WP-85 Wholesale Power Rate ROD, WP-85-A-02

# 1985 WHOLESALE POWER RATE AND TRANSMISSION RATE ADJUSTMENT PROCEEDING ADMINISTRATOR'S FINAL RECORD OF DECISION

BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

MAY 1985

## TABLE OF CONTENTS

[page 1]

# I. INTRODUCTION

## A. Procedural History of the Rate Proceeding

On July 25, 1984, BPA published notices of intent to revise its wholesale power and transmission rates, 49 FEDERAL REGISTER 3007 and 3009, respectively. BPA's initial proposals for revised rates were issued on September 6, 1984, 49 FEDERAL REGISTER 35177 and 35212. The proposed effective date for the rate increase is July 1, 1985, subject to the interim approval of the Federal Energy Regulatory Commission (Commission).

In accordance with section 7(i) of the Pacific Northwest Electric Power and Planning and Conservation Act (the Northwest Power Act), 16 U.S.C. §839e(i), an evidentiary hearing on the proposed rate adjustments was conducted by Judge Seymour J. Wenner, Judge Dean F. Ratzman, and Judge William J. Sweeney, Hearing Officers. Forty-seven interventions were filed by publicly owned and investor owned utility customers, direct service industrial customers, State agencies, public interest groups, and Congressman James Weaver. Judge Wenner commenced the proceedings with a prehearing conference on September 24, 1984, at which he issued special rules of practice and discussed procedural schedules with the parties. Thereafter, Judge Wenner issued a procedural schedule on October 8, 1984.

BPA's initial proposal consisted of the written testimony, studies, and exhibits of 30 witnesses. The parties filed their initial direct testimony on November 7, 1984. BPA filed supplemental testimony on November 20, 1984. Parties filed supplemental testimony on December 13, 1984. Rebuttal and surrebuttal testimony on certain discrete issues (7(c)(2) industrial margin and nonfirm energy issues) were filed on various dates in December 1984 and January 1985. Motions to strike BPA's prefiled testimony and parties' prefiled testimony were made on scheduled dates in October, November, and December 1984, following the respective filings of BPA's and parties' direct, supplemental, and rebuttal testimony. Judge Wenner ruled on all motions to strike prior to the beginning of cross-examination on January 7, 1985, at which time Judges Ratzman and Sweeney replaced Judge Wenner as Hearing Officers.

BPA responded to 1,990 data requests concerning all aspects of its initial proposal. Eighteen days of clarification sessions, transcribed oral discovery comprising some 2481 pages, were conducted between September 27, 1984 and December 20, 1984, on both BPA's and the parties' pre-filed testimony.

Cross examination began on January 7, 1985, and extended through February 1, 1985. Concurrent sessions of cross-examination were conducted by Judge Dean F. Ratzman and Judge William J. Sweeney, who ruled on all subsequent motions and related procedural matters. There were a total of 15 days of cross examination, of which 10 days contained concurrent sessions before both judges, comprising a total of 4092 transcribed pages.
[page 2]
Initial briefs were filed by nearly all parties on February 21, 1985.

Parties presented oral argument on March 4, 1985, before a panel comprised of Peter Johnson, Administrator; Edward Sienkiewicz, Assistant Administrator for Power and Resources Management; and Harvard Spigal, General Counsel. In addition, other BPA managers observed the parties' oral presentations.

For interested persons who did not wish to become parties to the formal evidentiary hearings, BPA conducted a series of eight field hearings during October 1984 in Portland and Eugene, Oregon; Seattle, Spokane, and Richland, Washington; Burley, Idaho; Jackson, Wyoming; and Missoula, Montana. A second set of field hearings was conducted during January 1985. BPA has also received 614 written comments. Transcripts of the field hearings and the written comments become part of the record on which the Administrator bases his decisions.

On March 19, 1985, BPA issued its Evaluation of the Record. This document was intended to present the BPA Administrator's draft decisions on each of the issues raised in the 1985 rate proceedings, based on his review of the evidence, the oral arguments, and the initial briefs. However, these draft decisions were not final in either the legal or the practical sense. The Administrator has reconsidered his decisions based on the parties' reply briefs, filed on April 1, 1985.

This Record of Decision is divided into the following two sections: (1) comments by the parties which were generally of a specific and technical nature; and (2) comments of the participants which were of a more general nature. The parties' comments are evaluated in eight chapters corresponding with the rate adjustment process; preliminary issues concerning BPA's loads and resources, revenue uncertainty, and cost classification; the Revenue Requirement Study that determines BPA's revenue requirements; the Marginal Cost Analysis that determines BPA's incremental costs on a seasonal, daily, and hourly basis for new generation and transmission load; the Cost of Service Analysis that identifies the average costs associated with providing BPA's services; the section 7(c)(2) Industrial Margin Study that describes the calculation of the "typical margin"; the section 7(b)(2) Rate Test Study; the Wholesale Power Rate Design Study; and the Transmission Rate Design Study. These last two chapters describe the ratesetting process and other integral studies used in revision of the specific rate structures. Chapter X discusses the Impact Analysis and Chapter XI summarizes the major issues presented by 614 letters from participants.

Within the individual chapters addressing the comments of the parties specific issues are identified. The evaluation of each issue is divided into three sections: (1) summary of the positions, which briefly states the BPA proposal and the positions the parties have taken on the record concerning the issue; (2) evaluation of the positions, which discusses the various arguments on each issue and presents BPA's evaluation of the arguments; and (3) the decision of the Administrator on the issue. The chapter addressing the comments of the participants has a similar structure. The participants'
[page 3] comments have been aggregated into eight general issues that reflect the concerns expressed by the public. Where the issues identified by the participants overlap those raised by the parties, a general evaluation is provided and reference is made to the more technical evaluation contained in the earlier portion of the document.

