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Report to the Chairman, Subcommittee on Water and Power, Committee on Resources, House of Representatives

March 2000

POWER MARKETING ADMINISTRATIONS

Their Ratesetting Practices Compared With Those of Nonfederal Utilities

GAO

Accountability * Integrity * Reliability

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Contents

Abbreviations

CVP	Central Valley Project
CWIP	construction-work-in-progress
DOE	Department of Energy
EIA	Energy Information Administration
EPAct	Energy Policy Act of 1992
FERC	Federal Energy Regulatory Commission
GA-AL-SC	Georgia-Alabama-South Carolina
IOU	investor-owned utility
mWh	megawatthour
O&M	operating and maintenance
PMA	power marketing administration
POG	publicly owned generating utility
PRS	power repayment study
PUC	public utility commission
RRS	revenue requirement study
SCLA-IP	Salt Lake City Area Integrated Projects

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Accountability * Integrity * Reliability

United States General Accounting Office
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Accounting and Information
Management Division

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March 30, 2000

The Honorable John T. Doolittle
Chairman, Subcommittee on Water and Power
Committee on Resources
House of Representatives

Dear Mr. Chairman:

This report responds to your request that we review the ratesetting practices of the Department of Energy's (DOE) power marketing administrations (PMA) and compare them with those of other utilities. As a follow-on to our previous work, which discussed the PMAs' ability to defer recovering through rates some of the federal government's investment in power facilities, you asked that we examine the PMAs' ratesetting practices and assess their impact on the PMAs' future competitiveness. Specifically, you asked us to determine

1. how the PMAs set their rates to recover costs,

2. how the PMAs' ratesetting practices compare to those of investor-owned and publicly owned utilities, and

3. the impact of the PMAs' ability to defer repayment of portions of their debt on their future competitiveness.

We evaluated the assumptions and processes the PMAs use in setting their rates and recovering their costs by collecting key data and analyzing methodologies at the four PMAs,[1] DOE, and the Federal Energy Regulatory Commission (FERC) as well as three investor-owned utilities (IOU) and four publicly owned generating utilities (POG).[2] We also compared the PMAs' financial data to IOU and POG financial data obtained from the Energy Information Administration (EIA).[3] We conducted our review from June 1999 through March 2000 in accordance with generally accepted government auditing standards. Additional information on our objectives, scope, and methodology is contained in appendix I.

Results in Brief

The PMAs determine the adequacy of rates by performing annual reviews of their projected costs and revenues,[4] using processes and assumptions that are to identify and factor into rates costs that are legally recoverable, while keeping rates as low as possible. Southwestern, Southeastern, and most Western projects make this determination through power repayment studies (PRS); Bonneville uses a revenue requirement study (RRS). These studies analyze historical data and project estimated future costs and revenues as a key part of ratesetting. The primary goal of the review is to determine whether existing rates will generate sufficient revenue to recover identified costs over the period under review. The PMAs are to take action to remedy the situation when the projections indicate that this cost recovery goal is not being met. Any consideration of a rate change prompts a public process during which customers and the general public are able to provide input before the change is finalized and approved by FERC.

[1]The four PMAs are Bonneville Power Administration (Bonneville), Southeastern Power Administration (Southeastern), Southwestern Power Administration (Southwestern), and Western Area Power Administration (Western). Because of differences in legislative authority and ratesetting practices, in this report we sometimes discuss Bonneville separately and refer to the other PMAs as "the three PMAs."

[2]See appendix I for a further discussion of our selection criteria for IOUs and POGs.

[3]EIA is a statistical and analytical agency in the Department of Energy.

[4]The three PMAs' rates are based on cash flow projections of the revenue required to recover costs. Bonneville's revenue requirements are set at the higher of forecasted accrued expenses (including depreciation expense) or cash requirements. Revenue generated in any given year is used to repay annual expenditures of the year, such as operating and maintenance costs, interest costs, and the cost of power purchased from other utilities for resale. Any revenue remaining after payment of such annual expenditures is allocated to repay appropriated debt.

Although there are similarities between the PMAs' ratesetting practices and those of IOUs and POGs, there are some key differences. Regulatory oversight and the processes and assumptions that guide cost recovery vary among PMAs, IOUs, and POGs. In addition, rates are affected by responsibilities to investors and/or taxing authorities and whether the entity operates in a cost-based or market-based environment. All the entities we reviewed had some kind of public process that took place when changes in rates were under consideration. However, PMAs differed significantly from IOUs and POGs in two areas. First, they have the flexibility to defer repayment of appropriated debt[5] until the year due, which is typically longer than other utilities are able to defer repayment of their debts.[6] Second, unlike IOUs and POGs, PMAs do not have to generate a return for owners[7] and generally do not pay taxes.

While PMAs have the flexibility to defer repayment of appropriated debt until the year due, in practice they have repaid significant portions before due and generally retire high interest rate debt first. Nevertheless, the financing costs as a percentage of operating revenues of three of the PMAs—Bonneville, Southeastern, and Western—are high relative to IOUs and POGs. Bonneville's financing costs are relatively high because of its large interest-bearing debt of about $13.8 billion, of which $4.2 billion relates to nonoperational and canceled nuclear facilities. Southeastern's and Western's financing costs are relatively high because of capital expenditures made in recent years, some at relatively high interest rates, much of which has not yet been repaid. These high financing costs may become more significant in an increasingly competitive electricity industry. While the high financing costs will pose challenges for these three PMAs,

[5]We call this appropriated debt because PMAs are required to set rates to repay appropriations used for capital investments with interest. However, these reimbursable appropriations are not technically considered lending by Treasury. The PMAs in some cases receive financing through means other than appropriations. For example, Bonneville issues bonds to the U.S. Treasury and Western receives nonfederal (third party) financing at certain projects.

[6]Due dates for appropriated debt vary. In general, appropriated debt related to (1) original construction of assets used to generate power must be paid within 50 years, (2) assets used to transmit power must be paid within 35 to 45 years, and (3) replacements of assets that generate or transmit power must be paid within 50 years or their useful service lives, whichever is less.

[7]IOUs are typically expected to generate a return for shareholders, and some POGs transfer funds from accumulated net revenues to other government units to fund other government activities.

all of the PMAs have important cost advantages that enhance their competitive positions as industry restructuring proceeds and other utilities attempt to cut costs and become more efficient. Key among the PMAs' advantages is that they market low-cost hydropower, much of it generated from facilities built decades ago at low cost. In addition, in contrast to IOUs and POGs, PMAs are generally not required to pay taxes or generate a return for owners. Because of these inherent cost advantages, the PMAs overall are well positioned competitively.

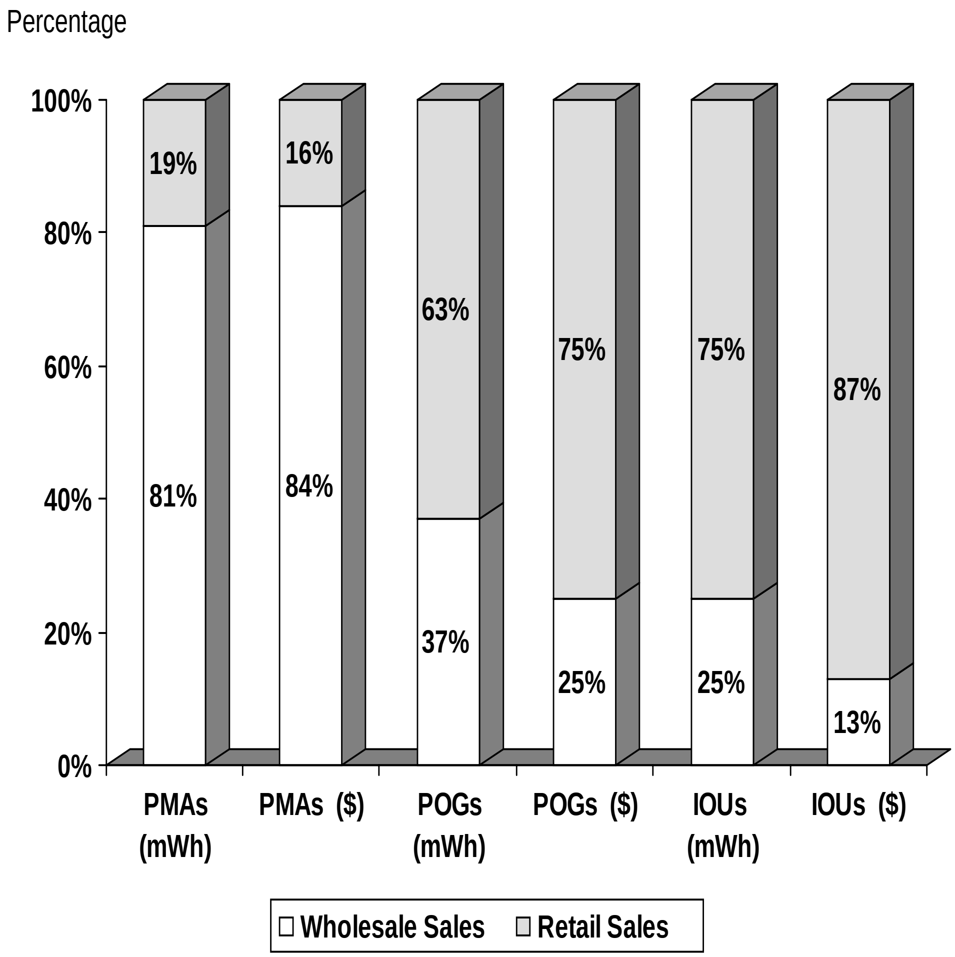
Background

The PMAs were established between 1937 and 1977 to sell and transmit electricity generated primarily from federal hydropower facilities. The facilities were constructed as part of a larger effort to develop multipurpose water projects that have functions in addition to power generation, such as navigation, flood control, irrigation, water supply, and recreation. Most of these facilities were constructed, and continue to be owned and operated, by the Department of the Interior's Bureau of Reclamation and the U.S. Army Corps of Engineers. As required by law, the PMAs give preference in the sale of power to public power customers such as irrigation districts, municipally owned utilities, customer-owned cooperatives, and, in some cases, state governments and the federal government.

The electricity industry encompasses both wholesale and retail markets. Wholesale power sales are sales by one entity to another for resale to ultimate consumers. Retail power sales are sales to residential, commercial, industrial, and other end-use consumers. According to EIA, about one half of all electricity generated in the United States is traded in the wholesale market before being sold to the ultimate consumer.

The PMAs sell power primarily in the wholesale power market. In contrast, IOUs and POGs sell mostly retail power. Figure 1 shows the percentages of retail and wholesale power sales for the PMAs, POGs, and IOUs for 1998.

Figure 1: Percentages of Retail and Wholesale Power Sales for PMAs, POGs, and IOUs for 1998, in Megawatthours (mWh) and Dollars



Source: Developed by GAO based on data from the PMAs' annual reports and composite national data on IOUs and POGs from EIA.

The PMAs operate in an electricity industry that is changing from a highly regulated environment, in which cost is the main factor in determining rates, to one that increasingly relies on competitive markets to set prices. The implementation of the Energy Policy Act of 1992 (EPAct) and initiatives to promote retail competition in a growing number of states are creating greater competition in the industry. EPAct authorized FERC[8] to order public utilities to provide transmission, or "wheeling,"[9] services to promote competitive wholesale power sales. Before the passage of EPAct, FERC could not require utilities to provide wheeling services to promote wholesale power sales.

Pursuant to its authority under the EPAct, in 1996 FERC issued Order 888, which required utilities to offer wheeling services to other utilities or electricity providers at the same price and availability that they give themselves. This promotes competition by allowing generators to make sales for resale (e.g., wholesale sales) to noncontiguous utilities. Order 888 also allows recovery from customers of prudently incurred stranded costs[10] by utilities transitioning into a competitive marketplace. Recovery of wholesale stranded costs is regulated by FERC. Recovery of retail stranded costs is regulated at the state level, and implementation varies by state.

In addition, legislatures and public utility commissions in most states are considering, or have approved, initiatives that will promote competition in the market for retail power sales. As of February 1, 2000, 24 states had enacted legislation or regulatory orders promoting retail access to competitive markets; the remaining states and the District of Columbia were either actively pursuing restructuring or investigating restructuring options.

[8]FERC is an independent agency within the Department of Energy with broad regulatory authority over the interstate transmission and sale of wholesale electricity, natural gas, and oil.

[9]Wheeling is the transmission of power over lines owned by another utility.

[10]As defined by FERC, a stranded cost is any legitimate, prudent, and verifiable cost incurred by a public or transmitting utility that is no longer economically viable in a competitive environment.

PMA Ratesetting Practices

The PMAs' ratesetting practices (i.e., the processes and assumptions used in ratesetting) are expected to identify and factor into rates all costs that are legally recoverable from power customers while keeping rates as low as possible.[11] The PMAs receive their authority to set cost-based rates from the Reclamation Project Act of 1939 and the Flood Control Act of 1944. In addition, the primary statute governing Bonneville's ratesetting process is the Northwest Power Act. DOE's ratesetting practices for the PMAs have been established by the Secretary of Energy in Order RA 6120.2.[12] Each PMA performs an annual analysis to identify revenue requirements[13] for, in general, a 50-year period.[14] In doing so, each PMA costs to be recovered and levels those costs over the ratesetting period so as to keep rates low and stable. Rates are then set to recover costs.

[11]Previous GAO reports (*Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities* (GAO/AIMD-96-145, September 19, 1996); *Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses,* volumes 1 and 2 (GAO/AIMD-97-110 and 110A, September 19, 1997); and *Power Marketing Administrations: Repayment of Power Costs Needs Closer Monitoring* (GAO/AIMD-98-164, June 30, 1998)) have demonstrated that the PMAs are not recovering all costs of generating, transmitting, and marketing power.

[12]DOE Order RA 6120.2 on "Power Marketing Administration Financial Reporting" establishes requirements for a broad range of financial issues, including setting rates, recovering costs, preparing repayment studies, establishing and maintaining the accounting systems, and financial reporting.

[13]Revenue requirements are the revenues that must be generated to repay costs and debt and irrigation payments due in the applicable time period. In addition, Bonneville includes in its revenue requirements an annual reserve amount to mitigate the risk of not achieving repayment obligations.

[14]The period covered by the PRSs is longer than 50 years for some projects. For example, the PRSs cover 60 years for the Salt Lake City Area—Integrated Projects and 100 years for the Pick-Sloan project. It can also be shorter than 50 years if the appropriated debt related to assets used to generate and transmit power is paid off earlier. As discussed later, there can be a difference between the repayment period and the ratesetting period.

Identifying Revenue Requirements

PMAs are required to establish power rates sufficient to pay annual expenditures, such as operating and maintenance costs, interest costs, and the cost of power purchased from other utilities for resale. Rates must also be sufficient to repay debt, including the appropriations that financed completed generation and transmission facilities.[15] In addition, rates must be sufficient to repay certain nonpower costs the Congress has assigned to power users to repay. Bonneville's and Western's rates are set to collect additional revenue to repay the federal appropriations that financed certain irrigation facilities.[16] In addition, Bonneville is required to provide power to specified residential and small farm consumers of IOUs.

