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2003 Safety-Net Cost Recovery Adjustment Clause Initial Proposal

Direct Testimony

SN-03-E-BPA-06 REVENUE RECOVERY

March 2003

BONNEVILLE
POWER ADMINISTRATION

INDEX

TESTIMONY OF

VALERIE A. LEFLER, RONALD J. HOMENICK AND DAVID M. STEELE

Witnesses for Bonneville Power Administration

SUBJECT: Revenue Recovery Study

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SUBJECT: REVENUE RECOVERY STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Valerie A. Lefler and my qualifications are contained in SN-03-Q-BPA-11.

A. My name is Ronald J. Homenick and my qualifications are contained in SN-03-Q-BPA-06.

A. My name is David M. Steele and my qualifications are contained in SN-03-Q-BPA-25.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the development of total spending level projections for the generation function of the Federal Columbia River Power System (FCRPS). Overall, our testimony addresses significant changes in the projections, assumptions, and methods used to determine spending levels and to demonstrate cost recovery since Bonneville Power Administration's (BPA) May 2000 Final Proposal. The documents covered by this testimony consist of the Revenue Recovery Study, which is contained in the SN-03 Study, SN-03-E-BPA-01, Chapter 3, and the documentation for the Revenue Recovery Study, which is contained in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 3.

Q. How is your testimony organized?

A. Section 2 explains why BPA is producing a revenue recovery study rather than a revenue requirement study. Section 3 addresses changes to forecasted expenses since the May 2000 Proposal. Section 4 describes the net revenue gap. Section 5 describes the assumptions in the repayment studies. Finally, Section 6 addresses potential changes that may be made in the Final SN-03 Rate Proposal.

Section 2. Explanation of Revenue Recovery Study

Q. Why have you done a Revenue Recovery Study rather than a Revenue Requirement Study?

A. The purpose of the Revenue Recovery Study is to demonstrate cost recovery in the remainder of the rate period from the revenues that result from the SN CRAC modifications. BPA is not reestablishing the base rates in this process, redefining the rate period, or establishing a new repayment schedule. The criteria for triggering the SN CRAC and the solutions to the problem are driven by parameters defined by BPA in the June 2001 Supplemental Proposal rather than through the ordinary means specified in Department of Energy repayment policy. Because of these factors, BPA determined that a traditional revenue requirement study was not necessary. The intent of the abbreviated study is to document the generation expenses and cash requirements and demonstrate the adequacy of the modified power rates for FERC.

Section 3. Changes to Forecast of Expenses

Q. How has BPA's forecast of expenses changed since the revenue requirement was developed for BPA's May 2000 Proposal?

A. The forecast at the conclusion of BPA's May 2000 Proposal process included average annual spending levels of $2,366 million for the generation function in fiscal years (FY) 2004-2006, the period covered by this SN-03 proposal. *See* Revenue Requirement Study, WP-02-FS-BPA-02. Total spending levels in this SN-03 rate proposal include average annual expenses of $3,038 million, a total increase of about $1.6 billion over the FY 2004-2006 period. A significant portion of this amount is due to augmentation costs and is intended to be recovered through the LB CRAC. Over the FY 2002-2006 period, PBL's non-power purchase and augmentation costs increased by about $1.5 billion, with about $500 million in offsetting revenues. *See* Keep, *et al,* SN-03-E-BPA-04, and the

SN-03 Study, SN-03-E-BPA-01, Chapter 3. For the FY 2004-2006 period, these costs increased by about $1.05 billion.

Q. Please describe the reasons for the increase in average annual expenses over the May 2000 Proposal forecasts.

A. There are several major reasons for the increase in average annual expenses. These include (1) increases in financial benefits provided to investor-owned utilities (IOU) for their residential and small-farm customers; (2) increased operations and maintenance (O&M) costs for the hydro system; (3) increased O&M costs for the Columbia Generating Station (CGS) nuclear plant; (4) increased Federal depreciation, amortization, and net interest expenses; and (5) increased BPA power-related internal operating costs.

Q. Did these costs rise substantially from FY 1996-2001 levels?

A. Some have increased and some have not. Compared to actual costs prior to FY 2002, certain of these costs have not increased at all, for example in the case of power-related internal costs. However, the May 2000 Proposal assumed significant decreases in these areas, based on the Regional Review and Cost Review, that have not materialized. *See* SN-03 Study, SN-03-E-BPA-01, Chapter 3.