The Appendix includes a list of party abbreviations used throughout the Record of Decision, a list of party witnesses and representatives, a list of participants who sent comments on the rate adjustment, and the wholesale and transmission rate schedules and general provisions.

To simplify a cite to any transcripts, the "STR" indicates the transcripts of hearings before Judge Sweeney, whereas "TR" indicates the transcripts of hearings before Judge Ratzman.

## B. Legal Requirements

### 1. General Rate Guidelines

Section 6 of the Bonneville Project Act, 16 U.S.C. §832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers to be effective upon confirmation and approval by the Commission. This section directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the Bonneville Project Act, 16 U.S.C. §832f, provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the capital investment over a reasonable period of years.

The Federal Columbia River Transmission System Act (Transmission Act), 16 U.S.C. §838, contains requirements similar to those of the Bonneville Project Act. The Transmission Act provides three specific guidelines for the establishment of rates by the Administrator: (1) to set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) to set rates with regard to the recovery of the cost of producing and transmitting electric power, including the amortization of the capital investment allocated to power over a reasonable period of years; and (3) to set rates at levels which produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission Act, including amounts required to establish and maintain reserve accounts.

The Flood Control Act of 1944 directs that the sale of electric power from certain reservoir projects take place "in such a manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. 825s. The Act also provides that "rate schedules should be drawn having regard to the
[page 4] recovery … of the cost of producing and transmitting such electric energy." 16 U.S.C. 825s.

The Northwest Power Act, 16 U.S.C. §839e, provides additional rate guidelines. Section 7 of the Northwest Power Act 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. The rates are to be set so that BPA recovers, over a reasonable period of years, 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 out of power revenues). Other rate directives within section 7 describe how rates for individual customer groups may be derived. Section 7 also prescribes formal ratesetting procedures for BPA.

### 2. Confirmation and Approval

The Northwest Power Act specifies in section 7(a)(2) that rates become effective upon final or interim approval by Federal Energy Regulatory Commission. The Commission must review the rate proposal to determine that (1) rates are sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; (2) rates are based on BPA's total system costs; and (3) transmission rates equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system. Pursuant to section 7(i)(6) of the Northwest Power Act, the Commission has promulagated rules found at 18 C.F.R. Part 300 establishing procedures for the approval of BPA rates.

[page 5]

## II. PRELIMINARY ISSUES

### A. Introduction

The issues discussed in this chapter are treated separately because their resolution affects other issues throughout BPA's ratesetting process. The chapter first deals with issues related to BPA's load forecasts, specifically the forecasts of DSI and generating public loads. Second, BPA's proposed level of conservation expenditures is discussed. The third section discusses BPA's decision to use 1939 water conditions in setting its rates, as a way to deal with revenue uncertainty. The final set of issues discusses BPA's classification of costs between capacity and energy.

**B. Load Forecasts**

For the 1985 rate proposal, methods introduced in the 1983 wholesale power rate adjustment proceedings are used to a large extent to forecast the loads of BPA's major customer groups. Each forecast is briefly discussed below and then is expanded upon when specific issues are considered. The non- and small-generating public utility load forecast is based on econometric methods. The aluminum DSI forecast is based on a model that simulates the short-run economics of aluminum company potline operations, although longer-term aluminum industry decisionmaking is also considered. The forecast for nonaluminum DSIs is based on industry specific analysis using primarily an econometric approach. The generating public utility load forecast is based on an econometric model developed by BPA. The forecast of investor-owned utilities' total loads is based on the individual utilities' 1984 submittals to the Pacific Northwest Utilities Conference Committee (PNUCC). Individual private utility forecasts are the basis of the IOU residential exchange forecast. The forecast of Federal agency loads is developed by BPA area offices in cooperation with each agency. Finally, the U.S. Bureau of Reclamation "reserved energy" load forecast is provided by the USBR.

Forecasts of all customer groups, with the exception of the DSI forecast, remained the same from the initial to the final rate proposal. The updated DSI forecast was adjusted to remove the loads of one regional aluminum smelter that closed after the initial proposal, as well as the loads of one firm that had requested BPA service as a nonaluminum DSI but subsequently signed a long-term power sales contract with a local utility. In addition, the forecasted price of aluminum used as an input to BPA's aluminum industry forecasting model was revised from the initial to the final rate proposal.
[page 6]

**1. DSIs**

Until the 1982 rate filing, BPA forecasts of DSI loads were based solely on contract demands contained in each industrial customer's power sales contract with BPA. These contracts were used as the justification for including maximum contract amounts in forecasts of DSI loads, even though the DSIs (collectively and individually) did not always use their total contract demands.

Under the Northwest Power Act, new power sales contracts were executed with the DSIs that include provisions for both contract and operating demands. For the 1982 wholesale power rates, BPA based its DSI load forecast primarily on projected operating demands supplied by the DSIs themselves. Subsequent depressed economic conditions led to curtailed levels of production, and as a result DSI loads during OY 1982-83 were well below forecasted levels. The forecasts based on operating demands, which were used in BPA's rate decisions, exposed BPA to significant underrecovery of revenues. As a result of these circumstances, BPA determined for the 1983 wholesale power rates that the DSI forecast should be based on forecasted operating levels to represent the best estimates of projected near-term DSI loads.

The logic, methodology, and inputs to the DSI load forecasting process developed during the 1983 rate filing process were used to prepare the forecast presented in BPA's initial testimony in this rate adjustment proceeding. Hoffard and Moorman, BPA, E-BPA-10, 16-33.

A supplemental forecast also was developed during the course of the 1985 rate filing. Hoffard and Moorman, BPA, E-BPA-10S. This supplemental forecast retains the basic methods of the earlier forecast, but it incorporates updated data on the price of aluminum, conditions in world aluminum markets, and developments affecting specific regional smelters.