In addition to the above, Bonneville's rates must cover the costs of

- bonds issued to the Treasury to finance capital programs, such as transmission system development, conservation, and fish and wildlife enhancement;
- debt service on nonfederal bonds primarily for the construction of Energy Northwest (formerly the Washington Public Power Supply System) nuclear plants;[17] and

[15]In a limited number of cases, the capital costs of some completed projects are not included in rates. For example, as discussed later, certain construction costs and capitalized interest at the Richard B. Russell Project are not included in Southeastern's rates. Other costs that are sometimes not recovered from rates include certain environmental mitigation costs that have been legislatively exempted from recovery.

[16]Reclamation law provides for Bonneville and Western to use their power revenues to repay a portion of the capital costs allocated to completed irrigation facilities that are determined by the Secretary of the Interior to be beyond the ability of the irrigators to repay. As of September 30, 1998, approximately $863 million in irrigation costs had been allocated for repayment through power revenues at Bonneville and $3,139 million at Western. Of those amounts, $25 million (3 percent) had been repaid at Bonneville and $35 million (1 percent) repaid at Western.

[17]Bonneville used its contracting authority to acquire all or part of the generating capability of nuclear power projects in Energy Northwest. Under these contracts, Bonneville agreed to pay all or part of the annual projects' budgets, including debt service, whether or not the projects are completed. Two of the nuclear plants are nonoperational and therefore do not generate revenues. As of September 30, 1998, Bonneville had $6.9 billion outstanding in nonfederal project debt.

- measures to protect fish and wildlife populations and to mitigate damage to Pacific Northwest fish stocks affected by the construction and operation of the Federal Columbia River Power System.[18]

DOE Order RA 6120.2 requires that the PMAs annually determine the adequacy of power rates by calculating how much revenue is needed each year to meet annual expenditures and debt repayment requirements over the ratesetting period. The three PMAs make this determination through power repayment studies (PRS). Bonneville uses a revenue requirement study (RRS), which is similar to a PRS. Bonneville considers several risks in developing its revenue requirements. Among the risks considered are weather-related uncertainties associated with the reliance on hydropower generation, market prices for power, general economic conditions, the performance of its generation assets, and expenditures Bonneville must make to protect, mitigate, and enhance fish and wildlife populations. Bonneville's target is to set rates that will result in a 97.5 percent probability that payments to the Treasury will be made on time and in full for each year of the rate period (or 88 percent over a 5-year period). Once Bonneville establishes its revenue requirements, it allocates costs to classes of service and designs rates.

PMAs prepare these studies on either a project basis or a system basis, consistent with how they sell power and set rates. For example, Southeastern sells power within four separate power systems; each includes one or more Corps projects for which rates are set. Bonneville's RRS includes all of its power projects. However, Bonneville is required by 26 FERC 61,096 to separately develop transmission rates.

A PMA's PRS or RRS determines its annual revenue requirements by analyzing historical financial information and projected estimates of future revenues, expenditures, and capital costs throughout the period covered by the study. Historical financial information is gathered from the accounting records. In addition, historical, and projected generation, hydrological and other data are provided by project operators (i.e., the Bureau and the Corps).

[18]Bonneville's estimated range of funding is $438 million to $721 million annually for fiscal years 2002 through 2006.

When preparing a PRS or RRS, the PMAs make several assumptions about the future in establishing revenue requirements and setting rates. Key assumptions include the following:

- Historical hydrological data and projected river operations will be used to project future water conditions.
- Appropriated debt related to the original construction of assets used to generate power will generally be repaid within 50 years.[19]
- Appropriated debt related to assets used to transmit power will generally be repaid within 35 to 45 years.
- Appropriated debt related to replacements of assets used in generating and transmitting power will be repaid within the lesser of 50 years or their estimated useful service lives.
- The PRS/RRS will include a "cost evaluation period," which usually is the first 5 years of the PRS/RRS.[20] During the cost evaluation period, future estimates of costs and revenues, which are based on forecasted budget data, may be modified to reflect changing conditions, such as additions to the power systems or inflation. Operating and maintenance (O&M) cost estimates are escalated by an inflation factor over the 5-year period, and the estimate for the fifth year is then carried through to the end of the ratesetting period without further escalation.[21]
- Interest rates in effect for each project will be those specified in the individual project authorizing legislation, or in DOE Order RA 6120.2 for all future year investments.
- Where possible, to mitigate interest costs, the highest interest rate debt will be paid first.
- The PMAs will take a credit against interest costs to recognize the savings to the government for payments the PMAs make to the Treasury throughout the year for obligations that are not due until the end of the year.

[19]There are exceptions, such as Bonneville's Yakima-Chandler Project with a legislated repayment period of 66 years.

[20]However, the length of the cost evaluation period is discretionary and is not always 5 years. For example, in its fiscal year 2002 Initial Power Rate Proposal, Bonneville uses an 8-year cost evaluation period (fiscal years 1999 through 2006). The cost evaluation period extends from the last year historical information is available (fiscal year 1998) through the proposed 5 year rate test period (fiscal years 2002-2006), which is the period rates are expected to remain in effect.

[21]Southeastern's cost estimates are escalated by an inflation factor to the mid-point of the evaluation period. These estimates are then carried through to the end of the rate review period with no further escalation.

In addition to the above, Bonneville makes the following key assumptions:

- U.S. Treasury bonds will be systematically repaid based on the term of the debt.
- Revenue requirements will be set at the higher of forecasted accrued expenses (including depreciation expense) or cash requirements.
- Rates will be developed so as to create an 88 percent probability that cash flows will be sufficient to enable Bonneville to make Treasury payments on time and in full over a 5-year period. Bonneville analyzes operating (e.g., hydro generation) and nonoperating risks (e.g., fish and wildlife expenses) and risk mitigation measures in assessing whether the 88 percent probability is met.
- Financial reserves will be maintained to mitigate risk. For example, Bonneville includes as a component of its revenue requirement, amounts to mitigate risks associated with several factors, including funding of fish and wildlife initiatives, water conditions, and economic conditions.

As mentioned previously, under DOE Order RA 6120.2, the PMAs are required to set rates sufficient to recover costs. The PMAs generally use PRSs and RRSs as a basis for setting rates and keeping rates as low and stable as possible, even though revenue requirements vary from year to year. For example, a ratesetting system may have 43 years of comparatively stable revenue requirements, but a large increment of appropriated debt becomes due in year 44 of the ratesetting period. The PMAs attempt to level payments over the entire ratesetting period.

Unless otherwise prescribed by project enacting legislation or DOE regulation, the PMAs are generally allowed to defer the repayment of appropriated debt until it is due, generally 50 years for original construction of projects and additions to projects, 35 to 45 years for transmission assets, and the lesser of 50 years or the estimated service lives for replacements. These provisions give the PMAs some flexibility, within the parameters of DOE Order RA 6120.2, in determining when to repay appropriated debt.[22] In practice, after paying annual costs that are required to be paid in any given year, the PMAs then generally use any remaining revenues to repay highest interest rate debt.[23] The PMAs have flexibility in selecting which increment of debt to repay among those bearing the same interest rate.

Although all the PMAs use allowable repayment periods as noted above, there are some differences in their interpretations of DOE Order 6120.2 regarding the ratesetting period. For example, Southwestern considers the ratesetting period to be 50 years. Southeastern considers the ratesetting period to be 50 years from the date of the last increment of appropriated debt that would require a rate adjustment; therefore, if no additional significant appropriated debt is incurred, the ratesetting period decreases each year. Some Western projects consider the ratesetting period to be the period up to the pinch-point year, discussed below, or when the last increment of appropriated debt is repaid, whichever is later.

[22]According to DOE Order RA 6120.2, the order of precedence for repayment each year is annual expenditures (O&M, purchased and exchange power, and transmission service), interest costs, unpaid or deferred annual expenditures, if any, and any debt due in that year. Remaining revenues are available for repayment of appropriated debt. In addition, Public Law No. 89-448 authorized the payment of irrigation costs from remaining revenues. Costs incurred in any year in which revenues fail to recover annual expenditures are deferred to the following year and accrued on the balance sheet as a liability. Deferred costs are repaid with interest.

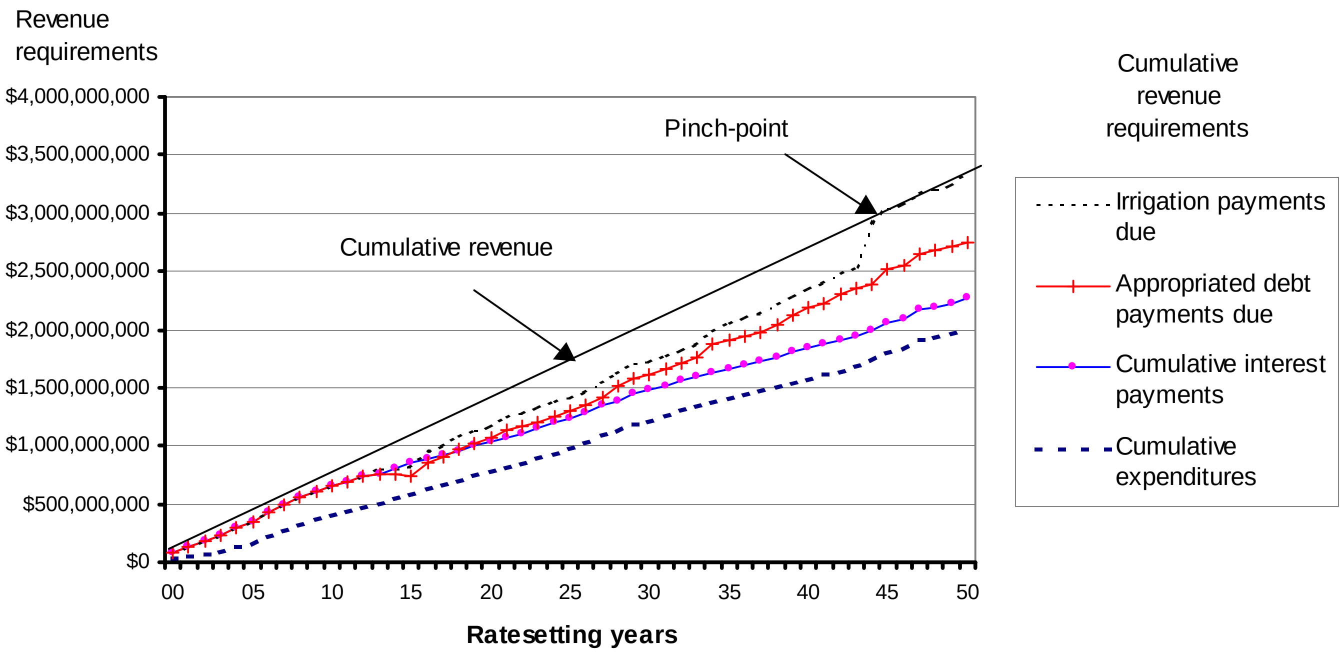
[23]Debt that is due in a given year—including low interest debt and irrigation debt that carries no interest—is a higher priority for repayment than higher interest rate debt.

The PMAs' rates are generally set based on the projected cumulative revenue requirements through a time frame ending with what is referred to as the "pinch-point" year.[24] The pinch-point year is the year within the period covered by the PRS in which the annual revenue requirements are projected to be the highest. Rates are set to ensure that the cumulative revenue for the first year of the study through the end of the pinch-point year is at least equal to the cumulative revenue requirements for the same period. The pinch-point year occurs when a significant required payment is due for annual expenditures and/or a capital repayment obligation.[25] Figure 2 illustrates that cumulative revenue and cumulative revenue requirements must be equal by the pinch-point year.

[24]Rather than "pinch-point," Bonneville uses the term "critical year." The "critical year" is the year where Bonneville's levelization of debt service is at the point where each obligation is scheduled for repayment by no later than its due date.

[25]These expenditures that must be made in the pinch-point year arise because (1) annual expenditures are generally required to be paid in the year incurred, although certain expenditures can be deferred in years when revenues are insufficient to cover them, (2) the repayment of some debt cannot be further deferred because they are at their due dates, (3) the amount of revenue the PMAs can generate each year is limited and therefore the PMAs cannot wait until the years that the debt is due to repay it, and (4) some lower interest debt cannot be paid earlier because cash available to repay debt will be used to repay higher interest rate debt first under DOE Order RA 6120.2's repayment precedence. Only significant changes in these factors, such as large additions or replacements that would affect revenue requirements, would move the pinch-point year.

Figure 2: Illustrative Pinch-Point Year for a PMA Ratesetting System



Source: Developed from information provided by the PMAs, particularly the Western Area Power Administration.

In this example, cumulative revenue meets cumulative revenue requirements in year 44 of the ratesetting period, the pinch-point year. Under DOE Order RA 6120.2, the PMAs are to take action if the current rate will not generate sufficient cumulative revenue to equal cumulative revenue requirements by the pinch-point year. Such action may include cutting costs and/or adjusting rates. As illustrated by figure 2, cumulative revenues exceed cumulative revenue requirements prior to the pinch-point year. During this ratesetting period, early repayments of appropriated debt due in the pinch-point year facilitate meeting total cumulative revenue requirements by lowering the amount due in the pinch-point year. This allows a single rate to generate sufficient revenue to recover cumulative costs by the pinch-point year. Beyond the pinch-point year, the cumulative revenues exceed the cumulative revenue requirements and rates would be recalculated.

