite renewable technologies, fuel cells, or combined heat and power technologies with a minimum efficiency of 50 percent.**

The Administration's bill includes language requiring state regulatory authorities, as a part of a public proceeding to consider implementation of retail competition, to also consider the appropriate mechanism under state law to address recovery of retail stranded costs. If a state chooses to provide for stranded cost recovery, it must determine who will pay these costs and how they are to be assessed. Some states, such as California, have adopted strict rules to prevent consumers from avoiding charges imposed on distribution customers through the installation of on-site generation facilities. An exit fee imposed on consumers switching to on-site generation could serve to discourage CHP and DP installations even in cases where they would otherwise be economically attractive and might have been pursued in the absence of a shift to competitive markets.

Some states have made a different choice. For example, Massachusetts exempts a consumer from an exit fee charge if that person reduces purchases of power from the grid through the operation of onsite renewable energy technologies, fuel cells, or cogeneration equipment with a combined heat and power system efficiency of at least 50 percent. Smaller cogeneration facilities ($\leq$ 60 kilowatts) which are eligible for net metering are also exempt from transition charges. The Massachusetts State Department of Telecommunications and Energy has the authority to revoke the exemptions if they would have a significant adverse impact upon the bills of other customers.

Our recommendation would require that states holding proceedings to consider stranded cost recovery also examine whether favorable treatment should be given to consumers employing efficient on-site technologies. This approach would be consistent with the Administration principle of empowering, but not requiring, states to implement retail competition.

Issue 3. REDUCING REGULATORY IMPEDIMENTS TO CHP AND DP -- What administrative or statutory changes in air quality regulation are appropriate to encourage the deployment of combined heat and power and distributed power technologies?

Recommendation: Reinforce through an Administration statement, possibly including timing details and explicit direction, EPA's current administrative direction toward performance- and output-based environmental standards. Expedite the development of emissions standards and allowances to account for both electricity produced and used heat output from facilities. Promote performance- and output-based environmental standards in Federal and state air programs.

Option: Provide new authority to relieve innovative and high efficiency DP and CHP technologies of certain site-specific air quality regulatory requirements and provide new EPA/DOE authority to set efficiency and emissions standards for technologies qualifying for this relief.

The Administration's bill is projected to provide net benefits to the environment by reducing emissions of nitrogen oxides (NOx) and carbon. Administrative requirements under the Clean Air Act, however, may unnecessarily discourage the deployment of combined heat and power and distributed power facilities. This may prevent achievement of the fullest possible environmental (air quality) and economic benefits of these facilities within a competitive industry.

In setting categorical emissions standards under new source or toxic air pollutant provisions of the Clean Air Act, EPA is required to consider the energy requirements of its standards (See Clean Air Act sections 111(a)(1) and 112(d)(2)). In the past, these standards have generally not fully addressed the air quality benefit of emissions avoided through the efficiency provided by CHP and distributed power. For example, power generation emissions standards have been set on an input basis, which does not encourage more efficient technologies.

More recently, Federal and state environmental regulators have been considering output-based approaches in standard-setting. Accordingly, EPA could be directed to expedite periodic reviews of national emissions standards applicable to power generation and revise them to the form of output-based standards wherever appropriate. In addition, in setting any new standards for power generation, EPA could be directed to actively seek to establish output-based standards. Where it becomes necessary and appropriate for Federal emissions allowance allocations, EPA has the authority and can adopt an output-based allocation methodology.

Under the Recommendation, the responsibility to issue air quality permits for new facilities would remain primarily with the states, since they have the obligation of ensuring that ambient standards within their borders are met. Although Federal statutory requirements vary based on the amount of emissions and location of a facility, transaction costs for developing a permit application can be a deterrent, particularly for smaller facilities, regardless of proposed location. Increased standardization of technology and emission specifications, and in permit application data, could reduce these costs, expand voluntary participation in emissions trading programs, and provide the technical information needed for regulatory acknowledgment of emissions avoided by permitted electric generation at the point of use.