**a. Aluminum DSIs**

**Issue #1**

*Are BPA's forecasts of aluminum prices reasonable?*

**Summary of Positions**

For the 1985 rate filing, BPA relied primarily on Chase Econometrics for its base case forecast of the market price of aluminum. To corroborate Chase's forecasts, BPA has also examined aluminum price forecasts prepared by Commodities Research Unit (CRU), Resource Strategies, Inc. (RSI), and Stuart Spector.

In its initial testimony relating to forecasted loads, BPA used Chase's latest forecast of the U.S. market price of aluminum from the March 1984 *World Aluminum Outlook*. Moorman and Hoffard, BPA, E-BPA-10, 26. This forecast
[page 7] projected prices to reach 85 cents/lb. by mid-1985, 93 cents/lb. by mid-1986, and $1.00/lb. by mid-1987. *Id*. at 24. Beginning in early 1984, however, aluminum prices deteriorated drastically. Consequently, BPA updated its forecast of aluminum prices in supplemental testimony using Chase's August 1984 *World Aluminum Outlook*. Moorman and Hoffard, BPA, E-BPA-10S, 5. This forecast predicted prices to average 71 cents/lb. in 1985, 79 cents/lb. in 1986 and 77 cents/lb. in 1987.

BPA recognizes the significant dependence of forecasted DSI loads on the aluminum prices assumed in the Aluminum Smelter Model (ASM). To account for the uncertainty and volatility in aluminum prices, BPA developed four alternative load scenarios based on alternative price forecasts. Moorman and Hoffard, BPA, E-BPA-10S, 9. These four scenarios consist of one optimistic and three pessimistic price and load forecasts.

NWU took issue with BPA's aluminum price forecasts and outlined "a method for evaluating what to expect for the price of aluminum over the medium term." Wolverton, NWU, E-NU-02, 1. NWU claims that "the aluminum companies that have been putting up plants at costs of 75-85 cents a pound expect the prices to average *at least* 75-85 cents a pound." *Id*. at 5. This conclusion is based primarily on a review of the production economics of the Portland (Victoria, Australia) aluminum smelter owned by Alcoa. McCullough, NWU, E-NU-03. NWU asserts that 1) the average total cost from the Portland smelter will be approximately 86 cents per pound; 2) the decision to construct the smelter establishes that the company constructing the smelter expects that prices over the long run will be at least sufficient to produce a profit on the facility; and 3) therefore, BPA should give substantial weight to this cost as an indication of expected price. Initial Brief, NWU, B-NU-01, 44-45.

**Evaluation of Positions and Decision**

The only empirical evidence relied upon by the NWU to reach its conclusion that aluminum prices will average at least 75-85 cents/lb. is the report on the Portland smelter. Wolverton, NWU, STR 450-455. This limited evidence does not demonstrate that the economics of the Portland smelter are representative of the economics of other new smelters. For instance, numerous significant features of the Portland smelter and its financing are unique to that plant. These features include substantial loans made by the government of Victoria to Alcoa, the payment of approximately $40 million by the State of Victoria to Alcoa for a share of Alcoa's assets, the forgiveness of "delay payments" from Alcoa to the State Electric Commission of Victoria totalling as much as $160 million, and the impact of undisclosed alumina contract terms. Hoffard and Moorman, BPA, E-BPA-51R, 12. BPA's forecast of aluminum prices cannot be based upon the circumstances of one smelter, especially in light of the unique circumstances surrounding that plant.

Moreover, even if the costs of the Portland smelter do reflect Alcoa's price expectations from that particular plant (which has not been demonstrated), they would not necessarily reflect the price expectations of other aluminum companies. NWU even acknowledges that "the firm's expectations
[page 8] of price may be erroneous when viewed from a better perspective." Wolverton, NWU, E-NU-02, 3; Hoffard and Moorman, BPA, E-BPA-51R, 12.

BPA's aluminum price forecasts reflect significant concern about the uncertainty and volatility of aluminum prices and their impact on DSI loads. Hoffard and Moorman, BPA, E-BPA-51R, 16; E-BPA-10, 23-24. NWU has not presented evidence indicating that their price forecasts take these factors into account. The forecasts prepared by Chase Econometrics, which BPA has carefully examined, are supported by well-documented and detailed world aluminum supply/demand forecasting models. BPA continues to rely on the Chase Econometrics forecast, corroborated by other available forecasts, to establish ranges of uncertainty and market volatility. Accordingly, BPA believes its forecasts of aluminum prices are eminently reasonable.

**Issue #2**

*Are BPA's estimates of PNW smelter costs, compared to costs of smelters elsewhere, reliable?*

**Summary of Positions**

In its initial testimony, BPA presented evidence relating to production costs for all aluminum smelters. Hoffard and Moorman, BPA, E-BPA-10, 35-36. Specifically, BPA presented cost curves originally developed by a consultant, Anthony Bird, showing 1985 variable costs and total costs for all smelters, with PNW smelters specially identified on the curves. *Id*. at Attachment 7. Based on this information, BPA concludes that PNW smelters exhibit a fairly wide spectrum of variable costs relative to the rest of the world's smelters, but that a large part of regional capacity is in the upper third of costs worldwide. *Id*. at 36. BPA corroborated this conclusion by examining cost information developed by other consultants and by constructing its own supply curves. Moorman and Hoffard, BPA, E-BPA-10, 37-38; Moorman, BPA, TR 3800, 3803, 3811-12, 3842-44.

The fact that a large part of the aluminum industry in the PNW faces variable costs in the upper third of costs worldwide creates a competitive situation that has serious implications for the operation of regional smelters. BPA notes that "there has continued to be development of new low-cost smelting projects that will be added to the lower end of the industry supply curve, forcing some existing plants to become 'swing' operations… Everything else being equal, the propects of more cyclical aluminum prices coupled with the addition of lower-cost capacity would suggest more frequent and larger fluctuations in operating levels of regional plants." Melton, BPA, E-BPA-36S, 3.