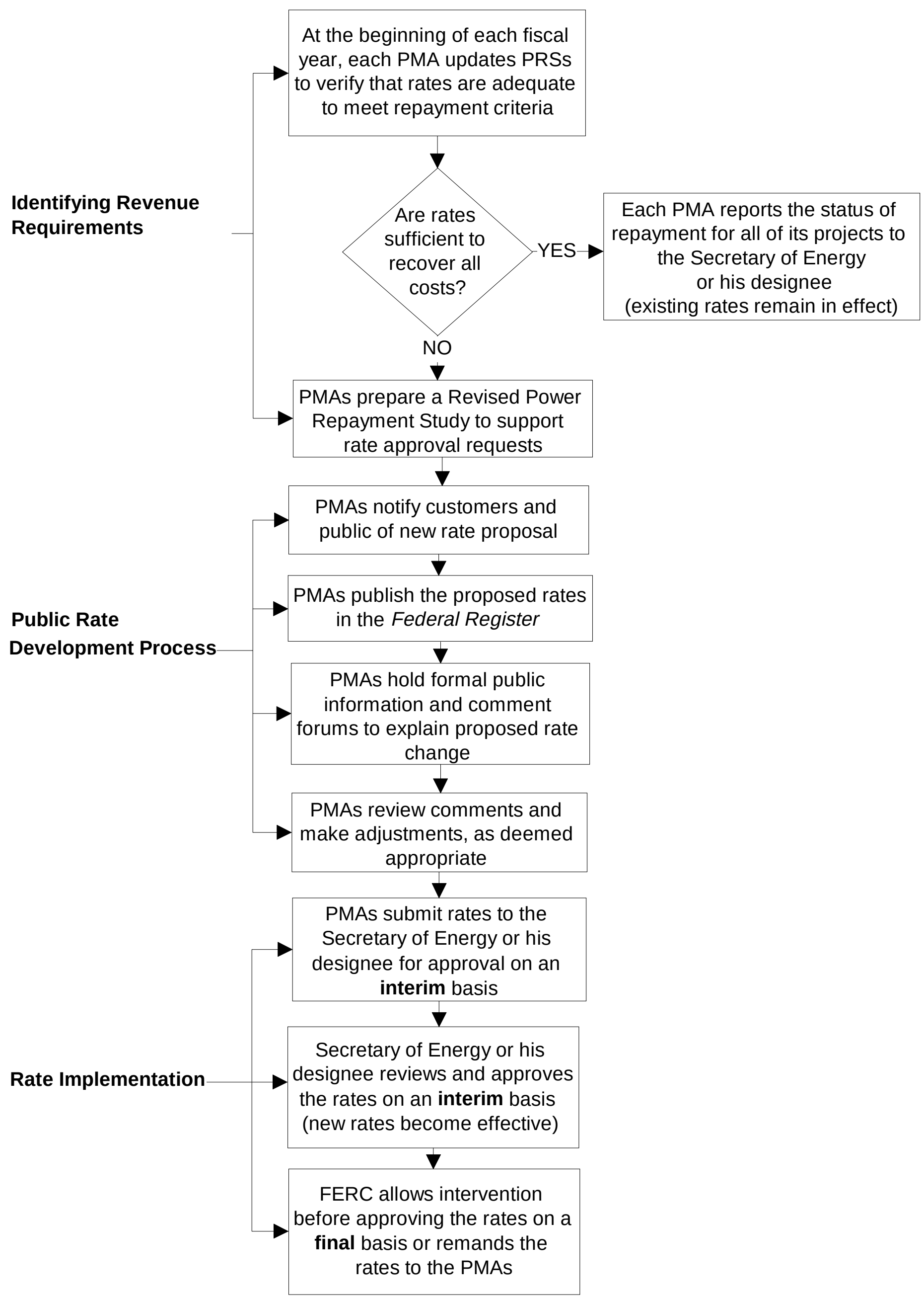
PMAs Use Open Public Process in Developing Rates

When they are considering a rate adjustment, the three PMAs are required to publish notices in the *Federal Register* to notify customers, the general public, and other interested parties. The three PMAs then have 90 days from the date of the *Federal Register* notice to conduct public information and public comment forums, which are transcribed formal events in which the three PMAs explain the procedures used to establish and support the rate adjustments and provide citizens the opportunity to voice their opinions and suggestions. All comments are considered during the rate development process. If this public participation process leads to significant changes in the proposed rate adjustment, a modified proposal may be published in the *Federal Register* and the public again offered an opportunity to comment on the modifications.

The three PMAs prepare a final rate proposal for each ratesetting system and forward the information to the Secretary of Energy or his designee, requesting the Secretary to confirm, approve, and place the rate into effect on an interim basis. Once this approval takes place and the interim rate is placed into effect, the Secretary submits the rate proposal to FERC for final approval. After reviewing the rate proposal, FERC is authorized to take one of three actions, but does not have authority to change the rate. FERC may (1) confirm, approve, and place the rate into effect on a final basis, (2) send it back to the PMA for further study, or (3) disapprove it, in which case the rate that existed prior to the interim rate goes back into effect. Upon rendering its decision, FERC publishes a notice in the *Federal Register*.

The rate development process for the three PMAs is depicted in figure 3.

Figure 3: The Three PMAs' Rate Development Process



Like the three PMAs, Bonneville prepares its revenue requirement analysis[26] under DOE Order RA 6120.2 guidance and files a notice of the initial rate proposal in the *Federal Register*. Bonneville's ratesetting process is specified in the Northwest Power Act which, among other things, requires Bonneville to hold rate case proceedings in determining the final rate proposal.

Bonneville holds field hearings throughout the region to obtain public input and questions from all interested participants (e.g., consumers). The hearings are recorded and transcribed and become a part of the official record. In addition to field hearings, Bonneville holds formal hearings, which are semijudicial rate case proceedings. Both types of hearings are presided over by a hearing officer. However, only parties to the rate case[27] may take part in the formal hearings. Such parties file direct cases (testimony) including responding to Bonneville's initial rate proposal. Bonneville and the parties file rebuttal testimony to the parties' direct cases and have the opportunity to ask clarifying questions about one another's testimony and submit written data requests in order to prepare their responses. In addition, both Bonneville and parties to the rate case have an opportunity to cross-examine one another's witnesses on all relevant issues.

At the close of the formal hearings, the parties prepare initial briefs summarizing their issues to date.[28] Bonneville's Administrator reviews the official record and prepares a draft Record of Decision. Parties to the rate case may respond to the draft Record of Decision by filing "Briefs on Exceptions," by a specified date (usually within a month).[29] The administrator reviews the entire record and issues a final Record of Decision. Unlike the three PMAs, Bonneville is not required to submit its

[26]When considering a rate adjustment, Bonneville's planned expenses and capital investments for the rate period are made subject to public review and comment before a rate proposal is initiated.

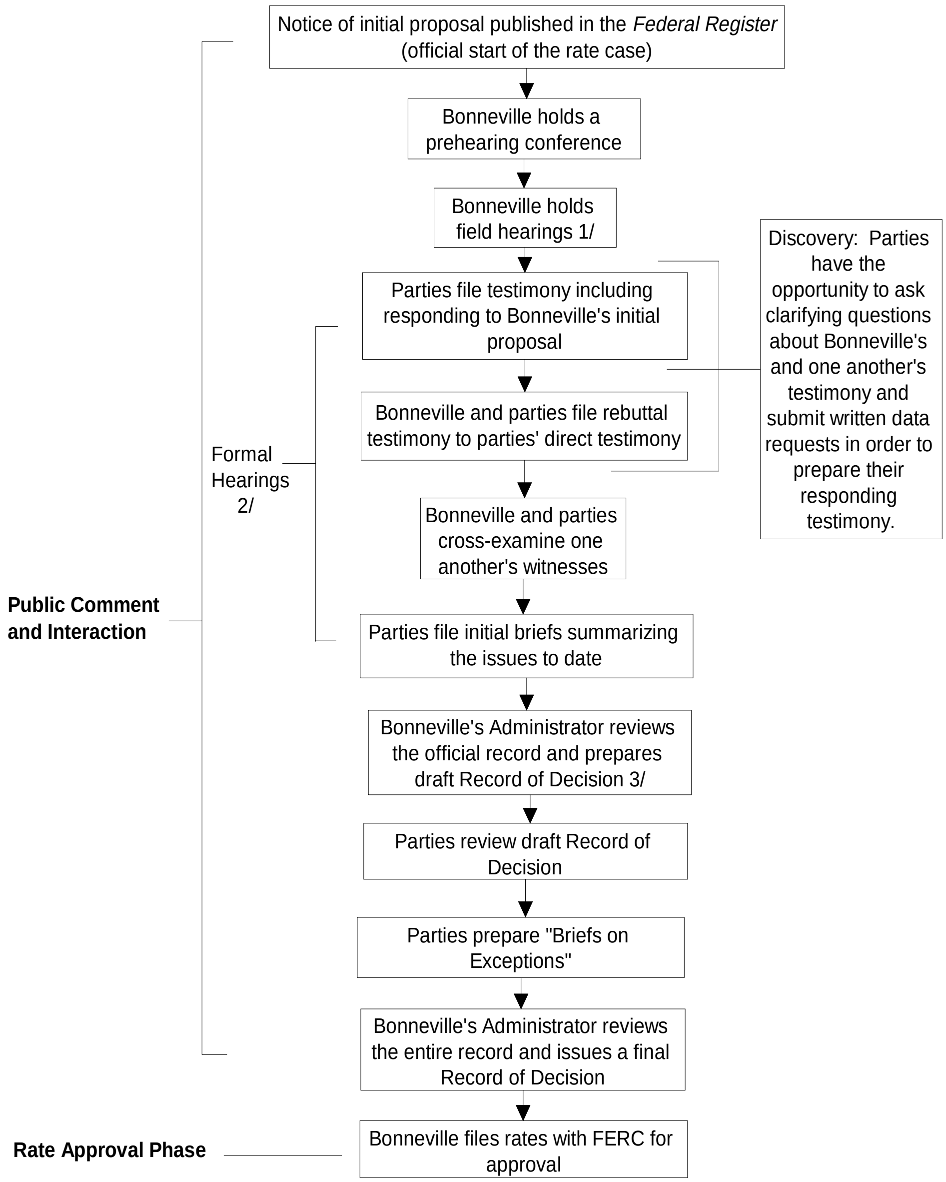
[27]Parties to the rate case are those individuals or groups designated by the hearing officer as parties. Interested individuals or groups must submit a "petition to intervene" for consideration to become parties.

[28]The purpose of an initial brief is to identify separately each legal, factual, and policy issue to be resolved by the Administrator.

[29]The purpose of the briefs on exceptions is to (1) raise any alleged legal, policy, or evidentiary errors in the draft Record of Decision and (2) provide additional support for tentative decisions contained in the draft Record of Decision.

rate proposal to the Secretary of Energy. The proposed rates are submitted directly to FERC for approval. FERC's approval process for Bonneville is the same as for the other three PMAs. The rate development process for Bonneville is depicted in figure 4.

Figure 4: Bonneville's Rate Development Process



1/ The rate case is open to the public; comments become part of the official record.

2/ Some of the field hearings are held concurrently with the formal hearings. Only "parties" to the rate case may take part in the formal hearings. The hearing officer determines "parties" to the rate case.

3/ Official record includes testimony, exhibits, hearing transcriptions, letters and other documents filed during the rate case.

Ratesetting Practices of the PMAs, IOUs, and POGs Differ

Like PMAs, IOUs[30] and POGs gather data and prepare studies to determine the revenue requirements necessary to recover their costs, obtain input from interested parties at public forums, and present rate proposals to the appropriate oversight body. However, the processes and assumptions used by IOUs and POGs differ from those of the PMAs in several respects. Key differences relate to

1. cost recovery and the process for setting rates, including oversight procedures,

2. whether rates are cost-based or market-based, and

3. the responsibilities to owners or taxing authorities.

Cost Recovery Practices and Ratesetting Processes

In general, PMAs recover their costs through wholesale rates while IOUs and POGs recover costs through a combination of retail and wholesale rates. In both regulated and restructured states, the market generally sets IOUs' and POGs' wholesale generation rates. In a regulated environment, IOUs generally recover their fixed costs through their retail rates. As a result, excess power sold in wholesale markets generates a profit to the extent that prices set by the wholesale market exceed IOUs' marginal costs. As states restructure, IOUs will likely begin to recover more fixed costs through their wholesale rates because competitive pressures on retail rates will likely reduce the amount of fixed costs that IOUs can recover through retail sales. In general, POGs are owned and operated by the municipalities they serve and report to an elected or appointed local oversight body, such as a city council or utility governing board. In addition, in 12 states POGs are also subject to regulation by a state regulatory authority. As a result, POGs' ratesetting practices vary.

[30]For purposes of this discussion, we define an IOU as a for-profit utility that generates, transmits, and distributes power.

As noted earlier, the PMAs' PRSs/RRSs include information on historical costs from project inception and projected costs and revenues over the ratesetting period, generally 50 years. When setting rates, the PMAs factor projected inflation into their analyses during the first 5 years of the PRS, which is called the cost evaluation period. In contrast, in setting their retail rates IOUs use a much shorter period—a 1-year historical period—and generally project costs only from 0 to 2 years forward. Among the POGs, the number of historical years used in setting rates generally ranges from 1 to 3 years while the number of years used to project revenue requirements typically ranges from 3 to 5 years.[31] All of the POGs we contacted considered the impact of inflation and/or trends on their projections of future revenue requirements.

IOUs systematically recover their capital costs through rates by using annual depreciation or amortization,[32] either on a straight-line basis over the life of the asset or on an accelerated basis.[33] IOUs also pay financing costs, including interest on loans and bond interest, on a systematic annual basis. They typically repay debt financing obtained by issuing bonds or taking out loans in accordance with the terms of the bond and loan agreements.

POGs use depreciation and amortization expense to recognize capital costs for financial reporting purposes, but generally recover capital costs based on the debt service requirements included in their annual budgets. They

[31]For the POGs we contacted, the number of historical years used in setting rates ranged from 1 to 10 years, while the number of years used to project revenue requirements ranged from 3 to 25 years. However, POGs generally use revenue requirement projections beyond 5 years to make decisions about future expansion or to identify when they believe future rate adjustments or new bond issuances may be needed, rather than for immediate ratesetting purposes.

[32]Depreciation is the allocation of the expense associated with property, plant and equipment to each period benefited by the asset. Amortization is the allocation of expenses associated with intangible and other assets, such as abandoned plant, to each period benefited. Straight-line depreciation and amortization are calculated by dividing the cost of the asset less estimated salvage value, if any, by its estimated useful life or allowable period of time.

[33]Some IOUs are preparing for the move toward market-based rates by accelerating depreciation while their retail rates still remain protected. For example, some states that have restructured have frozen retail rates until a future set date. IOUs can use this opportunity to accelerate depreciation to recover as much of their investment as possible; then, when they make the transition to full market-based rates, they can stretch out recovery of their remaining capital costs to make their rates more competitive.

repay financing costs and principal in the same manner as IOUs. The financing period for capital assets and the period for recovering the cost of capital projects used by the POGs we contacted ranged up to 35 years. In contrast to IOUs and POGs, the PMAs have flexibility to repay their appropriated debt any time up to the year due, which is generally the 50th year for generation assets.

IOUs' Ratesetting Process

To set rates in a regulated environment,[34] IOUs identify the costs that must be recovered through rates, such as those related to O&M, transmission, purchased power, debt related to capital assets, interest on financed debt and/or bonds, and taxes. In identifying these costs, IOUs adjust for known events, such as salary increases and property tax increases. In addition, IOUs determine the total cost of assets that must be recovered through rates and are allowed to set rates to generate a regulated rate of return for investors on the value of these assets.

To determine expected revenues, IOUs take the total sales for all classes of customers for the prior year; in some cases, they recalculate these revenues to adjust them to a normalized weather year. They then make adjustments for known future events, such as a major new factory that would require a significant amount of power in the coming year. In general, IOUs use 1 year of historical data and project from 0 to 2 years into the future. They compile the data into a rate case, with proposed rates by class of customer (e.g., industrial, commercial, or residential) and submit the case to their state regulatory commission. Like the PMAs' rate proposals, the IOUs' rate proposals undergo a public process whereby interested parties can testify and introduce exhibits to support their positions. IOUs negotiate with their state commissions over the proposed rates, and the state commissions actually set the rates.

POGs' Ratesetting Process

POGs also prepare cost studies and evaluate their revenue requirements to identify the need for rate changes, give public notice of proposed rate changes, obtain input from interested parties at public forums, and present rate proposals to the appropriate oversight body for approval. However, we found significant differences among the POGs regarding the cost evaluation period used to identify revenue requirements and set rates, as illustrated by the following:

[34]In a restructured environment, the market sets the price for generation and only the distribution portion of an IOU's rates remains regulated.

- One POG sets its rates based on projected demand for power and expected costs for the following year only. Although it prepares long-term cost projections internally, these projections are used primarily to make decisions about future expansion and to identify opportunities to purchase power, and not for setting rates.
- A second POG analyzes costs over 5 to 10 years to set rates. Estimates of future power needs are generally projected 10 years, while cost of service analyses used to project future revenue requirements and set rates are generally projected over 5 years.
- A third POG projects its revenue requirements over 25-years and uses the 3-to-5 year projections to set rates. These projections are based on actual historical costs over the last 5 years and projected changes in the budget. The revenue requirement projections for years 6 through 25 are used primarily to identify the need for future rate adjustments or the issuance of new bonds. The projected costs for this period are based on various trend and regression analyses using historical data, the forecast data for years 1 through 5, and projected capital projects.
- The fourth POG does not follow a specific or formal process to set rates. The staff of its electric division makes recommendations to the city council to ensure that rates for the following year generate sufficient revenue to cover actual budgeted expenses plus a required payment in lieu of taxes to the city's general fund. Costs are generally not projected beyond the 1-year period.