Q. Please explain the increased costs for the IOU benefits.

A. Benefits to the IOUs are $370 million higher over the FY 2002-2006 period than assumed in the May 2000 Proposal. This results in an annual average increase of $74 million per year. Payments to IOUs for their residential and small-farm customers from 1997 to 2001 averaged about $70 million per year and a similar amount of financial benefits was included in expenses in the May 2000 Proposal. In the June 2001 Supplemental Proposal, BPA included an additional $74 million per year increase in the IOUs' benefit level, bringing the total financial payments to IOUs to $144 million per year. Customers advocated, and BPA agreed to, this increase in benefit levels because the forecast of prices in the wholesale power market had increased greatly from the time BPA established the benefit level in May 2000. Given assumptions about market prices and the level of benefits, this increase appeared reasonable at the time.

Q. Why have hydro system O&M costs increased, and by how much?

A. O&M costs for Federal hydropower and other generating projects are $120 million higher than the May 2000 Proposal projections for FY 2002-2006, averaging $24 million per year. Two major drivers of this increase are the change in the percentage allocation to power purposes at the Columbia Basin Project (Grand Coulee Dam) from 70 percent to 92 percent (about $6.6 million per year), and the addition of the Green Springs, Elwah, and Glines projects ($2.6 million per year). Additionally, after completion of the May 2000 Proposal, a joint assessment by BPA, the Army Corps of Engineers (Corps), the Bureau of Reclamation (Reclamation), and Energy Northwest (ENW) compared Federal hydro system O&M costs, along with associated capital costs, against other hydro systems. Performing this type of evaluation ensures that BPA is closely monitoring investment levels vis-à-vis other comparable hydro systems. Based on these efforts, BPA believes the O&M expense projections for the Corps and Reclamation hydro projects were at such a low level that availability and future reliability of the projects likely would be degraded. Hence, over the FY 2002-2006 period, these O&M costs are assumed to be higher to reflect the effort to maintain the projects prudently and avoid adverse consequences. Additionally, security costs totaling $6.3 million annually (or $31.5 million in total over the rate period) as a result of terrorist attacks against U.S. targets on September 11, 2001, have been added. The additional security was not contemplated in the May 2000 Proposal.

Q. Why are CGS O&M and capital costs higher?

A. Actual and projected CGS O&M costs are $147 million higher than those in the May 2000 Proposal in total, averaging over $29 million higher per year. In the mid-1990s, ENW substantially reduced the cost of operating the CGS. BPA assumed in the May 2000 Proposal that the level of cost reductions experienced in the mid-1990s would continue through the FY 2002-2006 period. However, after significant cost-cutting and deferred maintenance in the late 1990s, the CGS increased capital investments and expenses to replace obsolete equipment, perform major maintenance activities to address projects deferred over the last 3 to 5 years, cover increased costs associated with onsite spent fuel storage, and cover costs related to increased security to implement measures required by the Nuclear Regulatory Commission after September 11, 2001. In particular, security costs as a result of September 11, 2001, have added about $4 million annually (or $20 million in total over the rate period) to the current forecast of expenses.

Q. Why are Federal net interest and depreciation higher?

A. Debt service is $60 million higher than the May 2000 Proposal forecasts in total for FY 2002-2006, averaging $12 million per year. Net interest expense has increased primarily because of lower-than-forecasted cash reserves in the Bonneville Fund, resulting in reduced interest income. In addition, Federal projects depreciation, specifically for conservation, is higher, reflecting increased conservation capital spending. There was no Conservation Augmentation (ConAug) capital in the May 2000 Proposal. (The ConAug capital program is discussed later in more detail later in this testimony.)

Q. Are any other expenses higher?

A. Yes. BPA's internal costs supporting the power function are $279 million higher than May 2000 Proposal forecasts for the FY 2002-2006 period, with an average increase of $56 million per year. Internal operating costs supporting BPA's power function are the costs that sustain operation and administration of many BPA programs. In the May 2000 Proposal, estimates for these expenses were largely based on the Comprehensive Review and the Cost Review recommendations. *See* SN-03 Study, SN-03-E-BPA-01, Chapter 3.