In testimony, the NWU specifically criticized BPA for confusing long-run and short-run phenomena. The NWU indicated that, although operating costs for new smelters may be lower than for existing plants, total production costs of new smelters may be higher than for existing plants and, therefore, these new
[page 9] plants will not displace existing regional plants. Wolverton, et al., NWU, E-NU-10, 22-23.

NWU argues that BPA's estimates of regional smelter costs are unreliable and should not be considered because they are based on consultants' reports that are proprietary in nature and available only by purchase from the consultant. Initial Brief, NWU, B-NU-01, 49-52. NWU contends that information obtained from other parties, which cannot be released, is subject to potential inaccuracies and/or bias. *Id*.; *see also*, Reply Brief, NWU, R-NU-01, 20-21. This position is echoed by OPUC/WUTC. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 9; Reply Brief, OPUC/WUTC, R-OP/WU-01, 8-11.

**Evaluation of Positions**

The evidence strongly indicates that a combination of increased costs of production in the region, volatile prices, and new smelters will result in swing operation of PNW smelters in the future. Some of the region's smelters are marginal relative to smelters worldwide. Melton, BPA, E-BPA-36S, 3; Hoffard and Moorman, BPA, E-BPA-51R, 18-19. The NWU criticism that BPA confuses short-run phenomena with long-run phenomena is unfounded. BPA's assumptions are derived from a short-run supply curve based on variable costs and the impact on those costs on the operation of PNW smelters. *Id*. at 19.

In developing its estimates of PNW smelter costs compared to the costs of smelters worldwide, BPA reviewed studies prepared by expert consultants, including Commodities Research Unit (CRU), Anthony Bird, Stuart Spector, Research Strategies Inc. (RSI), and Chase

Econometrics.  Because the studies were prepared by private consultants, they are available only by purchase.  They are proprietary in nature; BPA is contractually prohibited from releasing the studies to the public.  The NWU opposition to BPA's reliance on these studies is as follows: "[The BPA witness] did not determine smelter costs on a first hand basis.  TR 3856.  Instead, he used expensive consultants' reports.  TR 3851-54.  The reports are available only for payment of substantial sums and cannot be disclosed to other parties.  *Id*.  Therefore, Staff's testimony should not be given weight, as it is not subject to verification."  Initial Brief, NWU, B-NU-01, 49.

There is no dispute that BPA's aluminum price forecasts and the underlying justification for those forecasts are supported by studies that BPA cannot disclose due to their proprietary nature. There is also no dispute that these studies were prepared by expert consultants.  NWU acknowledges that these consultants may well be "the best and brightest" in the field.  *Id*. at 52. Thus, there is apparently no dispute as to the credentials of there experts.  In fact, NWU testimony concerning the production costs of the new Portland smelter in Australia is based in part upon undisclosed reports prepared by some of the same expert consultants that NWU now criticizes BPA for using.  Reply Brief, DSI, R-DS-01, 59-60.

The fact that these expert studies are available only by payment does not mean that BPA's conclusions based on such studies are unreliable or biased and
[page 10] must be disregarded.  The experts' studies are the most thorough, detailed, and well-documented studies available on aluminum price forecasting.  They are subscribed to by the aluminum companies themselves, relied upon by experts in the field, and have an international reputation for excellence.  As noted above, NWU does not contest the expert nature of these studies.  Virtually no other sources of information are available that are more reliable or of superior quality.  There are certainly no other comparable studies available that are not proprietary in nature.  Thus, the NWU and OPUC/WUTC arguments urge the Administrator either to ignore the best information available or to breach BPA's contracts with the consultants by disclosing the contents of the studies.

In any event, the expert testifying on BPA's behalf is the BPA witness, not the drafters of these studies.  The BPA witness is qualified as an expert in his own right and does not merely reiterate the contents of these studies, but rather develops his own opinion following a review of as much information as possible, including but not limited to these studies.  NWU does not accuse the BPA witness of "bad faith."  Initial Brief, NWU, B-NU-01, 52.  The weight accorded the BPA witness' expert opinion based upon expert studies should not be lessened simply because the studies are proprietary in nature.

During cross-examination of the BPA witness, NWU moved to strike those portions of testimony that were based upon proprietary information from these expert studies.  Moorman, BPA, TR 3854-55.  In denying the motion, the Hearing Officer ruled as follows:

> [The BPA witness] is not an employee of CRU or Bird or the other organization. There is no way that Bonneville or any government agency can operate if they have a function such as this to perform, other than bringing some ribbon clerk in and having him pull it out of the air.  That is just impossible.  I don't like this

> situation, but all I can rule is that an expert in this area - in this ratemaking area - or, in a number of other areas - is that if that's the information that is out there, and that's the only way it can be obtained - it's very clear that an expert can rely on his investigation, even on hearsay in certain circumstances. TR 3854-55.

The Hearing Officer's ruling is in complete accord with well established rules of evidence. In *United States v. Williams*, 447 F.2d 1285, 1290 (5th Cir. 1971) *cert denied* 405 U.S. 954 (1972), the Court stated that:

> the expert, because of his professional knowledge and ability, is competent to judge for him self the reliability of the records and statements on which he bases his expert opinion. Moreover, the opinion of expert witnesses must invariably rest, at least in part, upon sources that can never be proven in court. An expert's opinion is derived not only from records and data, but from education and from [page 11] a lifetime of experience. Thus, when the expert witness has consulted numerous sources, and uses that information, together with his own professional knowledge and experience, to arrive a this opinion, that opinion is regarded as evidence in its own right… (footnote deleted)

Similarly, it is for these reasons that Rule 703 of the Federal Rules of Evidence *expressly* permit an expert to rely upon facts or data that have not been admitted into evidence. *See also*, *United States v. Williams, supra*, 447 F.2d at 1291: it is "firmly established … that an expert's testimony need not be based solely upon records which are themselves introduced in evidence so long as the sources of information are of a type reasonably relied upon by experts in forming opinions or inferences upon the subject."