POGs propose their own retail rates, which are generally reviewed and approved by the POGs' boards of commissioners or other local elected or appointed oversight body, such as a city council. In 12 states, the POGs are also subject to regulation by a state regulatory authority. Because POGs generally are not required to report to a specific regulatory body, we did not identify a consistent oversight and rate approval methodology applicable to them. For two of the POGs we contacted, the rates are set by the utility and approved by the city councils. For the other two POGs we contacted, the boards of directors approve all rate changes without the need for city council approval.

Cost-Based Versus Market-Based Ratesetting

As the electricity industry continues to move toward market-based rates, utilities are expected to find ways to become more efficient. In a regulated environment, IOUs' retail rates are based on the costs their state commissions allow in their rate bases, but in a competitive environment the IOUs' will have an incentive to reduce costs to enhance the competitiveness of their rates. The PMAs are also taking steps to reduce costs and prepare themselves for a competitive market situation, but they continue to set rates based on costs, as required by current law. Meanwhile, many of the larger POGs are increasingly abandoning their traditional fully allocated cost methods for designing rates and are focusing more on market conditions.

As noted, in a restructured environment the market generally sets the price for the generated commodity (power),[35, 36] FERC regulates transmission, and the state commissions set the rates for distribution (retail sales) for IOUs and some POGs. Local governing bodies generally set the rates for retail sales for most POGs. In most states this is the final approval process; however, in some states final approval is given by the state regulatory agency. Restructuring legislation varies from state to state and therefore differences exist among IOUs' ratesetting practices. However, several elements are similar among states that have restructured, and in general

- IOUs will continue to file rate cases for distribution services with their state commissions and where applicable, an IOU that provides default service[37] (from a cost-of-service perspective only) will also file a rate case with its state commission, and
- some states have frozen rates until a set future date, which should allow utilities an opportunity to recover potential stranded costs while rates are still protected.

Responsibilities to Investors and Taxing Authorities

IOUs are expected to generate a return for owners and pay income and other taxes. These costs are included in the IOUs' rate cases. POGs, as publicly owned utilities, typically do not pay income taxes because they are units of state or local governments. However, many POGs do make payments in lieu of taxes to local governments. In addition, in some cases POGs generate a return for owners in that the excess revenues they

[35]The market may not always set the price for power in a restructured state. For example, Oregon's restructuring legislation allows residential and small commercial customers who do not want to purchase power at market the option to continue to receive cost-of-service-based power.

[36]Depending on state restructuring legislation, some utilities are setting up marketing divisions to sell power. For example, one utility we spoke with sells power by phone on a short-term contract basis.

[37]Default service is the requirement for a provider to provide service for customers who do not choose an electricity supplier. State public utility commissions regulate default service.

generate are transferred from the POGs' accounts and used to fund other government activities. The PMAs do not have to generate a return for owners and generally do not pay taxes. The impact of these differences is discussed further in the next section.

Overall the PMAs Are Well Positioned Competitively

The PMAs are allowed to defer repayment of appropriated debt until due,[38] but in practice have been repaying significant portions before they are due and generally focusing on retiring high interest rate debt first. Nevertheless, the financing costs of three of the PMAs—Bonneville, Southeastern, and Western—are high relative to other utilities. While the high financing costs will pose challenges for these three PMAs, the PMAs overall have important cost advantages that enhance their competitive positions.

PMAs' Debt Repayment Practices

Under DOE Order RA 6120.2, the PMAs are not required to systematically (i.e., on a normal amortizing basis) recover from power customers the federal appropriations that finance the capital assets of projects at which the PMAs market power. Unlike traditional financing situations, such as home mortgages and bank loans, annual repayments of the PMAs' appropriated debt do not have to be made to the Treasury. Instead, the PMAs are required to recover the appropriated debt from power customers within a specified repayment period. The required recovery period is generally 50 years for assets used to generate power, 35 to 45 years for assets used to transmit power, and the lesser of 50 years or their estimated useful service lives for replacements.

While the PMAs have the ability to defer the repayment of the appropriated debt, in practice they have been repaying significant portions before the year in which they are due. Table 1 shows our analysis of the portions of the PMAs' debt that have been repaid before the year in which the debts are due. It shows the total percentages of debt repaid before the year in which the PMAs' debts are due and the percentages repaid at least 10 years before the year the debts are due for certain ratesetting systems.

[38]We are referring here to the PMAs' ability to put off into the future the repayment of certain low interest appropriated debt, while repaying high interest debt. We are not referring to the PMAs' ability to defer payment of annual operating and other expenses in years when revenues are insufficient to pay those costs.

Table 1: Percentages of the PMAs' Debt Repaid Before Due as of Fiscal Year-End 1998 (in Total and at Least 10 Years Before Due)[a]

	Bonneville		Southeastern[c,h]		Southwestern[c]	Western[c,d]	
	Appropriated Debt[b,c]	Treasury Bonds[g]	Cumberland	GA-AL-SC	Integrated[e]	CVP[f]	SLCA-IP
Total percentage repaid before year due	17	28	64	27	43	63.2	60.2
Percentage repaid at least 10 years before year due	9	24	36	25	19	62.7	59.7

[a]This analysis covered all Bonneville power projects (100% of 1998 power sales); Southeastern's Cumberland and Georgia-Alabama-South Carolina (GA-AL-SC) systems (89% of 1998 power sales); Southwestern's Integrated System (91% of 1998 generating capacity); and Western's Central Valley Project (CVP) and the Colorado River Storage Project of the Salt Lake City Area Integrated Projects (SCLA-IP) (47% of 1998 power sales).

[b]Bonneville's outstanding balance of appropriated debt was restructured as of October 1, 1996. The restructuring resulted in a reduction in the principal amount outstanding from about $6.9 billion to about $4.3 billion and an increase in the associated interest rate of about 3.6 percentage points. We do not consider the $2.6 billion principal reduction resulting from the restructuring to be a repayment.

[c]This analysis is of the repayment of appropriated debt related to assets already placed in service. It does not cover appropriated debt for assets not yet placed in service (e.g., construction-work-in-progress) because those assets do not have repayment due dates.

[d]The data needed to calculate these percentages for the Pick-Sloan project were not available.

[e]Southwestern's data is for fiscal year 1997. The actual percentage of appropriated debt for Southwestern's Integrated System that was repaid at least 10 years before the year due is higher. But, because of the way the repayment data are categorized in the PRS, in many cases we were unable to determine the exact year of the repayment.

[f]Although the repayment data for Western's CVP indicates the exact year of repayment of appropriated debt repaid in full as of September 30, 1998, it does not indicate the repayment year for appropriated debt that has been partially repaid. Therefore, repayment percentages are based on the status of repayment as of September 30, 1998.

[g]Bonneville has less flexibility in repaying bonds than in repaying appropriated debt. Although some of the debt is callable, the bonds are generally repaid based on the term of the debt (i.e., repaid on the maturity date).

[h]The actual percentages for Southeastern's two systems are likely higher. But, because the repayment data did not specify the exact year of repayment, in many cases we were unable to determine whether the payment was made before due or at least 10 years before due.

Source: Developed by GAO based on information contained in the three PMAs' power repayment studies and Bonneville's Revenue Requirement Study.

The relatively low percent of debt repaid by Bonneville relates to its investments in nuclear facilities. As of September 30, 1998, Bonneville had about $13.8 billion in debt. Of the $13.8 billion, approximately $4.2 billion relates to nonoperational and canceled nuclear projects, and an additional $2.5 billion relates to one operating nuclear plant of Energy Northwest.

In addition, as we reported previously,[39] Bonneville has faced significant competitive pressure in recent years. In particular, low natural gas prices and improved technology for gas-fired generation facilities combined to put downward pressure on electricity rates in Bonneville's region. Also, excess generating capacity in the region resulted in additional downward pressure on prices in wholesale markets. Thus, Bonneville has had little pricing flexibility in recent years, which has limited its ability to set rates high enough to repay debt at a faster rate.

The relatively low percentage of appropriated debt repaid for Southeastern's Georgia-Alabama-South Carolina System is related primarily to the relatively recent construction of the Richard B. Russell Project.[40] The Russell Project has four operational conventional generating units that provide 300,000 kilowatts of capacity and four nonoperational pumping units[41] intended to provide another 300,000 kilowatts of capacity. The last of the four conventional units came on-line in 1986, and the costs associated with the units are included in the customers' rates.

The four pumping units were completed in 1992. However, because of litigation over their environmental impacts, the four pumping units have never been allowed to operate commercially. As a result, Southeastern has not included the costs of the four pumping units in the customers' rates and has not begun repaying the appropriations.

Because the costs of the conventional units have been in the rate base a relatively short time, Southeastern has repaid little of the federal appropriations. As of September 30, 1998, Southeastern had repaid $31 million (nearly all of which was related to additions to the project) of the $366 million in costs associated with the operational conventional units and none of the $603 million in costs associated with the nonoperational pumping units.

[39] *Federal Electricity Activities: Appendixes to The Federal Government's Net Cost and Potential for Future Losses* (GAO/AIMD-97-110A, September 19, 1997).

[40] The Richard B. Russell Project was originally named the Trotters Shoals Dam.

[41] The pumping units are designed to allow water, after it has passed through generating units, to be pumped back into the reservoir during periods of low demand for electricity. The water can then be used to produce power during periods of high demand for electricity.

The fact that the three PMAs have been repaying large portions of the debt before it is due does not mean that they have repaid as much or more than they would have if required to repay their debt systematically on a normal amortizing basis. For high-interest debt, the three PMAs have generally repaid more than they would have on a normal amortizing basis. For low-interest debt, the three PMAs have generally repaid less than they would have on a normal amortizing basis. This is because, in accordance with provisions in DOE Order RA 6120.2, the three PMAs have generally been repaying the highest interest debt first and deferring repayment of lower interest rate debt.[42, 43] By doing so, the three PMAs effectively reduce their future interest costs.

In contrast, although Bonneville has repaid some of its higher interest rate appropriated debt before it is due, Bonneville's percentage of higher interest rate appropriated debt repaid is relatively low.[44] This is primarily related to its large interest payments on nuclear facilities and the approaching maturity of lower interest rate appropriated debt and Treasury bonds. Table 2 shows the percentages of high interest and low interest rate debt the PMAs have repaid.

[42]However, appropriated debt due in a given fiscal year must be paid.

[43]The PMAs' ability to defer repayment of appropriated debt for a longer period than IOUs and POGs and to repay highest interest rate appropriated debt first offsets their general inability to refinance appropriated debt, which could be a disadvantage in times of declining interest rates. As discussed previously, however, Bonneville's appropriated debt was in fact restructured as of October 1, 1996.

[44]However, Bonneville has repaid a significant portion of its U.S. Treasury bonds before due.

Table 2: Percentages of the PMAs' High Interest and Low Interest Debt Repaid as of Fiscal Year 1998[a]

	Bonneville		Southeastern[b]		Southwestern[b,d]	Western[b,e]	
	Appropriated Debt[b]	Treasury Bonds	Cumberland	GA-AL-SC	Integrated	CVP	SLCA-IP
Percentage of high interest[c] debt repaid	13	81	100	100	99	93	52
Percentage of low interest[c] debt repaid	66	33	62	21	25	53	69

[a]This analysis covered all Bonneville power projects (100% of 1998 power sales); Southeastern's Cumberland and Georgia-Alabama-South Carolina (GA-AL-SC) systems (89% of 1998 power sales); Southwestern's Integrated System (91% of 1998 generating capacity); and Western's Central Valley Project (CVP) and the Colorado River Storage Project of the Salt Lake City Area Integrated Projects (SCLA-IP) (47% of 1998 power sales).

[b]This analysis is of the repayment of appropriated debt related to assets already placed in service. It does not cover appropriated debt for assets not yet placed in service because repayment of those appropriations has not begun.

[c]For each ratesetting system, we calculated a simple average interest rate and considered everything above the average to be high and everything below the average to be low.

[d]Southwestern's data are for fiscal year 1997.

[e]The data needed to calculate the percentages for the Pick-Sloan Project were not available.

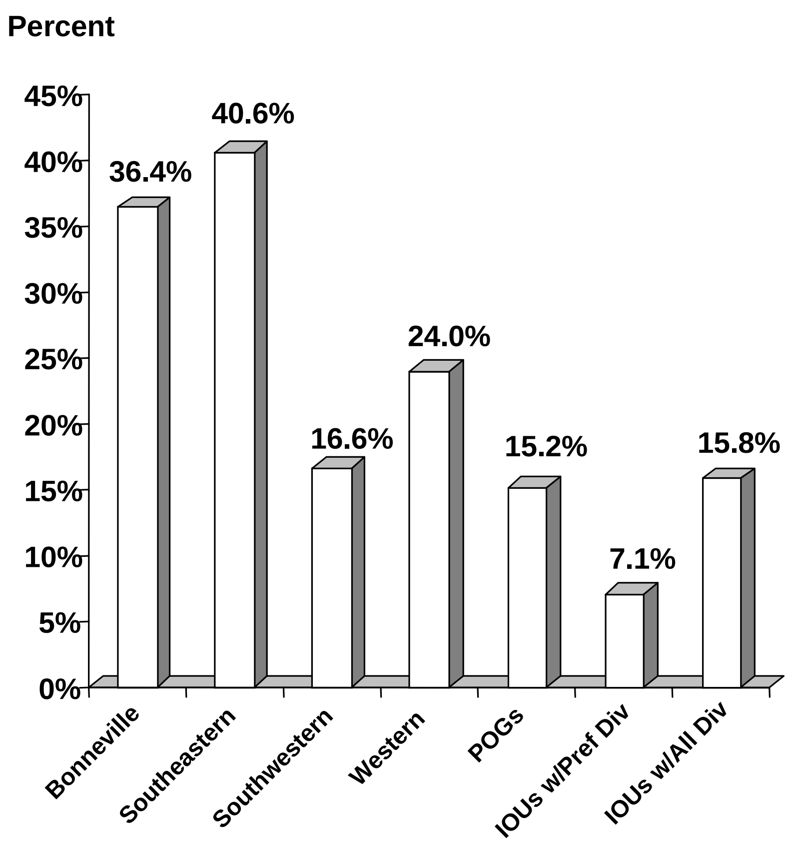
Source: Developed by GAO based on information contained in the three PMAs' Power Repayment Studies and Bonneville's Revenue Requirement Study.

The financing costs of three of the PMAs—Bonneville, Southeastern, and Western—are relatively high compared to those of IOUs and POGs. Their relatively high financing costs mean that Bonneville, Southeastern, and Western have less flexibility to respond to competitive pressures in an increasingly competitive market environment. Moreover, while interest costs are fixed, IOUs have some flexibility in deciding whether to pay dividends to shareholders. Financial flexibility is an important consideration in an increasingly competitive electricity industry. Direct comparisons of financing costs are somewhat difficult because the financing structures of the entities differ. IOUs' financing consists of both equity and debt, while the PMAs' and POGs' financing consists mostly of debt.[45]

[45]The three PMAs' financing generally consists of appropriations that must be repaid to the federal government, with interest. In addition to federal appropriations, Bonneville's financing includes U.S. Treasury bonds and nonfederal debt (i.e., debt held by the public, primarily related to nuclear projects). POGs' financing generally consists of debt capital, which is obtained primarily by issuing electric revenue bonds.