The Comprehensive Review and the Cost Review envisioned a dramatically shrinking role for BPA and a very simple wholesale power market and operating environment with less than half the number of "Full-Time Equivalent" (FTE) employees currently operating BPA's power function. The implication of these reviews was that the fundamental relationship between BPA and its long-term power customers would change significantly and that BPA's traditional customer support services would no longer be needed. For instance, the Comprehensive Review assumed Northwest customers would not exercise their statutory right to obligate BPA to meet their entire net requirement, even if the total sales exceeded total output of the Federal system. Further, the Cost Review estimates were predicated on greatly simplified billing, scheduling, and inventory systems. Similarly, the Cost Review contemplated Northwest Power Planning Council costs to be 20 percent lower than they are today.

Changes in the industry, however, have required significant personnel and information technology investments just to keep pace with the current complex wholesale power market and scheduling environment. While staffing costs have been shrinking in many areas, such as account executives and their support staff, rates staff, market research, load forecasting, resource planning and development, and conservation, BPA's role has expanded in major ways. This has led to offsetting increases in costs and staffing in other areas, especially in the areas of 24-hour, 7-days-per-week scheduling, information technology, and trading floor activities support.

Also included in the category of internal costs is $25 million of increased conservation expense. This reflects the increase in the conservation effort that began with the West Coast energy crisis over the 2000-2001 period.

Q Are there additional changes in expense forecasts?

A. Yes. There is an additional expense, a "bad debt" expense, arising from the California Independent System Operator/Power Exchange (ISO/PX) and BPA's direct service industrial (DSI) customers. A bad debt is BPA's credit exposure due to unpaid power bills. BPA still is owed about $80 million by the California ISO/PX. Of this amount, BPA made an accounting adjustment to its net revenues in 2002 of around $25 million to reflect the risk that BPA may never be paid this amount. It is anticipated that BPA's refund obligation will increase based upon recent decisions at FERC. This will impact BPA's bad debt expense for ISO/PX obligations. To the extent that these amounts are known, BPA will update this amount. Additionally, BPA has take-or-pay contracts that obligate the DSIs to pay liquidated damages on IP power that is not purchased (curtailed) forcing BPA to sell the curtailed amount in the surplus market when the market value is less than the IP value. The DSIs are obligated to pay BPA the difference under those circumstances so that BPA is made whole. BPA is at risk of not being paid about $30 million of FY 2002 liquidated damages due to the poor financial condition of some DSIs and the bankruptcies of others. BPA is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

Q. What is BPA doing to control its costs?

A. BPA has gone to its employees, Federal partners, customers, constituents, ENW, the Northwest Power Planning Council, and others to seek additional cost savings. At this point, BPA has identified $350 million in cost savings, expense deferrals and other actions. These savings are largely included in this SN-03 proposal.

Q. *You say "largely included." Are there some that are not included?*

A. Yes. $20 million of these expense reductions associated with BPA internal operating costs were inadvertently not included. They will be included in the Final Study.

Q. What action is BPA taking to reduce internal costs?

A. Of the above-noted savings, $140 million has come from BPA's internal operating costs charged to its power function. BPA has nearly completed the process of bringing these

FY 2003-2006 net operating costs down to FY 2001 actual levels and is bringing several cost categories down below FY 2001 actual levels. BPA plans to hold costs at or below 2001 levels for the remainder of the rate period, net of offsetting revenue increases expected to be achieved as a result of making certain expenditures.

Some specific actions the Power Business Line has taken are:

- Reduced travel expenses by approximately half from 2001 actuals (will save over $1.5 million over 4 years compared to 2001 actuals).
- Reduced training expenses approximately by two-thirds from 2001 actuals (will save almost $1 million over 4 years compared to 2001 actuals).
- Reduced monetary awards to staff approximately 95 percent from 2001 actuals (will save over $7 million over 4 years compared to 2001 actuals).
- Eliminated retention allowances for critical employees (will save over $3.5 million over 4 years compared to 2001 actuals).
- Cut materials and equipment expenses significantly from 2001 actuals (will save over $25 million over 4 years compared to 2001 actuals).
- Cut research and development spending from 2001 actuals and terminated fuel cell program ($26.6 million reduction in Energy Efficiency and Conservation programs, including Market Development, Technology Leadership/Energy Web, Legacy Conservation contracts, and Market Transformation).
- Reduced rates staff, load forecasting staff and power account executives by over 25 percent over the last 5 years.
- Reduced communications and community outreach programs from 2001 actuals.
- Cut nuclear oversight staff due to improved performance of the CGS in the 1990s – reduced to 7 employees from 13.

Additionally, BPA has placed a moratorium on outside hires (with limited exceptions), offered early retirement to reduce employment levels, and cancelled or deferred major information technology development projects.