In any event, the expert studies are available to all parties who choose to purchase them. Moorman, BPA, TR 3807. BPA acknowledges the additional financial burden that purchasing these studies may have on some parties to this proceeding. However, no parties have offered any reasonable alternative to the use of such studies. BPA would be derelict in its duties if it did not purchase these expert studies and have them available for review by BPA's own experts prior to making fundamental economic decisions that directly effect the future of the aluminum industry in the PNW. Accordingly, BPA does not consider expert testimony that involves review of proprietary data either unreliable or biased.

**<u>Decision</u>**

*BPA's estimates of PNW smelter costs are reliable. Evidence obtained from expert consultants, though of a proprietary nature, was reasonably relied on in developing these cost estimates.*

**<u>Issue #3</u>**

*Should BPA assume all PNW smelters remain in operation?*

**<u>Summary of Positions</u>**

In its initial testimony, BPA included all of the region's aluminum smelters in the base forecast with all achieving full capacity utilization throughout the rate period. Hoffard and Moorman, BPA, E-BPA-10, 28. However, the low ranges, or pessimistic scenarios, included substantial reductions in forecasted operating levels. *Id*. at 29. Due to significant deterioration in aluminum price expectations, BPA introduced a revised medium forecast in supplemental testimony. Moorman and Hoffard, BPA, E-BPA-10S, In this forecast, no permanent closures were assumed although operations were assumed to fluctuate below full capacity during the rate period. *Id*. at 8. In addition, the low ranges in supplemental testimony assumed some smelter closures, based in large part on ASM results. *Id*. at 9-10.

[page 12]

NWU asserts that a company's decision to leave the aluminum industry does not mean that its smelter(s) would permanently close in particular, they contend that BPA incorrectly assumed that decisions by ARCO and Martin Marietta to leave the industry would result in permanent closure of two regional plants. Wolverton, et al., NWU, E-NU-10, 25.

**Evaluation of Positions and Decision**

BPA's initial and supplemental load forecasts assumed permanent smelter closures only in the low scenarios, which were prepared for purposes of reflecting uncertainty. However, recent events at Martin Marietta's smelter in The Dalles, Oregon suggest that this particular plant may be considered permanently closed. The Dalles smelter's production level has been reduced to zero. The plant has been for sale for approximately one year with apparently no acceptable offers. Industry analysts are not optimistic about restarting production at The Dalles plant. BPA has received a notice to terminate service at The Dalles plant. Moorman, BPA, STR 69. Moreover, Martin Marietta has indicated its intent to leave the aluminum and has already sold most of its remaining aluminum industry assets, including its other aluminum smelter in Goldendale, Washington. Therefore, BPA considers it appropriate to eliminate The Dalles plant from the medium forecast of regional loads in the final load forecast. *Id*. at 70. All other plants are retained in the medium forecast, although other plants also have been removed from the low scenarios.

**b. Nonaluminum DSIs**

**Issue #1**

*What load should BPA assume for Gilmore Steel?*

**Summary of Positions**

In its initial testimony of forecasted electric loads, BPA included a forecasted load for Gilmore Steel of 15 MW. Although BPA revised its expectation of loads for this plant for supplemental testimony, the load level modification inadvertently was not included in supplemental testimony.

ICP argues that including Gilmore Steel in BPA's load forecast is inappropriate since PGE signed a long-term power sales agreement with Gilmore in May 1984. Allcock, ICP, E-IC-13, 1-2.

## Evaluation of Positions and Decision

ICP is correct.  The Gilmore load is not included in the final load forecast.
[page 13]
## 2.  Generating Public Utility Loads

For the 1985 rate proposal, BPA forecasts generating public utility (GPU) loads with its own econometric forecasting model.  In the past, BPA used for planning the forecasts prepared by individual GPUs, as submitted by the utilities to the Pacific Northwest Utilities Conference Committee.  The GPU model is similar in structure to the models BPA uses to forecast non- and small-generating public utility loads.  This marks the first time BPA has used its own forecast of GPU loads in a rate filing.

### Issue #1

*Should BPA's generating public utility load forecasts rely on the load forecasts prepared by the generating utilities?*

### Summary of Positions

BPA's econometric model forecasts generating public utility (GPU) loads based upon projections of economic conditions, average retail electricity price, and weather.  BPA, E-BPA-06, 11.  BPA disaggregated the total GPU forecast to the individual utility level in order to complete reliable load/resource balances, perform residential exchange analyses, and compute low density discounts for this rate filing.  BPA, E-BPA-06A1, 248.  The disaggregation method used by BPA specifically incorporated forecast information from each individual GPU forecast. BPA, E-BPA-06, 10-11.

The PGP asserts that BPA should use the forecasts prepared by the individual generating utilities rather than BPA's own forecast, which includes GPU forecast data.  McGuire, PGP, E-PG-05, 1-17.  PGP maintains that while BPA's overall GPU forecast is reasonable, it is unreliable when disaggregated into individual utility components.  McGuire, PGP, E-PG-05, 1. PGP contends that each PGP member utility has a better understanding of the variables that affect their own loads, and thus the individual utility forecasts prepared by PGP members are more accurate than the disaggregated BPA forecast.  McGuire, PGP, E-PG-05, 7-9, Initial Brief, PGP, E-PG-01, 13-16.