To determine the entities' relative financing costs, we compared the PMAs' and POGs' percentage of interest costs to operating revenues to the IOUs' percentages of interest and dividend (both common and preferred) costs to operating revenues. The results of our analyses are shown in figure 5.

Figure 5: Financing Costs as a Percentage of Operating Revenues for the PMAs, IOUs, and POGs for Fiscal Year 1998



Source: Developed by GAO based on data from the PMAs' annual reports and composite national data on IOUs and POGs from EIA.

Like the percentage of appropriated debt repaid, the relatively high financing costs at Bonneville are related to its nuclear investments and the interest it must pay on its outstanding interest-bearing debt. Two of the nuclear plants Bonneville invested in were terminated and therefore do not generate revenues to offset the interest costs of the associated debt. As of September 30, 1998, Bonneville had outstanding debt of about $13.8 billion.

Of that amount, unpaid federal appropriations totaled about $4.4 billion, bonds owed to the U.S. Treasury totaled about $2.5 billion, and debt related to nonfederal projects totaled about $6.9 billion.

The high financing costs at Southeastern are related to interest costs on the federal appropriations that financed the construction of the Russell Project. Little of the appropriations related to this project have been repaid—only $31 million as of September 30, 1998—and the balance continues to incur an interest cost each year. Although Southeastern pays interest annually ($20.8 million in fiscal year 1998) on the outstanding federal appropriations related to the operational conventional units, it does not pay interest annually on the federal appropriations related to the nonoperational pumping units. Instead, Southeastern has been capitalizing interest annually by adding it to a construction-work-in-progress (CWIP) account; for fiscal year 1998, the capitalized interest amounted to $34.7 million. Thus, the amount to be recovered if the pumping units become operational continues to grow.

As we reported previously,[46] if the nonoperational Russell units are allowed to operate commercially and the costs go into rates, rates would have to be raised to recover the construction and accumulated interest costs reflected in the CWIP balance and to pay interest annually on this amount. Such an increase in interest expense would increase Southeastern's financing costs significantly. For example, if Southeastern were to have paid the capitalized interest of $34.7 million in fiscal year 1998, its financing costs would have been about 60 percent of operating revenues. Southeastern officials expect that the Russell units becoming fully operational would necessitate a substantial rate increase for the Georgia-Alabama-South Carolina System. As we reported previously, the longer the eventual operation of the pumping units is delayed, the greater the costs that will have to be recovered through rates and the greater the potential impact on rates. This situation would pose a challenge to Southeastern in a competitive electricity market because at some point the price of the power generated at the Russell Project may not be competitive.

The relatively high financing costs at Western are related to relatively recent construction projects that carry higher interest rates. For example, about 60 percent of the debt outstanding as of September 30, 1998, for the

[46] *Federal Electricity Activities: Appendixes to The Federal Government's Net Cost and Potential for Future Losses* (GAO/AIMD-97-110A, September 19, 1997).

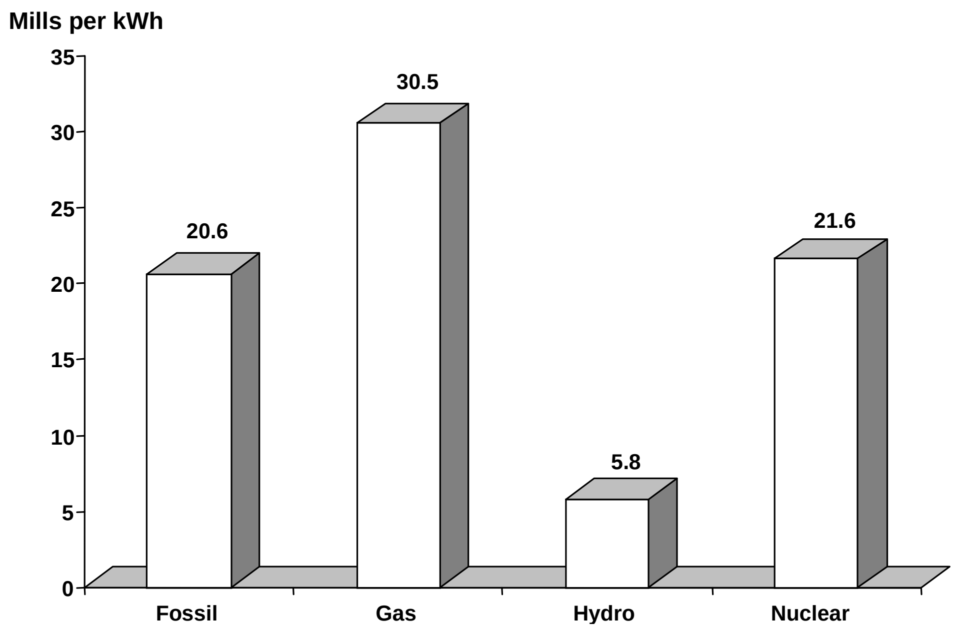
Salt Lake City Area Integrated Projects carry interest rates ranging from 7 percent to 11 percent.

Cost Advantages Enhance PMAs' Competitive Positions

In addition to examining the PMAs' ratesetting practices and how they affect their repayment of debt and financing costs, other factors are critical to any assessment of the PMAs' competitive positions. The PMAs have some important cost advantages that enhance their competitive position, including primarily marketing low-cost hydroelectric power, marketing power from facilities that in many cases were built decades ago at relatively low cost, and not having to generate a return for owners or pay taxes.

One of the PMAs' most significant competitive advantages is that they market primarily low-cost hydroelectric power. Largely because there is no fuel cost associated with hydroelectric power, its costs are substantially lower than for other sources of generation. Figure 6 shows 1998 average data on operating expenses, including fuel costs, for fossil fuel, gas, and hydroelectric and nuclear generation plants operated by IOUs.

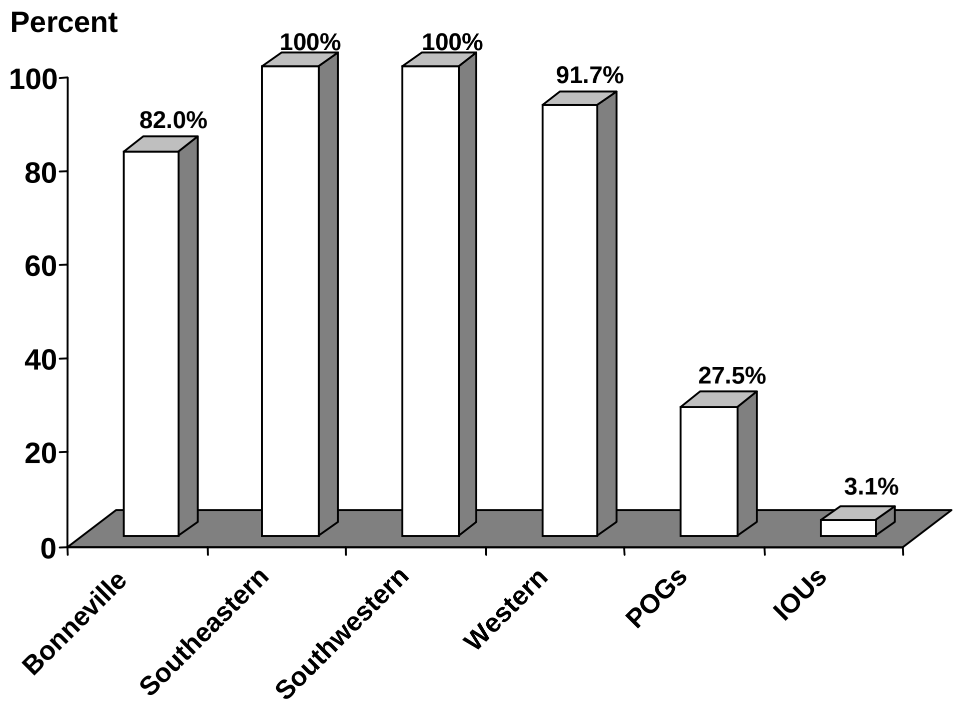
Figure 6: Average 1998 Operating Expenses by Generation Type for Plants Operated by IOUs



Source: Developed by GAO based on data from EIA.

Marketing primarily low-cost hydroelectric power gives the PMAs' a significant overall competitive advantage compared to IOUs and POGs, which generate far less of their power from hydroelectric plants. Figure 7 shows the percentages of power generated by hydroelectric plants for the PMAs, IOUs, and POGs for fiscal year 1998.

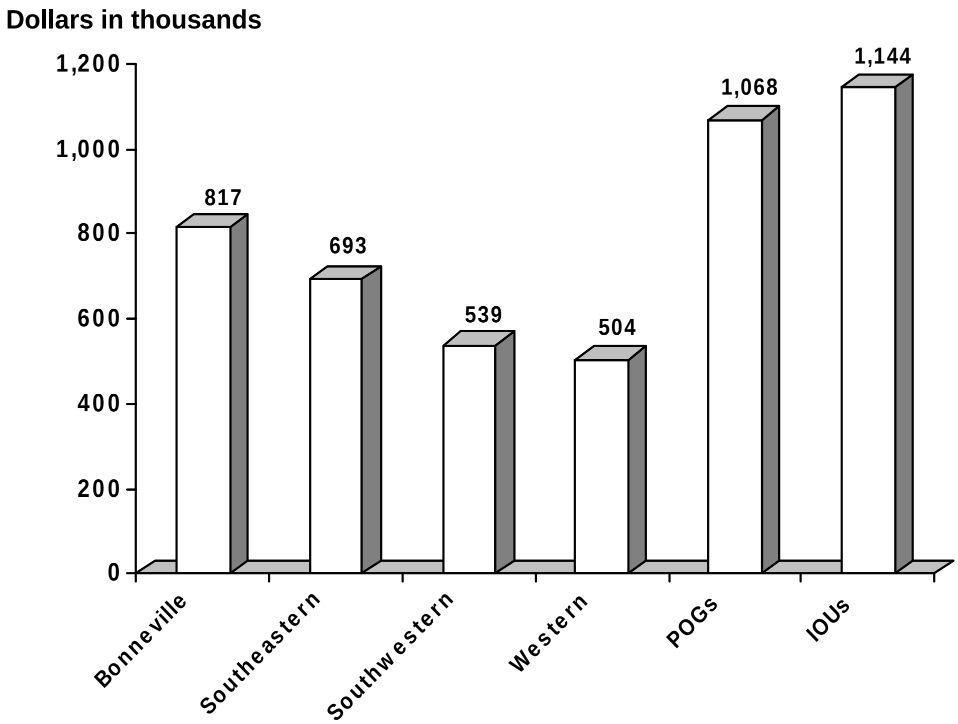
Figure 7: Percentage of Power Generated by Hydroelectric Plants for PMAs, IOUs, and POGs for Fiscal Year 1998



Source: Developed by GAO based on data from the PMAs' annual reports and composite national data on IOUs and POGs from EIA.

Another competitive advantage for the PMAs is that they market power from facilities that were, in many cases, built decades ago at relatively low construction costs. To show the relatively low capital cost of the PMAs' hydroelectric plants, we compared the PMAs' investment in utility plant per megawatt of generating capacity. Figure 8 shows that the PMAs have invested less in utility plant per megawatt of generating capacity than IOUs and POGs.

Figure 8: Investment in Utility Plant per Megawatt of Generating Capacity, 1998



Source: Developed by GAO based on data from the PMAs' annual reports and composite national data on IOUs and POGs from EIA.

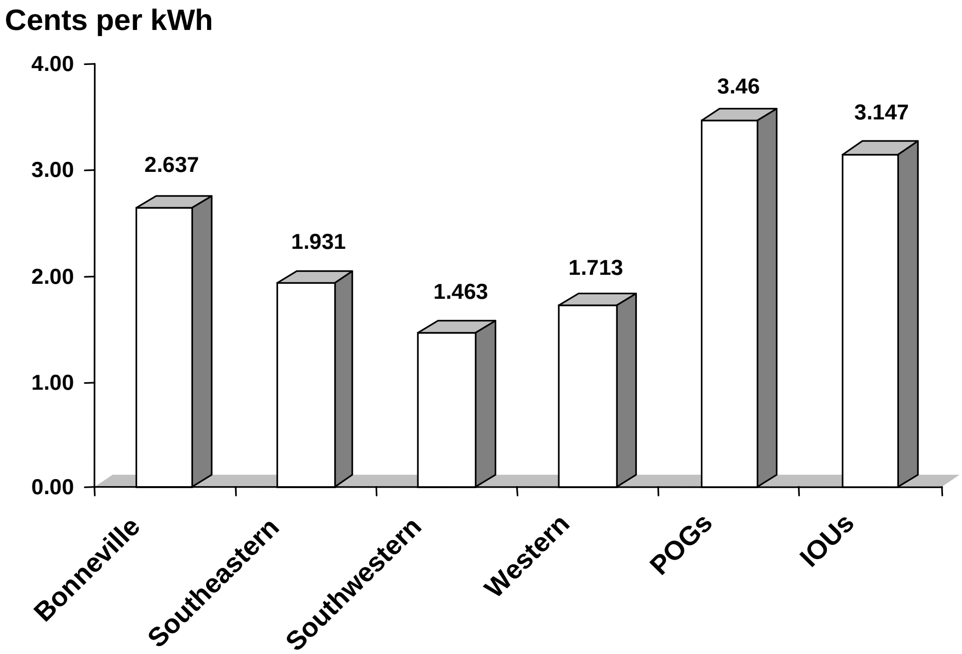
In addition, as discussed previously, the PMAs do not have to generate a return for owners or pay taxes. In contrast, according to EIA, in 1998 IOUs paid dividends to investors totaling about 8.3 percent of operating revenues. Also according to EIA, in 1998 IOUs paid taxes totaling about 13 percent of operating revenues. POGs, as publicly owned utilities, typically do not pay income taxes because they are units of state or local governments. However, many POGs make payments in lieu of taxes to local governments. According to EIA, in 1998 POGs made tax and tax equivalent payments totaling about 2.6 percent of operating revenues. In addition, according to industry sources, some POGs transfer additional funds from their accumulated net revenues accounts to fund other government activities, thereby essentially generating a return for owners. Not having to include a return to owners and tax payments in their rates is a competitive advantage for the PMAs.

Although the PMAs enjoy significant cost advantages, they face some disadvantages relative to IOUs and POGs. For example, due to their reliance on hydropower, the PMAs face weather-related uncertainties to a greater extent than IOUs and POGs. Because the amount of rainfall determines how much power many of the projects marketed by the PMAs can generate, in low water years they may have to purchase power at higher rates to fulfill contracts. In addition, because of the multipurpose nature of federal water projects, operating restrictions may limit the amount of power the PMAs can market. IOUs and POGs that use hydropower also face weather-related uncertainties and operating restrictions, but given the PMAs reliance on hydropower, these factors may have a proportionately larger adverse impact on them. Also, the previously mentioned congressionally-assigned irrigation costs that Bonneville and Western must recover through power rates are obligations that IOUs and POGs do not have.