Q. What is the source of the fish and wildlife costs included in BPA's SN-03 proposal?

A. The forecasted costs for BPA's fish and wildlife program are $139 million per year for expenses, and $36 million per year for capital. These amounts are based on the Action Agencies' Implementation Plan, described in Keep, *et al*., SN-03-E-BPA-04, and are expected to meet the requirements of the Biological Opinions and the Northwest Power Planning Council's Fish and Wildlife Program.

Q. How do they compare to the costs included in the May 2000 Proposal?

A. These values are the same as the annual average of the expected values for FY 2004-2006 used in the May 2000 Proposal. In the May 2000 Proposal, the expense level was the mid-point of a wide range of potential costs.

Q. Are there any other changes that are reflected in the current PBL cost structure?

A. Yes. There were two events in FY 2001 involving Reclamation projects. At Columbia Basin (Grand coulee Dam), Reclamation completed an examination of project purposes that resulted in a reallocation to power of plant previously associated with irrigation (directly as irrigation or indirectly as common general plant). As a result, the capital investment at the project for which power rates are responsible increased by $69.226 million, and there was a decrease in irrigation assistance of $98.345 million. This reallocation also causes a corresponding increase in the O&M associated with power purposes. In addition, Green Springs (Rogue River Irrigation Project), a project in southern Oregon, with investment of $11.17 million, was added to the FCRPS.

Q. How has the increased investment been reflected in the cost forecasts?

A. For both of these changes in power investments, new appropriated repayment obligations were added to the repayment database as if these investments were new Congressional appropriations in FY 2001. As such, the obligations were assigned due dates 50 years from that date (2051), and given interest rates of 5.75 percent, reflective of that repayment term. Consequently, interest expense projected for the rate period is increased from these events. Depreciation expense also is increased from these additional investments.

Q. Are there impacts elsewhere in this SN-03 proposal?

A. Yes. The reallocation to power purposes of plant at Columbia Basin has the effect of reducing the overall percentage of FCRPS cost to non-power purposes from 27 percent to 22.3 percent. This affects the 4(h)(10)(C) credit by reducing the percentage applied to qualifying costs to 22.3 percent to arrive at the allowable credit.

Q. Are there any other financial changes?

A. Yes. The ConAug capital program, which was not reflected in rate period costs in the base rates, now includes actual (FY 2002) and forecasted amounts, which are reflected in the current interest expense and conservation amortization forecasts. More importantly, there has been a change in accounting policy for these investments that departs from the accounting treatment of the legacy conservation investments. The policy for ConAug deviates from the existing 20-year conservation life. Because the intent of these investments is to provide benefits only during the 10-year Subscription Power Sales Contract term, FY 2002-2011, the asset life reflects that time period rather than an average or composite life. In other words, an investment in 2002 is amortized over 10 years, an investment in 2003 is amortized over 9 years, and so on. All Treasury bonds associated with funding these investments, similarly, bear a maturity no later than 2011.

Section 4. Net Revenue Gap

Q. In the Testimony of Keep, et al., SN-03-E-BPA-04, it is explained that one criterion of BPA's SN-03 proposal is the goal of achieving zero net revenues over the rate period. What does this mean?

A. Achieving zero net revenues over the rate period means raising rates such that the net revenue gap of $920 million for the FY 2002-2006 period, based on actual and forecasted PBL revenues and expenses, is eliminated. *See* Keep, *et al*., SN-03-E-BPA-04. The income statements which show the $920 million gap are included in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 3.

Q. What assumptions underly the $920 million gap?

A. The $920 million assumes actual and projected revenues consistent with a maximum FB CRAC and no SN CRAC. *See* Hirsch, *et al.*, SN-03-E-BPA-05. The expenses assume the costs and cost cuts described in section 3 of this testimony. The ENW debt service is that included in the May 2000 Proposal, consistent with the FB CRAC net revenue calculation. The net revenues also do not include the mark-to-market adjustment called for by the Statement of Financial Account Standard (FAS) Number 133, again consistent with the FB CRAC net revenue calculation.

Section 5. Repayment Study Issues

Q. What assumptions are used in the Federal amortization payments, gross interest expense, and depreciation expense included in the Revenue Recovery Study?