### Evaluation of Positions

In support of its argument that BPA should adopt the load forecasts prepared by individual PGP utilities, the PGP placed considerable emphasis on the forecast prepared by one particular PGP utility, Grant County PUD.  The PGP compared Grant County's own load forecast with BPA's forecast of Grant County's loads, to demonstrate that BPA's forecast was less reliable and accurate.  Schneider, BPA, STR 96-98; Initial Brief, PGP, B-PG-01, 14.  PGP pointed out that Grant County's forecast of its own load was more accurate for July 1984.  However, the record demonstrates that BPA's forecast was more reliable for September, October, and November

1984. For those months, Grant County over projected load growth. McGuire, PGP, E-PG-05S, 1-4. BPA's forecast was more accurate than several other PGP member forecasts during that [page 14] period as well. McGuire, PGP, E-PG-05S, 4. Moreover, Grant County, in its most recent load forecast, has reduced its projection of load growth from its previous forecast. McGuire, PGP, STR 872. The PGP acknowledged that this new forecast has now moved closer to BPA's forecast. McGuire, PGP, E-PG-05S, 4. Several other utility forecasts have also been revised more closely to approximate BPA's forecast. McGuire, PGP, E-PG-05S, 4; BPA, E-BPA-06A1, 255-259; McGuire, PGP, E-PG-05, 10.

BPA is concerned about the reliability of individual utility forecasts: the record does not demonstrate that GPU forecasts have been reliable historically. For example, while Grant County PUD had been forecasting significant amounts of growth during the past several years, that growth has not been realized. Schneider, BPA, STR 94-95. With regard to other PGP member forecasts, the PGP acknowledged that it had not reviewed individual utility forecasts prepared by other PGP members to determine whether any particular utility had established a record of reliable forecasts. McGuire, PGP, STR 863. The PGP contends that BPA should have been able to determine whether each PGP utility had established a record of reliable forecasts based upon information provided to BPA through data requests. Reply Brief, PGP, R-PG-01, 11. Although the PGP answered BPA data requests, most responses were not sufficiently detailed for BPA to determine historical reliability.

In addition to claiming that BPA's GPU forecast is unreliable, the PGP claims that BPA's forecasts "operate unilaterally, without utilizing the reliable load data available from individual utilities" and that BPA is not using the "best data available". McGuire, PGP, E-PG-05, 1. This allegation, however, is not supportable. GPU load data available from the individual utilities are reviewed and analyzed by BPA and incorporated into BPA's GPU load forecast. The PGP forecasts are combined with actual historical load data. BPA, E-BPA-06, 10-11; BPA, E-BPA-06A1, 186, 248.

PGP is concerned that BPA use the most reliable information available in preparing its forecast of GPU loads. McGuire, PGP, E-PG-05, 1, 6-8. BPA has a similar concern with respect to the forecasts prepared by PGP members. Uniformity and consistent assumptions are important considerations in the development of a GPU load forecast. Hoffard and Moorman, BPA, E-BPA-10, 13. For instance, a major component in a load forecast is an estimate of future rate projections. Hoffard and Moorman, BPA, E-BPA-10, 13-14; BPA, E-BPA-06A1, 160-161, 237-238; Schneider, BPA, STR 76-78. In the case of the GPUs, a projection of future rates should incorporate a projection of BPA's wholesale rates, since PGP member utilities purchase firm loads from BPA. To the extent that the individual PGP utility forecasts assume a wholesale power rate projection different from BPA's, that load projection would most likely be erroneous. BPA, E-BPA-06A1, 294. PGP is unaware of the BPA wholesale power rate assumed in each PGP utility forecast. McGuire, PGP, STR 865-866, 869. Moreover, the PGP was unable to answer specific questions about each forecast. McGuire, PGP, STR 865-866, 869. It is very possible that the wholesale power rates embedded in PGP members' forecast are different from each other and from BPA's projections. Reply Brief, PGP, R-PG-01, 12.
[page 15]

**Decision**

*The PGP's contention that BPA load forecasts for each GPU are prepared unilaterally and without the benefit of individual GPU load data is erroneous. BPA recognizes that PGP members may have an advantage in understanding the variables that affect their loads. For this reason, BPA uses the PGP members' own forecasts in preparing BPA's forecast for each individual GPU.*

*The PGP has not demonstrated that BPA's forecasts are unreliable or in accurate. In fact, the record shows that the contrary is true. BPA's forecast is more reliable for the individual utility that the PGP selected for illustrative purposes. With respect to other PGP member forecasts, the record does not demonstrate that these forecasts have been historically reliable. Moreover, with the exception of Grant County PUD, the PGP has been unable to answer questions concerning assumptions and data contained in each PGP utility forecast. Accordingly, for purposes of this rate filing, BPA relies upon its own forecast of GPU loads, which takes into consideration each individual utility load forecast, rather than relying solely upon the load forecast prepared by each GPU.*

## C. Conservation

**Issue #1**

*Should BPA conservation program levels be reduced?*

**Summary of Positions**

BPA's proposed conservation program levels of $148.7 million and $165.0 million for FY 1986 and FY 1987, respectively, are derived as part of BPA's resource strategy and reflect cost sharing assumptions. Hickey, BPA, E-BPA-13, 4-8; E-BPA-13S, 1-7. PGE, PP&L, CPN, APAC, PNGC, and the DSIs argue that these program levels will not be met in FY 1987 and that BPA's revenue requirement should be reduced accordingly. They cite: (1) BPA's actual level of spending in past years; (2) the presence of utility cost sharing; and (3) the lower levels of utility participation as the major reasons for overstated spending projections. They argue that BPA should limit the revenue requirement associated with conservation to $100 million. McCullough and Young, PGE, PP&L, CPN, APAC, PNGC, and DSI, E-PD-01, 3-6. APAC reiterates this argument by suggesting that BPA could reduce 1987 program levels by $90-100 million and still remain above probable 1984 and 1985 levels. Initial Brief, APAC, B-PA-01, 22. The PNGC further suggests that BPA via cost sharing is "encourag[ing] and pay[ing] for more conservation on the generating utilities' systems." Reply Brief, PNGC, R-PN-01, 2.
[page 16]