On balance, the PMAs' cost advantages outweigh their disadvantages. As a result of these cost advantages, the PMAs' power production costs—as reflected in calculations of average revenues per kWh—are lower than those of the IOUs and POGs. Because PMAs generally recover costs through rates with no profit, average revenues per kWh should reflect their full power production costs. For IOUs and POGs, average revenues per kWh should represent costs plus the return generated for owners.[47] As shown in figure 9, the PMAs' average revenues per kWh were considerably below those of IOUs and POGs in 1998.

[47]EIA cautions that average revenues per kWh per unit of energy sold should not be used as a substitute for the price of power. The price that any one entity charges another for wholesale energy comprises numerous transaction-specific factors such as the fee charged for reserving a portion of capacity, the fee for the energy actually delivered, and the fee for the use of the facilities. The fees are influenced by factors such as time of delivery, quantity of energy, and reliability of supply. However, despite its limitations, we believe that average revenues per kWh is a good indicator of relative power production costs since, over time, utilities must recover all costs to remain in business. In addition, analysts and bond rating agencies commonly use the measure in assessing the competitiveness of power rates, and EIA uses it to approximate costs.

Figure 9: Average Revenue per Kilowatthour for Wholesale Sales for 1998 for PMAs, POGs, and IOUs



Source: Developed by GAO based on data from the PMAs' annual reports and composite national data on IOUs and POGs from EIA.

Therefore, despite the PMAs' higher financing costs, the PMAs remain well-positioned because of their inherent advantages.

Agency Comments and Our Evaluation

We received separate written comments from the Department of Energy's Power Marketing Liaison Office, representing the three PMAs, and from the Bonneville Power Administration. The three PMAs' comment letter is reproduced in appendix II. Bonneville's comment letter, and the enclosure accompanying it, is reproduced in appendix III. The three PMAs' comments are discussed below. Bonneville's comments are discussed below and in appendix III. The three PMAs and Bonneville also provided technical comments, which we incorporated as appropriate.

The Three PMAs

In commenting on a draft of this report, the three PMAs stated that the report is a generally fair representation of PMA ratesetting practices. They did, however, request that the report segment discussing PMA cost advantages also include a more detailed discussion of certain cost disadvantages faced by the PMAs to offer an additional perspective on their competitive positions. Specifically, the three PMAs suggested that the report include discussion of the PMAs' (1) inability to refinance, (2) reliance on hydropower, which is subject to weather-related uncertainty, (3) operating restrictions affecting the amount of power available for the PMAs to market, (4) requirement to repay certain costs related to irrigation facilities, and (5) inability to diversify into other lines of business.

We have added some discussion of the first three issues into the report. Regarding the PMAs' inability to refinance, however, it is important to note that this disadvantage is offset by the flexible repayment terms associated with this debt. As we note in our report, the PMAs have the ability to defer repayment of appropriated debt for a longer period than IOUs and POGs and are able to repay highest interest rate debt first while deferring repayment of low interest debt.

Regarding the requirement to repay certain irrigation costs, our report clearly states that Bonneville and Western are required to set rates at levels sufficient to repay certain nonpower costs, such as irrigation, that the Congress has assigned to power users to repay. However, based on the comment of the three PMAs, we have noted in our report that this is an obligation that IOUs and POGs do not have.

Regarding the last item, the PMAs are limited in their choice of services to offer to those that fall within their congressional mandate. We have no basis for agreeing that diversification could accelerate return of the taxpayers' investment. Inherent in this assertion is the presumption that the PMAs would be able to generate excess revenues by diversifying. We have not evaluated whether this is a reasonable assumption.

Bonneville Power Administration

The Department of Energy's Bonneville Power Administration stated that it had significant concerns with our message. Specifically, Bonneville stated that we (1) misconstrue the role of repayment studies in its revenue requirements and rates, (2) inadequately address its risk mitigation activities, (3) mischaracterize its debt obligations and debt management practices, (4) do not consider the "public benefits" that it must provide, and (5) fail to mention the many rate directives found in Section 7 of the Northwest Power Act.

In our view, the comments provided by Bonneville were largely of an elaborative and technical nature. We have incorporated some of the information provided to give additional context to the report. However, the changes incorporated as a result of Bonneville's comments did not alter our overall assessment of its ratesetting and debt repayment practices and we disagree that our report misconstrues these practices. Given the detailed nature of Bonneville's comments, our detailed evaluation of those comments is included in appendix III.

As agreed with your office, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from its date. At that time, we will send copies to Representative Calvin Dooley, Ranking Minority Member, House Subcommittee on Water and Power, Committee on Resources; Representative Joe Barton, Chairman, and Representative Rick Boucher, Ranking Minority Member, House Subcommittee on Energy and Power, Committee on Commerce; Senator Gordon Smith, Chairman, and Senator Byron Dorgan, Ranking Minority Member, Senate Subcommittee on Water and Power, Committee on Energy and Natural Resources. We are also sending copies of this report to the Honorable Bill Richardson, Secretary of Energy; the Honorable Jacob J. Lew, Director, Office of Management and Budget; Judith A. Johansen, Administrator and Chief Executive Officer, Bonneville Power Administration; Charles A. Borchardt, Administrator, Southeastern Power Administration; Michael A. Deihl, Administrator, Southwestern Power Administration; Michael S. Hacskaylo, Administrator, Western Area Power Administration; and other interested parties. Copies will also be made available to others upon request.

If you or your staff have any questions concerning this report, please contact me at (202) 512-9508 or Robert Martin, Assistant Director, at (202) 512-4063. Major contributors to this report were Mary Merrill, Donald R. Neff, and Patricia B. Petersen.

Sincerely yours,

Linda M. Calbom
Director, Resources, Community, and
Economic Development Accounting
and Financial Management Issues

Objectives, Scope, and Methodology

We were asked to determine (1) how the PMAs set their rates to recover costs, (2) how the PMAs' ratesetting practices compare to those of investor-owned utilities (IOU) and publicly owned generating (POG) utilities, and (3) the impact of the PMAs' ability to defer repayment of portions of their debt on their future competitiveness. In determining how the PMAs set their rates to recover costs, we were also asked to examine the assumptions the PMAs use in setting their rates and the processes the PMAs use to set rates to recover costs.

Determining How the PMAs Set Their Rates to Recover Costs

Before setting rates, the PMAs perform power repayment studies (PRS) or, in the case of Bonneville Power Administration, revenue requirement studies (RRS) to identify costs to be recovered and revenue requirements. As a result, to achieve this objective we focused on the PMAs' PRSs and RRSs. We did not examine in detail every analysis performed by the PMAs that is incorporated into these studies and the PMAs' revenue requirements, or verify the results of those analyses. To identify and examine the assumptions the PMAs use in setting their rates and to determine how the PMAs set their rates to recover costs, we (1) interviewed representatives from the four PMAs, (2) contacted the PMAs' external auditors, (3) examined published documentation on the PMAs' ratesetting processes, (4) requested and analyzed written responses related to specific questions about the ratesetting methodologies, including assumptions, used by the PMAs, and (5) analyzed at least one PRS from each of the three PMAs and Bonneville's RRS for its current power rate case. We analyzed the PRSs/RRSs for one or more ratesetting systems from each of the four PMAs that would encompass at least 75 percent of total revenues or 75 percent of total generating capacity for each PMA. Where possible, we traced data in the PRSs and RRS to the audited financial statements of each PMA.

Determining How the PMAs' Ratesetting Processes and Assumptions Compare to Those of IOUs and POGs

To determine how the PMAs' ratesetting processes and assumptions compare to those of IOUs and POGs, we interviewed officials of four POGs and three IOUs and reviewed documentation they provided. We also discussed the ratesetting practices of (1) the IOUs we selected with the public utility commissions (PUC) that regulate them and with representatives from the Edison Electric Institute and (2) POGs with representatives from the American Public Power Association. We selected the IOUs and POGs based on the following criteria.

- Size: We selected relatively large entities to (1) give us as much coverage as possible, (2) increase the likelihood that we examined entities whose scope of operations were similar to the PMAs, and (3) increase the likelihood that the entities would have a ratesetting process comparable in scope to that of the PMAs.
- Geographic location: We selected entities from across the United States to ensure that our analyses considered ratesetting practices that may vary in different regions.
- Status of electric industry restructuring: We selected at least one IOU and one POG from nonrestructured states and all the others from restructured states.
- Location in relation to PMA service territories: We selected at least one IOU and/or one POG from each PMA's service territory.
- Generation from hydro sources: Given the other criteria above, we selected two IOUs and two POGs that either generated or purchased power directly from utilities that generated a portion of their power from hydro sources.

We limited our selection of publicly owned utilities to generating utilities because, in general, they are larger and therefore more likely to have a more formal ratesetting process than nongenerators.

We also (1) interviewed representatives from the four PMAs and from each of the selected IOUs, POGs, and PUCs, (2) examined documentation obtained from the PUCs, (3) interviewed an official from the Federal Energy Regulatory Commission (FERC), and (4) interviewed representatives from industry groups representing IOUs, POGs, and PUCs (Edison Electric Institute, American Public Power Association, and National Association of Regulatory Utility Commissioners, respectively). Based on the data we collected, we compared the PMA ratesetting process and assumptions to those of IOUs and POGs.

Assessing the PMAs' Competitive Positions

To assess the PMAs' future competitiveness, we performed financial analyses based on information in the PRSs and RRS and the PMAs' audited financial statements and compared the results to equivalent information for IOUs and POGs that was obtained from the Energy Information Administration within the Department of Energy. Specifically, we analyzed

- the percentage of the PMAs' debt repaid before due as of September 30, 1998,[1] for selected ratesetting systems at each of the PMAs to determine whether the PMAs have been repaying significant portions of their debt before the year in which they are due;
- the repayment of debt by interest rate as of September 30, 1998,[2] for selected ratesetting systems at each of the PMAs to determine (1) the extent to which the PMAs had repaid their higher interest rate debt first, in accordance with provisions contained in Department of Energy Order RA 6120.2 and (2) the impact this repayment methodology could have on the PMAs' ability to compete in a restructured environment;
- the relative financing costs of the PMAs compared to POGs and IOUs to determine whether the PMAs will have the same financial flexibility to respond to competitive pressures as POGs and IOUs;
- the average operating expenses by generation type (fossil, gas, hydro, and nuclear) to confirm that hydroelectric generation of power is relatively inexpensive;
- the PMAs', IOUs', and POGs' percentage of generation by fuel type as of the end of fiscal year 1998 to determine which entities are positioned to benefit the most from inexpensive sources of generation;
- the investment in utility plant per megawatt of generating capacity to illustrate the relatively low capital cost of the hydroelectric plants that generate the power the PMAs market; and
- the average revenue per kilowatthour for each PMA compared to IOUs and POGs as of the end of fiscal year 1998 to determine the PMAs' cost of power relative to other utilities.

Organizations and Groups Contacted

Federal Entities

Department of Energy
Energy Information Administration
Federal Energy Regulatory Commission

[1] Southwestern's data are for fiscal year 1997.

[2] Southwestern's data are for fiscal year 1997.

Independent Public Accounting Firms

PricewaterhouseCoopers, LLP
Deloitte & Touche, LLP

Electric Utilities

City of Idaho Falls, Idaho Falls, Idaho
Idaho Power, Boise, Idaho
JEA, Jacksonville, Florida
Oklahoma Municipal Power Authority, Edmond, Oklahoma
PG&E, San Francisco, California
San Antonio City Public Service Board, San Antonio, Texas
Virginia Power, Richmond, Virginia

Public Utility Commissions

California Public Utilities Commission, San Francisco, California
Idaho Public Utilities Commission, Boise, Idaho
Virginia State Corporation Commission, Richmond, Virginia

Trade or Interest Group Associations

American Public Power Association, Washington, D.C.
Edison Electric Institute, Washington, D.C.
National Association of Regulatory Utility Commissioners, Washington, D.C.

Comments From Southeastern, Southwestern, and Western Area Power Administrations

Department of Energy
Power Marketing Liaison Office
Washington, DC 20585

March 20, 2000

Jeffrey C. Steinhoff
Acting Assistant Comptroller General
United States General Accounting Office
Washington, DC 20548

Dear Mr. Steinhoff:

This letter serves as the written comments of the Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration on the General Accounting Office (GAO) draft report, "POWER MARKETING ADMINISTRATIONS: Their Ratesetting Practices Compared to Those of Nonfederal Utilities" (GAO/AIMD-00-114). We appreciate the opportunity GAO provided us to review and comment on its draft report. In general, we found the draft report to be a fair representation of PMA ratesetting practices.

On Wednesday, March 15, 2000, representatives of these three power marketing administrations (PMAs) participated in a telephone conference call with the GAO staff who drafted the report. The purpose of the conference call was for the PMA representatives to provide comments of a technical or editorial nature on the draft for GAO to consider including into the final report. We believe the inclusion of our comments will improve the accuracy of the report and ask that they be incorporated.

Now on pp. 26-38.

The three PMAs would also like to make one comment of a policy nature. Starting on page 29 of the draft report and continuing until page 46, there is a section of the draft entitled "Overall the PMAs Are Well Positioned Competitively" that describes in some detail the cost advantages that give PMAs competitive advantages in the newly restructuring wholesale power markets. We believe the draft report would benefit if this section was more evenly balanced with additional discussion of certain cost disadvantages the PMAs face.

PMA cost disadvantages include:

Inability to Refinance: Whereas investor-owned utilities (IOUs) and publicly-owned generating utilities (POGs) often have the flexibility to refinance their existing debt, the three PMAs' interest on investment remains locked at the rate in existence when the investment was placed in service. During times of interest rate declines, refinancing is a distinct advantage to IOUs and POGs that is unavailable to PMAs.

Variable Generation: The PMAs' primary generating resource -- falling water -- varies based on rainfall. As opposed to fossil-fueled and nuclear generating plants, whose power output is much more constant, hydropower is subject to weather-related uncertainty. PMA contracts generally necessitate the purchase of capacity or energy during times when generation is unavailable, such as drought. The costs of such purchases exert upward pressure on PMA power rates.

Operating Restrictions: In addition to variable generation due to water conditions, hydropower plants are subject to operating restrictions caused by the multipurpose nature of Federal water projects. Operating restrictions are imposed for environmental, navigation, water supply, recreation, and flood control reasons. Such restrictions may prevent maximum generation during times of high power demand, when PMA electricity is most valuable; or may force generation to occur during low power demand periods when electricity prices are low. We recognize that hydropower plants owned by IOUs and POGs also face operating restrictions, but it is rare for other kinds of utilities to be as dependent on hydropower as the PMAs are. Hence, these operational restrictions have a proportionately larger adverse impact on PMAs than on other kinds of utilities.

Irrigation Assistance: Western Area Power Administration (Western) faces another competitive disadvantage due to its legislatively mandated requirement to repay capital investments in the irrigation features of Federal water projects that are beyond the irrigators' ability to repay. This assistance to irrigators by the power customers of Western has direct implications for Western's power rates. The magnitude of this cost disadvantage is not insignificant -- at the end of FY 1998, Western's power customers were responsible for repaying $3.1 billion of nonpower investment. To our knowledge, there is no similar cost disadvantage where power customers of other kinds of utilities are expected to bear nonpower related costs.