A. The interest forecasts have been updated and incorporated. *See* Documentation, SN-03-E-BPA-02, Chapter 3. The Federal projects depreciation is based on capital projections from November 2002 and actual data from FY 2001. Repayment studies have been run using those capital projections and similar vintage interest rate forecasts. In this SN-03 initial proposal, the repayment studies are used primarily to forecast

Federal interest expense. The schedule of planned Federal amortization remains that which was filed with FERC, June 29, 2001.

Q. *Does BPA propose changing planned amortization payments?*

A No, BPA is not proposing any changes to the schedule for the remainder of the rate period.

Q. *What changes have been made in the Repayment Program since BPA's May 2000 Proposal?*

A. Since BPA's May 2000 Proposal, BPA has implemented new repayment model software, the Ferrand Jordan Repayment Model. The old repayment model was written in Fortran, and it was becoming increasingly difficult to find staff proficient in Fortran programming to modify and keep the program running. Additionally, the old model was not developed to accommodate scenario analysis (analyzing outcomes based on differing assumptions), which has become a critical need at BPA. The new Ferrand Jordan model provides two major benefits: it offers more flexibility within the optimization goal of solving for the lowest minimum revenue level that meets all repayment obligations with interest; and it provides an interface with all of the benefits of a Windows-based approach.

The new Ferrand Jordan model offers two basic modes of operation:

1) The first mode uses the same equations used in the FORTRAN repayment model, but uses a "simplex" calculation method of linear programming rather than binary iteration to optimize. This changes the order in which bonds are scheduled to be paid to more thoroughly minimize the revenue needed to repay the debt service.

2) The second mode is a full replication of the original Fortran model. It includes the portion of the program that determines which bonds to call based on the highest coupon adjusted for the call premiums. *See* May 2000 Final Proposal Revenue Requirement Study, WP-02 FS-BPA-02, Appendix A; and

Revenue Requirements Study Documentation, Volume 2, WP-02 FS-BPA-02B, for further explanation of the Repayment Model.

Q. Which mode does BPA use to produce rate case amortization schedules?

A. In the repayment study, which is the basis for the interest calculation, and in all other regulatory runs, BPA uses the second mode since the first mode ignores the "priority of payments" required by law in the Federal Columbia River Transmission System Act, as amended, and by Department of Energy Policy RA 6120.2 (the "priority of payments" language requires BPA to pay all other creditors before repaying its debt to the Treasury). Mode one is used only for scenario analysis and debt planning.

Q. Does this new model introduce any changes from the old model?

A. Yes, there are two changes. First, the Ferrand Jordan model discontinues the practice of rounding all numbers to the nearest $1,000. Numbers generated by the Ferrand Jordan model are not rounded, which gives a greater degree of accuracy to the results. The second change between the models is in the way the input data is formatted and manipulated. Instead of producing and maintaining separate database files (in the form of a text file) for each year (15 files for a 5-year run), the new model now keeps all obligations in only three databases—a "historical Federal" database, a "projected Federal" database, and a "third party" database. This saves a significant amount of time, and significantly reduces input errors, while facilitating error tracking.

Section 6. Anticipated Adjustments to Final Rate Proposal

Q. Are there any anticipated adjustments that may be included in the Revenue Recovery Study for the Final Rate Proposal?

A. Yes. BPA will include any changes in expense forecasts, including any additional cost savings, that BPA identifies prior to development of the Final Study. Any changes in fish and wildlife cost forecasts, based on recommendations from the Regional Forum and the Northwest Power Planning Council, will be reflected.

Interest and depreciation forecasts will be updated to reflect any new capital forecasts and actual data. The Corps and Reclamation budget data may be updated. In addition, BPA recently received revised irrigation assistance investments (*see* Documentation, SN-03-E-BPA-02, Chapter 3), which will be reflected in the Final Rate Proposal repayment study. In the Final Rate Proposal, BPA may include capitalization of investment in land acquisition for fish and wildlife, provided such costs exceed $1 million, and if such investment provides a creditable/quantifiable benefit against a defined obligation for BPA.

In 2002, as part of its capital strategy, BPA issued bonds with terms considerably shorter than the service lives of the associated assets. Rather than taking advantage of the lower interest rates associated with 3- and 4-year terms, these bonds were issued specifically to accommodate the use of proceeds from sources other than current revenues to make amortization payments above the repayment schedule established in this proposal. As a result, BPA may adjust the terms and corresponding interest rates to longer maturities that are more reflective of actual bond issuance practices so that the base schedule is not artificially increased in the Final Rate Proposal repayment study.

Q. *Does this conclude your testimony?*

A. Yes.