**Evaluation of Positions and Decision**

The factors raised by the parties as reasons why BPA should reduce conservation program levels have all been considered in the development of BPA's program levels. First, as part of the resource planning process, BPA determines conservation savings targets to be acquired over the BPA loads of generating and non-generating utilities as part of a least cost mix of resources to meet a need for power in the deficit period. Hickey, BPA, E-BPA-13, 4-5. Second, BPA's analysis underlying 1986 and 1987 program levels includes a comparison with actual program implementation experience. Hickey, BPA, E-BPA-13, 6; E-BPA-06A1, 354. Third, BPA's program levels reflect a downward adjustment as a result of decreased expectation of additional utility participation. Hickey, BPA, E-BPA-13S, 3. Fourth, eligibility requirements and the guarantee premise under BPA's cost sharing principles limit conservation program levels by (1) keeping the cost of conservation on non-BPA loads out of BPA's budget; and (2) assuring reduction of only the BPA loads of generating or non-generating utilities. Hickey, BPA, TR 4085-4086; Hickey, BPA, STR 125. Program levels were further reduced by applying cost sharing percentages to the FY 1986 and FY 1987 budgets for the Residential Weatherization, Institutional Buildings, and Street and Area Lighting programs. Hickey, BPA, E-BPA-13S, 5-7.

The parties propose, without empirical basis, that BPA reduce its program levels to what they consider realistic or reasonable levels. McCullough and Young, PGE et al., E-PD-01, 6; Initial Brief, APAC, B-PA-01, 21. BPA's program levels for the initial proposal were reduced $14 million in FY 1986 and $19.1 million in FY 1987 to reflect the factors listed above. Hickey, BPA, E-BPA-13S, 1. These levels are reasonable projections for the years FY 1986 and FY 1987 in view of the downward adjustments already made and considering the underlying analysis used to develop the spending levels. They also result in a reduced revenue requirement for the test year.

The conservation program levels of $148.7 million in FY 1986 and $165.0 million in FY 1987 will not be further reduced.

**D. Revenue Uncertainty and Use of 1939 Water Conditions**

In its initial proposal BPA presented a Revenue Uncertainty Analysis (RUA) in response to concerns raised by the Commission and General Accounting Office (GAO) that sales and revenue underruns could have been reasonably anticipated and reflected in BPA's Repayment Study. 21 FERC ¶ 61,378 (1983). The RUA estimated revenues from five alternative load forecast scenarios and estimated a revenue forecast standard error of almost $200 million. The RUA predicted a much larger risk of underrecovery than of overrecovery, and concluded that there was an expected revenue shortfall of about $44 million from the base load forecast scenario used in the rate filing. To compensate for the expected revenue shortfall and to offset partially the potentially large
[page 17] underrecoveries, BPA proposed using nonfirm energy sales projections based on the 1939 water year for developing rates.

**Issue #1**

*Should the 1939 water year be used as a basis for cost allocation?*

**Summary of Positions**

In the initial proposal for the forecast of revenues, BPA used 1939 water conditions in order to reduce the risks of underrecovery. The Revenue Uncertainty Analysis was the basis for choosing this relatively low water year. Using 1939 water instead of using the average of 40 water years biased the allocation of transmission costs between Federal and non-Federal power. This effect was unintended. Wedlund, BPA, E-BPA-63R, 1.

The ICP argues that use of 1939 water artificially reduces intertie costs allocated to Federal users by 36 percent and increases costs allocated to non-Federal users by 37 percent. The ICP further maintains that the magnitude and shape of 1939 water year data are not representative of expected values. Wilson, ICP, E-IC-09S, 3-8.

PPC argues that the 1939 water year assumption understates the amount of nonfirm energy available to DSI first quartile service. O'Meara, PPC, E-PP-03, 14.

APAC and the Joint Parties argue that the use of 1939 water to allocate intertie and transmission costs between power and transmission customers results in an overallocation to transmission. Initial Brief, Joint Parties, B-JP-01, 13; Initial Brief, APAC, B-PA-01, 27. APAC also asserts that the shape and volume of water resulting from the 1939 water year has incidental impacts on peak and offpeak pricing and first quartile pricing. Cook, APAC, E-PA-08, 1-2. APAC claims that the use of 1939 water conditions to determine the allocation of costs to the DSI first quartile results in a mismatch of cost allocation and expected service. Initial Brief, APAC, B-PA-01, 27.

**Evaluation of Positions and Decision**

The use of 1939 water conditions could have the unintended side effect of misallocating transmission costs between Federal and non-Federal power. BPA intended to use 1939 water conditions only to reduce the risks of revenue underrecovery. Wedlund, BPA, E-BPA-63R, 1. The arguments of the parties that use of 1939 water skewed DSI first quartile allocations, misallocated costs between Federal and non-Federal power, and improperly affected seasonal pricing are correct.

The allocation problems can be solved by using the average of 40 water years to allocate transmission costs, to calculate service to the interruptible portion of the DSI customer load, and to project displacement of
[page 18] firm power purchases by generating public utilities. The average of 40 water year conditions is therefore used for cost allocation purposes.