The other option, advocated by some CHP/DP advocates, would amend the Clean Air Act to provide that facilities which meet a prescribed efficiency and output-based (thermal and electrical) emissions level would be "certified" to meet a variety of requirements under the Act. Since these requirements deal with the impact that a particular facility has on air quality, states would need to address these emissions by further controlling other new and/or existing sources. The variety in the types of technologies -- and applications -- which are, or will be, available for waste heat recovery and electric generation is broad and ever evolving, and may not be amenable to legislative setting of efficiency-based standards.

Issue 4. INTERCONNECTIONS FOR ON-SITE GENERATING FACILITIES – What actions should be taken to facilitate interconnection of CHP and DP facilities with the grid?

Recommendation: On-site generating facilities should be entitled to interconnection with the distribution grid for purposes of sales, access to backup power, or for any other reason determined appropriate by the Federal Energy Regulatory Commission. DOE should prescribe safety and power quality standards and rules necessary for interconnections of an on-site generating facility with a distribution system.

The ability to interconnect new generation to the electrical grid is critical to achieving the economic and environmental benefits of competitive electricity markets. Unwarranted impediments to interconnection provide a means for incumbent utilities to prevent entry and exert market power. For this reason, the Administration bill includes a provision that clarifies the Federal Energy Regulatory Commission's authority over interconnection to the grid.

There is no "bright line" distinction between transmission and distribution systems. Existing PURPA provisions already provide for a federal mandate for assuring the interconnection of qualifying facilities to the transmission and distribution grid. Appropriate provisions to assure interconnection that are already applicable to CHP and DP facilities are included in the Administration's bill, but as an element of the net metering provision. DOE proposes to include the interconnection authority as a separate provision in the bill.

Generic technical standards for interconnection of small facilities are already being developed under the auspices of The Institute of Electrical and Electronics Engineers. Providing DOE with the authority to approve these or alternative standards ensures that any new generator, assuming safety and power quality standards are met, will be entitled to interconnection to the distribution grid.

B. ENCOURAGING INSTALLATION OF ADVANCED AND EFFICIENT DP TECHNOLOGIES IN REMOTE COMMUNITIES.

A truly comprehensive electricity proposal should include programs to address the electricity needs of remote communities that do not have substantial access to the electric grid. Such programs, which are discussed below, could promote the use of advanced and efficient DP technologies in suitable applications.

Issue 1. REMOTE COMMUNITIES – How can the electricity needs of remote communities be addressed?

Recommendation: Authorize electrification grants for remote communities, to be funded through annual appropriations.

Option: Provide resources for remote community electrification through the Public Benefits Fund.

The Comprehensive Electricity Competition Plan proposed by the Administration is projected to provide significant benefits to electricity consumers connected to the three major power grids that serve the continental United States by accelerating the transition to competitive electricity markets. However, a strong argument can be made that the first comprehensive overhaul of the federal statutory framework for the electricity industry in over 60 years should aim to provide the economic and environmental benefits of improved electricity service and technology to all customers, irrespective of location.

In this regard, the situation of remote communities not connected to the major power grids merits particular attention. Communities in Alaska and elsewhere that are not connected to the grid also face high costs and environmental concerns, which together can pose a significant barrier to economic development.

Many clean and efficient generation technologies are becoming available for small off-grid or end-of-line loads. These include small gas turbines, fuel cells and renewables such as solar, wind and small hydropower. These distributed power technologies can provide small remote communities with a source of clean, affordable electric power. The deployment of such technologies can also serve as a model for their use in more populated areas faced with distribution constraints, where power quality is an important concern, or where combined heat and power can produce both cost savings and environmental benefits.

To help residents of remote areas, the Administration's legislation should authorize appropriations for grants to address the electricity needs of small, remote communities that are not connected to the national transmission grid, or where costly transmission or distribution reinforcements are needed to serve growing loads. Such communities frequently are forced to rely upon expensive, older, polluting, generation technologies and would not benefit from provisions included in the original Administration proposal because they do not have the option of importing less expensive, cleaner electric power through the interconnected grid. In order to qualify for grants, a community would have to demonstrate that it is not connected to the national transmission grid or has limited or constrained connections and that the cost of power in the community exceeds 150% of the national average cost of power. The community could be any recognizable local government or Indian tribe of not more than 10,000 individuals. Senate Minority Leader Daschle and Energy Committee Chairman Murkowski co-sponsored a similar proposal in the last Congress.