Inability to Diversify: Finally, as the electric utility industry moves through a period of restructuring, it has become common to see electric utilities diversify into other business lines that they believe will increase value for their shareholders. The PMAs, in contrast, are limited in their choice of services to offer to those that fall within their Congressional mandate. This limitation, while appropriate, places the PMAs at a competitive disadvantage due to their inability to develop new revenue streams that could accelerate return of the taxpayers' investment.

We recognize that certain of these disadvantages are mentioned in the draft report. However, we believe the tone and balance of the report would benefit from additional discussion of these factors.

Thank you again for the opportunity to provide comments.

Sincerely,

Jack Dodd for
Timothy J. Meeks
Assistant Administrator

cc. Richard Glick, S-2
Juanita McDuffie, CR-2
Jeffrey Stier, BPA

Comments From the Bonneville Power Administration

Note: GAO's comments supplementing those in the report text appear at the end of this appendix.

Department of Energy

Bonneville Power Administration
Washington, D.C. 20585

March 23, 2000

In reply refer to: KGN-7

Mr. Jeffrey C. Steinhoff
Acting Assistant Comptroller General
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Steinhoff:

Thank you for furnishing us with a copy of a Draft Report entitled Power Marketing Administrations: Their Ratesetting Practices Compared to Those of Nonfederal Utilities (GAO/AIMD-00-114), dated March 2000. The Bonneville Power Administration (Bonneville) appreciates the opportunity the General Accounting Office (GAO) has provided us to review and comment on the first draft of your report, which you sent us on March 10, 2000, and to discuss our comments with GAO staff. As we stated during our March 16, 2000 exit conference, we have serious and fundamental concerns with the accuracy of the first draft of your report. However, we understand that many of our concerns were addressed in a following draft, which we were not provided an opportunity to review. As we discussed with GAO staff, we believe the inclusion of our comments will improve the accuracy of the GAO report and ask that our comments be incorporated in the final report.

See comment 1.

On Thursday, March 16, 2000, Bonneville participated in a telephone conference call with GAO staff who drafted the Draft Report. The purpose of the call was to provide GAO with our comments on the Draft Report and to correct misunderstandings with regard to the way Bonneville sets rates. Bonneville provided GAO with a copy of our comments in advance of the telephone conference call. GAO responded positively to our comments and verbally agreed to include many of them in their final report. On Monday, March 20, 2000 Bonneville received an annotated copy of our comments with notes describing how GAO would include our comments in their final report, but we were not given the opportunity to see which comments had been included and the context in which they were used.

See comment 1.

Since we did not see how our comments were incorporated in the redrafted Report, this letter primarily reiterates our chief concerns with the March 10, 2000 Draft Report as discussed with GAO on March 16, 2000. Also, Bonneville staff previously forwarded to your staff a number of technical and editorial comments to the Draft Report.

See comment 1.

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As stated above, we do have several significant concerns with the March 2000 Draft Report. Our concerns are discussed in the enclosure to this letter and includes: (1) the role of repayment studies in Bonneville's revenue requirements and rates, (2) the implications of risk mitigation on Bonneville's cost recovery and rates, (3) the technical mischaracterization of Bonneville's debt obligations and debt management practices, and (4) the lack of reference to the "Public Benefits" Bonneville must provide. Further, Bonneville is concerned that the Draft Report fails to take into account the many rate directives found in Section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (NW Power Act) and the procedures governing Bonneville rate hearings.

Again, we believe the inclusion of our comments will improve the accuracy of the GAO final report and more fairly represent Bonneville's ratesetting practices. Thank you for allowing us the opportunity to comment on the Draft Report.

Sincerely,

Jeffrey K. Stier
Vice-President for National Relations

Enclosure

cc:
R. Glick, S-2
J. McDuffie, CR-2
T. Meeks, PML

<u>**Bonneville Power Administration (Bonneville) Comments on GAO Draft Report**</u>
Power Marketing Administrations: Their Ratesetting Practices Compared to Those of Nonfederal Utilities (GAO/AIMD-00-114), March 2000.

See comment 2.

1. **The Draft Report misconstrues the role of repayment studies in Bonneville's revenue requirements and rates.**

See comment 2.

Repayment studies are not synonymous with revenue requirements, and at Bonneville, they are not "used to set rates" as the Draft Report suggests. At Bonneville, repayment studies are used for the limited purpose of determining amortization and gross Federal interest amounts for each year of a cost evaluation period. For example, a 2002 repayment study is used to determine amortization and gross Federal interest amounts for 2002. These calculations in repayment studies then serve as one of several key inputs to revenue requirements.

See comment 3.

Repayment studies are prepared separately for generation debt and transmission debt for each year of a cost evaluation period. Each repayment study has a horizon of up to 50 years. The total debt service stream in each function is levelized over the repayment horizon at the lowest possible level such that each obligation is scheduled for repayment by no later than its due date (maturity). Within these parameters, Bonneville has the flexibility to schedule repayment of higher interest rate obligations before lower interest rate obligations.

See comment 4.

Revenue requirements are set at the higher of forecasted accrued expenses (including depreciation expense) or cash requirements (including cash requirements to repay Federal debt and to mitigate risks – see below). Revenue requirements include forecasts of operating expenses, including depreciation expense; Federal interest expense; and planned net revenues to fulfill cash requirements, including risk requirements.

See comment 5.

Spending estimates are not the simple function of historical analyses and escalation factors as the report suggests, but the product of extensive, rigorous planning processes involving all key stakeholders, including investor-owned utility (IOU) stakeholders. Significant policy issues and initiatives are also made subject to rigorous consultation and comment, such as development of the fish and wildlife funding principles and Bonneville's firm power allocation and marketing policy.

See comment 6.

Once revenue requirements have been developed, costs are allocated to classes of service (products) and rates are designed. A revenue forecast is then prepared, which Bonneville then tests and uses to demonstrate to the Federal Energy Regulatory Commission (FERC) that proposed rates will be adequate to recover costs.

See comment 6.

- How Bonneville sets rates and recovers costs is comparable to IOU practices. Bonneville's planned expenses and capital investments for the rate period are made subject to public review and comment before a rate proposal is initiated. The IOU's use a historical test period, adjusted for known and measurable changes. These costs are then subject to review and comment during the rate proceeding. Both Bonneville and the IOU's include operating expenses, depreciation expense, and interest expense in their revenue requirements.

See comment 4.

- Generally, both Bonneville and the IOU's recover the capital costs of their investments through the depreciation expense charged to ratepayers. Bonneville uses straight-line depreciation over the service life of its investments, which is similar to the IOU approach. In this way Bonneville and the IOU's can collect from ratepayers the entire capital cost over the investment's service life. However, as stated above, when the amount of projected debt amortization exceeds depreciation, Bonneville will include the higher amortization amount in its revenue requirement. This is one of the tools Bonneville has available to help assure that payments to Treasury are made in full and on time.

See comment 3.

- Bonneville prepares a forecast of costs and revenues for each year of a rate period. But a repayment study does not include a true forecast of costs beyond the cost evaluation period as the Draft Report suggests. Repayment studies are used to optimize debt service for the debt that is outstanding in the cost evaluation period for purposes of determining Federal debt service (amortization, gross interest) for the cost evaluation period. The 50 years of data in a repayment study is non-escalated and represents a stream of debt service payments associated with debt outstanding in the cost evaluation period, plus a forecast of system replacements based on the system as it exists in the cost evaluation period. Repayment studies do not attempt to forecast new investment beyond the cost evaluation period. As such, they are not true forecasts of the next 50 years.

See comment 7.

2. The Draft Report does not address adequately the implications of risk mitigation strategies and tools on Bonneville cost recovery and rates.

See comment 7.

By law, Bonneville's payments to Treasury are the lowest priority of revenue application, meaning that these payments are the first to be missed if reserves are insufficient to pay all bills on time. For this reason, Bonneville expresses its potential for recovering costs as the probability of being able to make payments to Treasury—the last creditor in line-- in full and on time. In Bonneville's current proceeding for wholesale power rates, the Treasury Payment Probability (TPP) target is a 97.5 percent probability that payment to Treasury will be recovered on time and in full in each year of the rate period (or 88 percent for the 5-year period). This target represents the full implementation of Bonneville's financial policy that was developed through an extensive public involvement process.

See comment 7.

Bonneville's rate setting includes a robust and complex analysis of both operating risks (associated with hydro conditions, market prices, economic conditions, and generating resource performance), and non-operating risks (fish recovery and other cost uncertainties). Risk mitigation tools are developed to mitigate the risks so that the TPP target is achieved. Planned net revenues for risk (PNRR) is a key tool, which is an adder to revenue requirements. Another key tool proposed in the current rate proceeding is a rate adjustment mechanism (called Cost Recovery Adjustment Clause or CRAC) that triggers in the event risks cause a large decline in reserves. In addition, Bonneville has cut costs aggressively to minimize its exposure to market and other risks that may prevent recovery of costs.

See comment 7.

- Risk mitigation tools are key ingredients in Bonneville revenue requirements and rates. TPP is the key measure of potential to recover total costs.

See comment 8.

- Bonneville does not assume average water conditions as the Draft Report suggests. A full range of hydro risks are modeled using state-of-the-art techniques based on 50 years of hydrological data and projected river operations for fish recovery. Further, market price risks are modeled and quantified using comparably sophisticated techniques and expertise. Bonneville then designs such measures as "planned net revenues for risk" and a rate risk adjustment mechanism, to mitigate these risks and assure that all costs will be recovered on time and in full.

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See comment 9.

- Risk management strategies are what have enabled Bonneville to recover all costs, including all payments to Treasury, on time and in full for 16 consecutive years.

See comment 10.

- Bonneville's explicit recognition of risk and use of PNRR in rates is different from the IOU approach, which is to include an adequate return to shareholders for the risks they bear. That is, dividend payments to shareholders can be reduced or withheld if the IOU has insufficient cash to pay interest and dividends. Like Treasury for Bonneville, IOU shareholders are the last to be paid. Unlike Bonneville, IOU's compensate for risk by including a higher return (profit) for shareholders in the revenue requirement.

See comment 11.

3. The Draft Report mischaracterizes Bonneville's debt obligations and debt management practices.

See comment 11.

Bonneville's debt portfolio consists of appropriations, Treasury bonds and nuclear project debt. Similar to the IOU's, Bonneville's debt management objective is to minimize the agency's total debt service costs. Debt service on Treasury bonds and appropriations is optimized taking into account third party obligations. Since the 1996 Bonneville Appropriations Refinancing Act, all of Bonneville's obligations have been assigned prevailing market interest rates, with the effect that the weighted average interest rate on appropriations is equivalent, even higher than, the rate on bonds issued to Treasury.

See comment 12.

- The report's use of the term "financing costs" is confusing because what is meant is interest expense and return on equity (for IOU shareholders).

See comment 13.

- It is unclear what is being measured on Table 1: Percentages of PMAs' Debt Repaid Before Due. It appears to be calculating payments as a percentage of original appropriations (17 percent as shown). However, if calculating payments ahead of due dates as a percentage of appropriations repaid, Bonneville has repaid 68 percent of appropriations ahead of due dates. Contrary to what footnote 3 suggests, Bonneville did provide GAO with repayment data from 1991 to 1998.

See comment 14.

- In the context of Treasury payments, the term "deferral" has a very specific meaning. "Deferral" refers to a planned interest payment to the US Treasury that has been missed because current financial reserves are inadequate. Missed interest payments are capitalized, assigned the prevailing Treasury interest rate, and given payment priority for the next year. The Draft Report improperly uses the term "defer" to characterize the absence of a fixed repayment schedule for appropriations or the flexibility to schedule repayment based on highest interest first. Indeed, the report may suggest to some that balloon payments on appropriations are common and acceptable. As explained above, Bonneville levelizes its debt service over the horizon of a repayment study such that each obligation is scheduled for repayment by no later than its due date. Levelization is a policy requirement that forces a higher level of repayment to be scheduled sooner rather than later. Since its inception, Bonneville has repaid over $4.0 billion in bonds and appropriations, and because of the levelization policy, over 75 percent of this amount has been repaid ahead of due dates. FERC tests the adequacy of our repayment schedules as a pre-condition to approving Bonneville's rates. *Bonneville enjoys no freedom to systematically push back repayment to due dates as the Draft Report seems to suggest.*

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See comment 10 and footnote to comment 10.

- Cumulatively, Bonneville's payments to Treasury have totaled over $15.5 billion of which $4.0 billion is principal on appropriations and bonds. Bonneville has never missed a due date for principal repayment. Bonneville has deferred an interest payment only once in it history. Currently our financial reserves are sufficient to mitigate most risks in the near future.

See comment 10.

- Appropriations obligations outstanding at the end of FY1999 total $4.1 billion and Treasury bonds total $2.5 billion. The weighted average remaining due dates/maturities on appropriations is about 24 years, and on bonds about 17 years. Given current repayment policy, essentially all of these obligations will have been retired by about 2018. The Refinancing Act limited the amount of appropriations that can be repaid ahead of its due date to $100 million during the first five years after implementation of the Act, from 1997 to 2001.

See comment 15.

- Approximately 38 percent of Bonneville's debt is associated with investments that do not generate revenues, including fish and wildlife investments and two terminated nuclear plants.

See comment 16.

COMPARISON OF BONNEVILLE APPROPRIATIONS TO IOU CAPITAL

Bonneville Appropriations	***IOU Capital***
No call premium for early payment	Call premiums are common
Due date is expected services life or 50 years, whichever is shorter	Can structure the maturity of debt instruments
Amortization scheduled replanned frequently under levelization policy. Most amortization occurs in advance of maturity date.	Balloon amortization on maturity date
Must repay 100%	Equity is never repaid
Collect planned net revenues for risk to mitigate risks and assure repayment	Allow higher return on equity than on debt to compensate for risk
Annual appropriations controlled by Congress	Unlimited access to the capital markets
Can't refinance without legislative approval	Can refinance or roll over
Interest rate assignment is prescribed by law	Interest rates based on credit rating

See comment 17.

4. The Draft Report Does Not Consider the "Public Benefits" Bonneville must provide

See comment 17.

The Draft Report points out cost advantages the PMAs have that enhance their competitive position. According to the Draft Report, these include marketing low-cost Federal power generated from facilities built decades ago and the fact that the PMAs are not required to pay taxes or generate a return for owners. The Draft Report claims that because of these cost advantages "the PMAs overall are well positioned competitively".

See comment 17.

While Bonneville does not generate a profit or pay taxes, it does incur many costs as a result of public responsibilities placed on it by law that affect Bonneville's competitive position. Some of Bonneville's public responsibilities, such as its obligation to protect, mitigate and enhance fish and wildlife, are unique and expensive. Bonneville is setting rates to recover an annual average of

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See comment 17.

$333 million plus operational expenses (average $190 million) during the next rate period for fish recovery alone. Additionally, Bonneville is required by law to extend the benefits of Federal Columbia River Power System to residential and small farm consumers of investor-owned utilities in the Region; by the end of FY 2001 Bonneville will have paid $3.2 billion to meet this requirement. This program is not mentioned in the Draft Report in the list of additional costs that Bonneville incurs. Bonneville must also return roughly $800 million to the U.S. Treasury for irrigation investments that are beyond the ability of water users to pay.

See comment 18.

5. The Draft Report Fails to Mention the Many Rate Directives Found in Section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (NW Power Act) and the Procedures Governing Bonneville Rate Hearings.

See comment 18.