Another option to support remote power initiatives would be to establish a mechanism tied to the Public Benefits Fund (PBF) already included in the Administration's bill. While this approach could help to broaden the base of support for the Fund, it would be difficult to weed out funding for electricity supply to remote vacation home communities owned by wealthy individuals, that might qualify under an "entitlement" approach. For this reason, funding of remote power initiatives through the PBF is not recommended.

Issue 2. SOUTHEAST ALASKA ELECTRICAL INTERTIE SYSTEM – How can the electric systems of communities in Southeast Alaska be connected to promote efficiency and benefit the environment?

Recommendation: An appropriation should be authorized to help construct, along with state and local funds, a transmission intertie in Southeast Alaska to connect communities and provide for a more efficient and environmentally friendly electric system.

As the population and business activity in Southeastern Alaska has grown, the demand for electricity has significantly increased. Unfortunately, because there is no electric grid to speak of, almost every community in Southeast Alaska is required to generate its own power. Although there is a substantial amount of hydropower capacity and potential in the region, many small communities are forced to rely on diesel generation, which is both more expensive and harmful to the environment. In addition, some of the larger cities are utilizing their full capacity of hydropower and are on the verge of having to meet new demand with diesel-fired generating capacity.

Several years ago, interested parties in Alaska proposed the construction of a 57 mile, 138 kv electric transmission line to connect the Swan Lake hydroelectric project, which serves Ketchikan with the Tyee Lake hydroelectric project that serves the communities of Petersburg and Wrangell. The project is estimated to cost a total of $73 million. While Ketchikan fully utilizes the power generated at the Swan Lake dam, Petersburg and Wrangell need only a small portion of the power that can be generated at Lake Tyee. If the proposed intertie is not constructed, Ketchikan will be forced to construct additional generating capacity, some of which will come from noisy, polluting and expensive diesel generators.

In Fiscal Year 1998, Congress appropriated $10 million of an estimated $30 million in requested federal funds to help construct the intertie. However, no funds were appropriated in FY99, in part, because of objections that the project was not authorized. The project's future is uncertain without further federal funding.

III. CONSUMER PROTECTION

The introduction of retail competition will offer substantial economic and environmental benefits to consumers. The Department projects $232 in annual savings to the typical family of four, including $104 in direct savings on household electricity bills. Nevertheless, DOE is mindful that unless consumers are adequately protected in these new markets, they may not realize the full benefits of retail competition. The Administration's bill therefore includes a provision requiring standardized information disclosure that will enable consumers to make wise choices. The bill also includes provisions to protect consumers from utilities wielding market power. In this section of the memorandum, DOE proposes additional provisions to protect consumers in competitive retail markets.

Issue 1. LOW-INCOME ACCESS TO ELECTRIC SERVICE – How can low-income consumers be assured access to alternative suppliers in competitive markets?

Recommendation: Amend PURPA to require states to hold proceedings to consider a federal principle that all consumers in the state shall have reasonable access to competitive suppliers.

Advocates for low-income consumers have expressed concern that these consumers might not share in the benefits of retail competition. They suggest that, for a variety of reasons, low-income consumers may not be as attractive a market as other residential consumers. All states that have implemented retail competition have established a supplier of last resort, which is intended to assure that all customers in the state have access to retail electric service. However, a supplier of last resort does not guarantee that consumers have access to "affordable" electric service. As with other market segments, the opportunity for real customer choice among a set of alternative suppliers would provide low-income consumers the best opportunity for economical electricity.

The Administration's bill proposes to establish a Public Benefits Fund which would make funding available, on a matching basis, to the states for low-income electricity assistance programs. While these programs are beneficial, they do not ensure that low-income consumers will receive the same benefits associated with retail competition as others. Instead, low-income consumers would be more likely to reap these benefits if states were to review the potential for "redlining" with regard to electric service. This approach would be consistent with other elements of the Administration's proposal by allowing states to retain the flexibility to establish their own approach to protect low-income consumers.

Issue 2. CONSUMER PROTECTION AGAINST "SLAMMING" AND "CRAMMING"-- How can protections against fraudulent practices that might arise in competitive markets be strengthened?

Recommendation: Add provisions to the Administration bill which would authorize the Federal Trade Commission to enforce requirements preventing retail electric suppliers from engaging in the practices of "slamming" and "cramming".

"Slamming" is the practice of changing a customer's service provider without that customer's knowledge. "Cramming" is the practice of billing a customer for unauthorized or fictitious service. Both slamming and cramming have been a problem in the competitive long distance and emerging competitive local telephone markets. These practices have generated numerous complaints at the Federal Communications Commission (FCC), the Federal Trade Commission (FTC), and at state public utility commissions. The FCC has established procedures for verification of service change requests. In addition, the 1996 Telecommunications Act directed the FCC to establish rules against slamming and cramming.

There is concern that slamming and cramming will also occur in a competitive retail electric market. Experience in the telecommunications field demonstrates the desirability of providing clear federal authority to address such abuses. In contrast to telecommunications, where the FCC has historically had the primary role for consumer protection, FERC has not played any role in the regulation of retail electric service. While the FTC has no history specifically with regard to the electric service, that Commission is best equipped to implement a consumer protection program.

Issue 3. AGGREGATION – Should protections be included in the bill to ensure that customers can aggregate their load in order to increase their purchasing power?

Recommendation: Authorize any person, corporation, cooperative or any other governmental entity to purchase retail electric energy on behalf of the members of a group served by one or more distribution utilities subject to retail competition.

Some have expressed concern that, when retail electric markets are opened to competition, not all consumers will have the same access to competing suppliers. Small, rural communities might not be as attractive to power marketers as more densely populated urban areas and residential consumers might not have access to the same number of suppliers as industrial customers with large loads. These consumers will only be able to develop sufficient purchasing power through the process of aggregation. In addition, businesses with many sites in a region or around the country may also want to increase their purchasing power.

Aggregation is the ability of electric consumers to join their load in order to leverage buying power. An aggregate can have an efficient size, the sophistication to shop electricity markets for lower prices, and the diversity of various customer loads to be able to obtain beneficial price offers from suppliers. Aggregators can include municipalities, cooperatives, buying clubs and for-profit brokers and marketers.

Aggregation is an important tool to ensure that consumers benefit from retail competition. While most states will encourage aggregation, it is essential that state and Federal laws not impose barriers for any entity to participate in aggregation. Therefore, we recommend that the Administration bill make it clear that no state or Federal law can be applied to impede aggregation in a state or area that has proceeded with retail competition.

Issue 4. AVAILABILITY OF INFORMATION – How can consumers effectively compare the choices available pursuant to retail competition?

Recommendation: Create a publicly accessible "Electricity Shopper" database at the Department of Energy.

As has been the case with competition among telecommunications service providers, electricity consumers could very well be subject to an array of confusing offers from competing electricity marketers. The different terms and services offered may make it difficult for the average residential consumer to make the most advantageous decision. The Administration bill already requires electricity suppliers to provide certain economic and environmental information about the products they are offering directly to consumers. However, access to this information will not necessarily enable a consumer to adequately compare the services being offered by different suppliers.

DOE recommends that it be authorized to establish an "Electricity Shopper" database and website to enable consumers to make easy comparisons of the different services they are being offered. The Electricity Shopper site would also provide consumers access to energy-efficiency and conservation information for both electricity purchase and use options available to save money and improve the environment. Combining disclosure and efficiency information in a single visible tool should enable consumers to become well educated shoppers.

Issue 5. MODEL RETAIL SUPPLIER STANDARDS – How can the Federal government best facilitate state efforts in licensing retail electricity suppliers?

Recommendation: Authorize DOE to draft and make available to the states a Model Code proposing certain minimum standards on retail electricity suppliers that should be established to protect consumers.

State public service commissions, in regulating most utilities, generally ensure that utilities have sufficient financial resources to enable them to meet their obligations to provide consumers with electric service. When retail competition is implemented, the number of suppliers operating in a given state could increase exponentially. State regulators will most likely seek to impose certain requirements on marketers as a condition for selling electricity to consumers in their states. However, unlike the regulation of traditional vertically integrated utilities, most electricity suppliers will be located beyond state boundaries and regulation of these suppliers may require substantial increases in resources. The federal government can help enable states to protect consumers from "fly by night" electricity providers by making model legislation available to states to help them establish requirements that would protect consumers. While the Model Code would create a Federal benchmark, in keeping with the spirit of the Administration Plan, it would allow the states flexibility to adopt their own approaches for consumer protection.