Bonneville's rate setting process is unlike the other 3 PMAs, since it is governed by the Northwest Power Act, which describes in detail how and when Bonneville must review and revise its rates. Contrary to the Draft Report, the Northwest Power Act is not the only statute that governs Bonneville's ratemaking. The additional statutes include the Bonneville Project Act, 16 U.S.C. 832, et seq., and the Federal Columbia River Transmission System Act, 16 U.S.C. 838 et seq.

See comment 18.

Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. §839e(a)(1), directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be repaid by power revenues) over a reasonable period of years. These basic requirements are fairly similar to the other PMAs. However, many other aspects of Bonneville's rate setting process are unlike the other 3 PMAs, since the Northwest Power Act describes in detail substantive and procedural requirements regarding the development of Bonneville's rates.

See comment 18.

Section 7 of the Northwest Power Act provides very clear directives that Bonneville must follow in developing its rates. For example, in addition to a repayment study, section 7(b)(2) provides that Bonneville must conduct a test to ensure that its public utility customers' firm power rates are no higher than rates calculated using five specific assumptions that remove certain effects of the Northwest Power Act. Section 7(c) gives specific guidance to the Administrator regarding the rates charged to Bonneville's direct service industrial customers. Other subsections of the law were designed to address issues pertaining to different kinds of wholesale customers, such as low-density discounts. Section 7(g) provides important direction that Bonneville must recover in its rates the costs of conservation, fish and wildlife measures, uncontrollable events, reserves, and other operational functions.

See comment 18.

These various directives from the Northwest Power Act have prescribed the methodology that Bonneville must follow in setting its rates. In addition, since it is self-financing, Bonneville must prepare for risks of over or under collection of revenues, so the ratemaking process includes a number of risk mitigation strategies.

See comment 18.

Section 7(i) of the Northwest Power Act prescribes rules for the conduct of the ratemaking process. It provides procedural requirements to be used when developing rates, including publication of notice in the Federal Register of the proposed rates, a formal evidentiary hearing before a hearing officer, an opportunity to submit oral and written comments, and an opportunity to refute or rebut other material submitted for the

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See comment 18.

record. Bonneville has expanded on these statutory directives by promulgating rules for general rate proceedings to aid in the conduct of these hearings. *See Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986). These Procedures implement the statutory section 7(i) requirements.

See comment 19.

With regard to the description of Bonneville's ratemaking process in the Draft Report, a number of statements were inadvertently incorrect. Bonneville's field hearings are held at different times in different cities with the general public, but also for a brief period of time while Bonneville is conducting its formal evidentiary hearing. The field hearings do not completely come *before* the formal hearings. In addition, at a prehearing conference, Bonneville makes available the testimony, studies and documentation (some 5,000 pages) that support and are part of Bonneville's initial proposal. A significant time after Bonneville files this direct case (approximately 70 days in Bonneville's current rate case), the parties, *not* Bonneville, file their direct cases, which present their positions on all rate issues including but not limited to, responding to Bonneville's initial proposal. Also, Bonneville and the parties file rebuttal testimony to the *parties'* direct cases only, *not* to Bonneville's direct case, which they already addressed in their direct cases. Also, Bonneville and the parties may cross-examine each other's witnesses, but cross-examination is not limited to "specific points" in those direct and rebuttal cases; instead it is open to all relevant issues. Finally, at the close of the formal hearings, only the parties file briefs, *not* Bonneville as stated in the Draft Report. Consequently, there are a number of changes that should be made to the chart summarizing Bonneville's ratemaking process. A copy of proposed changes has been forwarded to your staff.

See comment 20.

The Energy Policy Act of 1992 (EPA'92) sets forth additional ratemaking requirements for transmission rates to be applied in connection with transmission access ordered by the Federal Energy Regulatory Commission. The ratemaking process is governed by Bonneville's rule for general rate proceedings.

See comment 20.

Bonneville's rates become effective upon confirmation and approval by FERC. FERC's review is appellate in nature, based on the record developed by the Administrator. The Commission may not modify rates proposed by the Administrator, but may only confirm, reject or remand them. Section 7 provides clear standards that FERC must apply in the review and approval of Bonneville's rates. FERC is to confirm that Bonneville's rates are sufficient to assure repayment and are based on total system costs. With regard to transmission rates, Bonneville must equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system. Additional criteria regarding Bonneville's transmission rates are provided in other statutes. Bonneville is directed to establish rates that recover costs -- the Northwest Power Act's rate directives establish the manner in which Bonneville allocates the cost of supplying resources to meet loads.

See comment 18.

Bonneville is also governed by other laws and policies and processes which have been adopted over the last 20 years, which among other things, have set program levels, determined fish and wildlife obligations, and established a strategy for guiding utility wholesale contracts (the "Subscription Strategy").

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The following are GAO's comments on the Bonneville Power Administration's letter dated March 23, 2000.

GAO Comments

1. Discussed in the "Agency Comments and Our Evaluation" section of the report.

2. We disagree that our report misconstrues the role of repayment studies in Bonneville's revenue requirements and rates. In our report, we focus on Bonneville's revenue requirements studies (RRS), which encompass the debt service analyses contained in its repayment studies. In addition, we state that three of the PMAs use power repayment studies (PRS) to identify revenue requirements and demonstrate cost recovery as a key part of ratesetting, while Bonneville uses RRSs for similar purposes.

3. We recognize that, for Bonneville, repayment studies are prepared separately for generation debt and transmission debt for each year of a cost evaluation period. However, in response to Bonneville's comments and technical comments provided by the three PMAs, we clarified in our report that we focused on the PRSs and RRSs, which encompass the full range and amount of costs to be recovered. We also clarified that there are key differences between (1) repayment studies and revenue requirements and (2) cost evaluation periods and repayment periods.

4. We added language to acknowledge that Bonneville's revenue requirements are set at the higher of forecasted accrued expenses (including depreciation expense) or cash requirements.

5. Our report acknowledges the complexity of preparing the studies that form the basis for ratesetting. However, it was not our intent to describe every facet of the process for Bonneville or the other entities we reviewed. However, to the extent policy issues resulted in costs to be recovered through power rates and therefore become a part of revenue requirements, we discussed the cost in our report. For example, our report states that the costs of protecting fish and wildlife and mitigating damage to fish affected by the construction and operation of the Federal Columbia River Power System are a consideration in the revenue requirements analysis that underlie Bonneville's rates. We also state that the estimated range of funding for

these activities is $438 to $721 million annually for fiscal years 2002 through 2006.

6. We agree that rates are designed after developing revenue requirements and have added clarifying comments to that effect. Our report discusses the similarities and differences between the IOUs and the PMAs fairly extensively. The report states that the IOUs' rate proposals undergo a public process similar to the PMAs' process and describe the types of costs (e.g., depreciation, interest, and operating expenses) the IOUs recover through rates. Further, we discuss that IOUs use a historical test period, adjusted for known and measurable changes. However, contrary to the comment, the historical test period used by the IOUs we contacted is much shorter than the period used by Bonneville and the other PMAs and is therefore a difference rather than a similarity.

7. In our report we state that, in setting rates, Bonneville considers operating risks, such as weather-related uncertainties associated with the reliance on hydropower generation, and nonoperating risks such as fish and wildlife protection and mitigation expenditures. We also discuss Bonneville's objective of setting rates that will result in an 88 percent probability that Treasury payments will be made on time and in full over a 5-year period. However, as a result of Bonneville's comments we expanded our discussion of Bonneville's risk mitigation considerations and targets. We expanded our discussion of the types of risks that Bonneville considers in developing its revenue requirements. We also added a discussion of Bonneville's target of setting rates that will result in a 97.5 percent probability that payments to the Treasury will be made on time and in full for each year of the rate period (88 percent over a 5-year period). The other issues raised in this comment provide a level of detail that is not required to accomplish the objectives of our review.

8. We recognize that Bonneville does not simply assume that average water conditions will prevail in the future when setting rates. We revised our report to say that historical hydrological data and projected river operations are used to project future water conditions.

9. We do not agree with Bonneville's statement that its risk management strategies have enabled Bonneville to recover all costs on time and in full for 16 consecutive years. As we state in the current report, previous GAO reports[1] have demonstrated that the PMAs—including Bonneville—are not recovering all of the federal government's costs of generating, transmitting, and marketing power. In those reports, GAO estimated that the unrecovered costs incurred by the federal government related to Bonneville's operations totaled about $2,085 million for fiscal years 1992 through 1996.

10. This information provided by Bonneville provides a level of detail that is not required to accomplish the objectives of our review.[2]

11. We disagree with Bonneville's statement that our report mischaracterizes its debt obligations and debt management practices. In our report we clearly state that Bonneville's rates must cover the repayment of appropriations and bonds issued to the Treasury and debt service on nonfederal bonds primarily for the construction of Energy Northwest (formerly the Washington Public Power Supply System) nuclear plants. Further, we state that Bonneville had an outstanding debt of about $13.8 billion as of September 30, 1998, of which $4.4 billion related to unpaid federal appropriations, $2.5 billion related to bonds owed to the U.S. Treasury, and $6.9 billion related to its nonfederal project (e.g., nuclear projects) debt. Moreover, regarding debt management, in our report we state that in setting rates the PMAs assume that they will, where possible, mitigate interest costs by paying the highest interest rate debt first. This is consistent with Bonneville's statement that its debt management objective is to minimize its total debt service costs. Examining the effect of the 1996 Bonneville Appropriations Refinancing Act was beyond the scope of our review.

[1] *Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities* (GAO/AIMD-96-145, September 19, 1996); *Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses,* volumes 1 and 2 (GAO/AIMD-97-110 and 110A, September 19, 1997); and *Power Marketing Administrations: Repayment of Power Costs Needs Closer Monitoring* (GAO/AIMD-98-164, June 30, 1998).

[2] Bonneville subsequently informed us that the statement in its comment letter that it has deferred an interest payment only once in its history is incorrect. According to Bonneville, it deferred interest payments in four separate years during the 1980s, with the last deferral occurring in fiscal year 1983.

12. Our report makes it clear that the components of "financing costs" are (1) interest costs for the entities financed through debt only and (2) interest and dividends (common and preferred) for the entities financed through a combination of debt and equity. We analyzed and reported these financing costs as a percentage of operating revenues for the PMAs, IOUs, and POGs as an indicator of financial flexibility, which is an important consideration in an increasingly competitive electricity industry.

13. As stated in the explanation provided with table 1, the table illustrates the percentages of debt (1) repaid before the year in which the debts are due and (2) repaid at least 10 years before the year the debts are due. As explained in our discussion with Bonneville officials on March 16, we calculated the percentages repaid based on the *total appropriated debt incurred over time* that financed the PMAs. At that time, the Bonneville officials explained that their 68 percent figure was calculated based only on early repayments as a percentage of the amount of appropriated debt Bonneville had *actually repaid to date*, not on total appropriated debt incurred. The Bonneville officials agreed that our 17 percent figure was accurate as presented. While Bonneville did provide us with data from 1991 to 1998, that data were not sufficiently detailed for us to perform a complete analysis.

14. While we recognize that the term "deferred payments" can be used to describe missed interest and operations and maintenance expenses, our report uses the common dictionary definition of deferral (i.e., to "put off or delay").[3] We believe we are correct in characterizing the PMAs' ability to repay highest interest rate debt first and low interest rate debt later as deferring the repayment of low interest appropriated debt. However, we did add some language to the report clarifying that we are referring to the repayment of appropriated debt and that the deferral is until the years due and not beyond. We do not believe that our report suggests that the PMAs systematically make balloon payments by waiting until the year due to repay appropriated debt. In our report, we state that while the PMAs have the ability to defer the repayment of appropriated debt, they have repaid significant portions before the years in which they are due. In addition, table 1 shows that the PMAs have repaid significant portions of their appropriated debt

[3] *Merriam-Webster's Collegiate Dictionary*, tenth edition. Springfield, Massachusetts: Merriam-Webster, 1993.

before it is due, although Bonneville has repaid a lesser percentage before due than have the other three PMAs.

15. We state in our report that Bonneville's rates must cover debt service on $6.9 billion in nonfederal bonds used primarily to construct Energy Northwest nuclear plants. We added language to our report that two of these nuclear plants are nonoperational and therefore do not generate revenues to offset the interest costs of the associated debt.

16. We do not believe it necessary to include in our report the table Bonneville provided that compares its appropriations to IOU capital. As discussed above, we adequately and accurately characterized Bonneville's debt obligations and debt management practices.

17. We disagree with Bonneville's statement that we did not consider the impact on its competitive position of its expenditures on "public benefits" initiatives. We considered the impact that expenditures related to the primary benefit cited by Bonneville—environmental mitigation and enhancement activities—have on Bonneville's rates and costs, which are directly related to its competitive position. In our report we state that the costs of protecting fish and wildlife and mitigating damage to fish affected by the construction and operation of the Federal Columbia River Power System are a consideration in the revenue requirements analysis that underlie Bonneville's rates. In addition, we state that the estimated range of funding for these activities is from $438 to $721 million annually for fiscal years 2002 through 2006. To the extent that these expenditures go toward mitigating environmental harm not caused by the production of power, they provide public benefits. However, to the extent that these expenditures are undertaken to mitigate environmental harm caused by producing power, the costs are analogous to the environmental mitigation costs incurred by any other utility. We did not assess whether Bonneville's expenditures to mitigate environmental harm caused by producing power are greater or lesser than the environmental mitigation expenditures of other utilities.

    In addition, we disagree with Bonneville's statement that we do not consider the irrigation costs that Bonneville must recover through rates. Our report clearly states that two of the PMAs—Bonneville and Western—are required to set rates at levels sufficient to repay certain nonpower costs, such as irrigation, that the Congress has assigned to power users to repay. Further, our report states that as of

September 30, 1998, approximately $863 million in irrigation costs had been allocated for repayment through power revenues at Bonneville and that $25 million (3 percent) of that amount had been repaid. We have also added a statement to the report acknowledging Bonneville's requirement to provide power to residential and small farm consumers of investor-owned utilities.

Any disadvantages cited by Bonneville in its letter are overshadowed by the cost advantages we describe in our report. Our report shows that Bonneville's investment in utility plant per megawatt of generating capacity and average revenues per kilowatthour for wholesale sales are relatively low compared to IOUs and POGs.

18. We disagree. The objectives of our review did not include providing detailed information on every legislative requirement followed by Bonneville or the other three PMAs. We did not delineate all the requirements contained in the Northwest Power Act or the other acts we cited, such as the Reclamation Project Act of 1939 and the Flood Control Act of 1944. Our report acknowledges that Bonneville's ratesetting process is unlike that of the other three PMAs.We have added language to clarify that the primary statute governing Bonneville's ratesetting procedures is the Northwest Power Act. In addition, we discuss Bonneville's rate development process separately and provide a separate flowchart that depicts Bonneville's process under the Northwest Power Act. To achieve our reporting objectives, we appropriately focused on the three PMAs' power repayment studies and Bonneville's revenue requirement study, which identify the PMAs' costs to be recovered through rates and revenue requirements. The legislative requirements affecting Bonneville's revenue requirements are reflected in its revenue requirement studies.

19. We developed the flowchart depicting Bonneville's ratesetting process based on discussions with Bonneville officials. We have incorporated into this final report Bonneville's subsequent minor edits and clarifications.

20. Our report discusses the Energy Policy Act of 1992 and FERC's role in ratesetting sufficiently to achieve the objectives of our review.

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