Issue 6. ELECTRIC UTILITY COMPANY MERGERS – Should FERC be required to consider the effect of a merger on retail competition during a merger proceeding?

Recommendation: Amend the Federal Power Act to clarify that, in reviewing utility mergers, the Federal Energy Regulatory Commission must examine the impact of the merger on the competitiveness of retail markets, after consultation with the states.

Section 203 of the Federal Power Act requires that FERC review the sale or merger of jurisdictional facilities (i.e. transmission facilities and jurisdictional power sales contracts) and, before approving the transaction, must find that the transaction is consistent with the public interest. In performing its duties under this section, the Commission has reviewed the impact of mergers and acquisitions on the competitiveness of wholesale electric markets but generally has reviewed the effect on retail markets only where an affected state commission has no authority or insufficient resources to do so and has raised concerns about the effect of the merger on state regulation.

While a state utility commission typically has authority over mergers involving an electric utility located in the state, a neighboring state would not have jurisdiction and accordingly would have no authority to consider the effects of the merger on that state. Since a merger between utilities located in one or more states can impact the competitiveness of retail electric markets in an entire region, it is appropriate for FERC to examine if the merger would create undue market power or other conditions that would adversely affect retail consumers.

IV. RELIABILITY

Retail competition is expected to provide a number of benefits to the consuming public, the economy and the environment. However, some have expressed concern that competition will put new and unusual pressures on transmission and distribution systems that were planned and built to serve an entirely different industry structure and that reliability could be imperiled.

The Administration's Plan contains broad principles calling for the application of mandatory reliability standards by a self-regulating organization with FERC oversight. The reliability language was drafted based on the recommendations of the Secretary of Energy Advisory Board Task Force on Electric System Reliability ("Task Force") and on detailed legislative principles agreed to by a task group formed by the North American Electric Reliability Organization (NERC), of which DOE is a member. The task group, like the Department's Task Force, is composed of every major stakeholder group, as well as representatives from the current regional reliability councils.

The task group has continued to meet and is in the process of developing consensus legislation, using the Administration language as the starting point. The work of the group should be completed by the end of January. Once consensus is reached, and to the extent DOE supports the consensus language, DOE will recommend replacement of the existing Administration language developed by the consensus group and may also recommend an appropriate role for the Federal government.

Issue 1. ELECTRICITY OUTAGES – What can be done to investigate significant power outages and prevent future problems?

Recommendation: Create an Electricity Outage Investigation Board to investigate major electricity outages and report its findings to the Secretary of Energy.

As the nation becomes increasingly reliant on computers and other electronic innovations, major power outages have wreaked havoc on businesses and homes. It is essential that both states and the federal government develop tools to minimize both the occurrence and impact of these outages. It would be helpful if there were a source of unbiased information regarding major electricity outages and their causes because findings of fact may become increasingly difficult over time as industry organizations seek to avoid liability.

The Department of Energy has traditionally been relied on to evaluate power system failures and develop recommended actions to minimize recurrences. However, without a dedicated in-house capability, it would be difficult for DOE to carry out this function in an increasingly complex competitive market. Concerns have also been raised about the objectivity of analyses which draw heavily on industry sources.

These concerns could be addressed by establishing a board of experts to investigate and report on significant electric outages. An Electricity Outage Investigation Board would be empowered to investigate major incidents and report its findings and recommendations to prevent future outages to the Secretary of Energy. The Secretary, upon receipt of the Board's report, would be able to propose changes to existing reliability standards and other actions necessary to prevent future outages.

Issue 2. TRANSMISSION ADDITIONS – How can the federal government help facilitate state decisions related to the addition of transmission capacity?

Recommendation: Permit the Secretary of Energy to convene joint federal-state meetings to consider the addition of transmission capacity additions.

Utility decisions to build transmission capacity are generally regulated by the states. While this system generally worked well when vertically integrated utilities generated electricity, transported the electricity to their distribution systems, and distributed it to consumers, competition has increased the demand for use of existing transmission capacity. In some cases, existing transmission is already being fully utilized and power marketers' access to certain markets is severely limited. While the addition of transmission capacity could alleviate some of these situations, states are, at times, being asked to approve the construction of transmission facilities for the benefit of consumers in other states. Given the environmental, health and aesthetic concerns associated with transmission lines, states sometimes are reluctant to approve new facilities.

DOE recommends that the Secretary be given the authority to initiate meetings with representatives of the states in a region needing additional transmission capacity. These meetings would be intended to develop consensus approaches for alleviating regulatory problems associated with transmission constraints.

V. MISCELLANEOUS ITEMS

Issue 1. INDIAN TRIBE ASSISTANCE -- How can the federal government ensure that Indian tribes benefit from the transition to retail electric competition?

Recommendation: Federal legislation should (1) enable the Department of Energy to provide Indian tribes with the information necessary to determine the best way to participate in electricity markets; (2) create a grant program to allow tribes to add the infrastructure necessary to generate and/or purchase electricity to serve tribal needs; and (3) create tax incentives to promote tribal participation in the competitive generation markets.

The Administration's bill encourages states to adopt retail competition to improve generation efficiency, lower electricity costs, and improve the environment. Some Indian tribes, however, might not be able to fully realize these benefits. For example, it has recently been estimated that over 25,000 households on the Navajo reservation do not have electric service. Indian reservations, being autonomous nations, do not come under the jurisdiction of states. State laws restructuring the electric industry will likely have a mixed impact on Indian tribes. In some cases, Indian tribes have organized electric systems and can generate or make electricity purchases to serve tribal electricity needs. In other cases, tribal members must deal directly with the local distribution utility.

Analysis is needed to assess the most cost-effective and efficient means for Indian tribes to participate in new electricity markets. Indian tribes will need to establish appropriate regulatory and physical infrastructures to serve tribal needs. DOE could provide tribes expertise and grants, in consultation with the Secretary of the Interior, to analyze tribal electricity needs, the availability of natural resources for electricity generation, opportunities for transmission enhancement/construction, and effects of state restructuring programs on tribal electricity supplies.

In addition, funding should also be authorized for electricity infrastructure grants to Indian tribes. These grants would be used for, but not limited to:

- creation of a tribal regulatory authority for the development, administration, implementation, and enforcement of tribal laws and regulations governing the generation, transmission, and distribution of electricity on Indian reservations;

- the training and education of employees responsible for enforcing or monitoring compliance with Federal and tribal laws and regulations; and

- planning and development of physical infrastructure facilities for the generation, transmission, and distribution of electricity to serve tribal needs.

The infrastructure grants to tribes would also be issued by the Secretary of Energy following consultation with the Secretary of the Interior. In order to qualify for a grant, a tribe would have to demonstrate that its proposal would be the most efficient, cost-effective method for providing electricity to serve tribal needs. Grants for physical infrastructure facilities could be limited to not more than 50 percent of the cost of proposed facilities.

Finally, DOE recommends that tribes be encouraged to participate as new entrants in competitive electricity markets. Tribes would be eligible for an investment tax credit if they build generating plants and other facilities that are used for sales to non-tribal customers.

Issue 2. WORKER DISPLACEMENT – How can the federal government help alleviate worker displacement associated with the implementation of retail competition?

Recommendation: (1) Amend the Administration bill to allow state worker displacement programs to be eligible for matching grants from the Public Benefits Fund; and (2) Establish a program administered by the Department of Energy to retrain industry workers.

Some have expressed concern that, during the transition to retail competition, some workers may be displaced as the traditional vertically integrated utilities downsize to adapt to the changing market. While competition will provide overall benefits to the economy and the labor force, some programs might be necessary to ease the burden on displaced workers.

The Administration's Plan proposes to establish a fee on all electricity sales which would be used for a Public Benefits Fund to provide matching grants to the states for various public purpose programs. Some have suggested, and DOE recommends, that state worker displacement programs also be made eligible for matching grants from the Public Benefits Fund. In addition, we recommend that DOE be authorized to create a retraining program to help industry workers gain new tools to meet the challenges of a competitive electric utility industry.

Issue 3. GENERATING PLANT EFFICIENCY – How can DOE monitor the improvement of the efficiency of new and existing generating plants?

Recommendation: Direct the Department of Energy to conduct a study and prepare a report regarding the impact of competition in improving the efficiency of new and existing generating plants.

The Administration bill would require DOE to study the impacts of wholesale and retail competition. The collection of this information would be critical to an examination of whether customers are receiving the economic benefits of an efficient competitive market and whether suppliers are operating and planning efficiently in those markets.

It is also important to examine the success of competitive markets in improving the efficiency of new and existing generating plants. Through increased power plant efficiency, lesser amounts of fuel will be necessary to generate the same amount of electricity. Both consumers and the environment would benefit because increased efficiency will lower electric prices and reduce the emission of greenhouse gases as well as other pollutants. Because of the importance of increasing efficiency for the success of competitive markets, DOE recommends that it be tasked with studying the extent of efficiency improvement in competitive markets.

Issue 4. CLARIFYING STATE AUTHORITY TO REQUIRE NET METERING – Should the net metering provision in the Administration's bill include a provision clarifying that states have the authority to require a retail supplier to offer net metering services?

Recommendation: Clarify state authority to require that retail suppliers offer net metering services to any customer that requests such services.

The Administration's bill includes a provision requiring that all retail electric suppliers make net metering service available to any customer that requests such service. Under net metering, a single meter monitors the net amount of electricity generated either for use by the customer or for the benefit of the grid.

MidAmerican Energy Corporation, an investor-owned utility, has recently filed a petition with the Federal Energy Regulatory Commission challenging Iowa's imposition of a net billing requirement. MidAmerican claims that PURPA preempts the Iowa commission from requiring net billing, which has the effect of requiring MidAmerican to pay rates substantially in excess of its avoided cost for such purchases if the facility were a qualifying facility under PURPA. In addition, MidAmerican argues that the Federal Power Act preempts state commission action, because sales from a net metering facility would constitute sales of power at wholesale in interstate commerce.

While the Administration's net metering provision provides that all customers are entitled to net metering service, there is at least a question as to whether a state has the ability to impose its own net metering requirement. To clarify that states have the authority to impose net metering requirements, the net metering provision in the Administration's bill should be amended to provide that neither PURPA nor the Federal Power Act preempts a state from imposing a net metering requirement.

Issue 5. ISO PLANNING AUTHORITY AND RELIABILITY RESPONSIBILITY –

Should the Independent System Operator Provision be amended to provide that the ISO have planning authority and reliability responsibility?

Recommendation: Amend the ISO provision to provide that the ISO should have planning authority and reliability responsibility.

In the Administration's bill, FERC is given the authority to establish and require independent system operation if the entity is established for the purpose of independent operation and control of interconnected transmission facilities. In the Final Report of the Task Force on Electric System Reliability, the Task Force recommended that an ISO should conduct planning for the bulk power system. In addition, the Task Force recommended that the ISO should be responsible for maintaining the reliability of the region in accordance with established reliability standards. DOE agrees that an ISO should have these responsibilities and accordingly recommends that the ISO provision be amended consistent with the above recommendation.

Issue 6. TREATMENT OF ALASKA AND HAWAII -- Should Alaska and Hawaii be treated any differently because they are not connected to the electric grid in the continental United States?

Recommendation: Exempt Alaska and Hawaii from the bill's requirements related to competition.

Wholesale and retail competition is made possible by the fact that the vast majority of consumers and electric generating plants are interconnected. However, Alaska and Hawaii are not connected to the grid in the continental United States. DOE recommends that Alaska and Hawaii be exempted from the provisions of the Comprehensive Electricity Competition Act that are directly predicated on the ability of consumers and marketers to benefit from grid interconnections, including the requirements directly related to retail and wholesale competition.

Issue 7. FERC ENFORCEMENT – Should civil penalties be expanded to remedy industry violations of the Federal Power Act?

Recommendation: Expand the applicability of civil penalties to cover violations under Part II of the Federal Power Act.

Section 316A of the Federal Power Act authorizes civil penalties for violations of sections 211-214 of the Act or rules or orders issued under those sections. FERC should have the tools necessary to effectively enforce existing and proposed consumer protection and reliability requirements under the Act. The applicability of the currently available civil penalties – up to $10,000 per day – should be expanded to cover violation of any of Part II's regulatory regime.