**Issue #2**

*Is the Revenue Uncertainty Analysis an appropriate foundation for use of 1939 water conditions?*

**Summary of Positions**

BPA has chosen not to rely on a single estimate of firm loads, but instead analyze the revenue consequences of a series of load forecast scenarios. This is the Revenue Uncertainty Analysis, which was presented as support for BPA’s proposal to use 1939 water conditions rather than the average of 40 water years. This analysis demonstrates that: (1) BPA would face an expected revenue shortfall of $44 million if it continued to rely on its base case estimate of firm loads and average water conditions; (2) a revenue shortfall of over $400 million could occur; (3) the standard error of the revenue forecast is close to $200 million; and (4) there is a greater likelihood of underrecovery than overrecovery. Wedlund, BPA, E-BPA-63R, Attachment 1, 2-3. ICP and Joint Parties allege that use of 1939 water is contrary to sound ratemaking practices and that the evidence does not support a departure from use of average water conditions. Initial Brief, ICP, B-IC-01, 27-28; Reply Brief, ICP, R-IC-01, 3; Reply Brief, Joint Parties, R-JP-01, 17. ICP also alleges that the Commission order cited by BPA, 23 FERC ¶ 61,378 (1983), simply requires BPA to use a composite load forecast for ratemaking purposes and does not require BPA seriously to address revenue recovery problems. Reply Brief, ICP, R-IC-01, 4. ICP alleges that the RUA was not revised to reflect modifications by BPA in its base case load forecast, and thus has failed to show, using BPA's best estimate of expected sales, that there is any deficiency in expected revenues. Initial Brief, ICP, B-IC-01, 30. ICP alleges that the RUA is biased because instead of assuming a single high and single low forecast, BPA used a single high forecast and three low forecasts. *Id*. at 31. ICP alleges that BPA's assignment of probabilities to the load forecasts was incorrect and unsupported. Id. In its Reply Brief. ICP reiterates its criticisms and alleges that BPA should not have assumed revenues were distributed normally if the load forecasts BPA used were not distributed normally. Reply Brief, ICP, R-IC-01, 2.

**<u>Evaluation of Positions</u>**

ICP and Joint Parties allege that the use of 1939 water conditions is improper and the evidence does not support a departure from use of average water conditions. This argument simply ignores the evidence presented by BPA. The RUA results indicated an expected revenue shortfall of $44 million if BPA continued to rely solely on its best estimate of firm loads and average water conditions. Wedlund, BPA, E-BPA-63R, Attachment 1, 2. The evidence BPA submitted indicated an approximate $200 million standard error in the expected [page 19] revenue estimate and a potential revenue shortfall of over $400 million compared to a potential revenue surplus of $250 million. Wedlund, BPA, E-BPA-63R. Attachment 1, 2-3. It is clear that BPA had to take steps to help ensure recovery of its costs. The use of 1939 water conditions addresses the problems noted by the RUA that result from assumptions of average water and base case loads. The use of 1939 water helps reduce the potential underrecovery and increase the probability that projected payments to the Treasury will be made on a timely basis.

ICP alleges that since 1939 water is not used by other utilities, its use is inconsistent with standard utility practice. As discussed below, BPA was directed by the Commission to take steps to help ensure recovery of its costs. The argument that there is no precedent set by other utilities for use of 1939 water does not establish that BPA's actions are inappropriate. BPA is not required to wait for another utility to develop a solution to a problem BPA faces. The problems confronting BPA are not shared generally by other utilities. A large portion of BPA's costs are fixed. Wedlund, BPA, TR 3377. A large portion of BPA's load is temperature dependent space heating load. BPA's loads are also unique in light of the large (2600 MW) direct service industrial load. Hoffard and Moorman, BPA, E-BPA-10S, 8. The aluminum plants in the PNW face major uncertainties and this has implications for BPA's ratesetting process. Hoffard and Moorman, BPA, E-BPA-51R, 16. BPA also has a large hydro system, expected to generate 6894 MW of firm power from hydro projects out of 8332 MW total firm generation. BPA, FS-BPA-01A, Table E-2. These facts demonstrate that BPA's situation is unique. BPA's problem is not merely one of uncertain load forecasts. BPA cannot prudently ignore the evidence regarding BPA's difficulty in recovering its revenue requirement. BPA, furthermore, has been requested by the Commission to anticipate sales and revenue underruns in its development of rates. 23 FERC, 61,378 (1983). The Revenue Uncertainty Analysis performs this analysis; BPA uses 1939 water to compensate for these forecasted potential underruns consistent with sound business principles.

The ICP alleges that the Commission order cited by BPA requires BPA simply to develop a composite load forecast and does not require BPA to address BPA's revenue recovery problems. This is incorrect. The Commission order noted that there were a number of reasons why BPA failed to establish rates that recover BPA's costs. Load underruns were only one of these reasons. The Commission noted, however, that its authority over Federal rates was very limited, concluding that "[u]nder these circumstances, the absence of any adequate Commission remedial authority must logically place the burden on the Bonneville Administrator to remedy concerns identified by the Commission." In response to this direction from the Commission, BPA developed an approach to reducing its revenue recovery problem; namely, the use of 1939 water conditions.

The ICP next alleges that the probabilities assigned to the alternate load forecasts in the RUA were not modified to reflect modifications by BPA in its base case load forecasts; therefore, the RUA fails to show that there is any deficiency in expected revenues. Initial Brief, ICP, B-IC-01, 30; Reply Brief, ICP, R-IC-01, 3. This is incorrect. BPA was questioned about revising [page 20] the RUA and indicated that the RUA had indeed been rerun. Wedlund, BPA, TR 3457. BPA also noted that BPA expressly reviewed the forecasts developed for BPA's supplemental testimony. Id. BPA's expert witness concluded further that the results from the revised assumptions were not significantly different from the results in the attachment to E-BPA-63R. Id.

ICP asserts that it is inappropriate to use three low load forecasts and only one high forecast in the RUA. ICP cites no testimony or other evidence suggesting that use of such forecasts is improper. In any event, however, it is not inappropriate to use one high forecast and three low forecasts because the three low forecasts represent the greater downside risk of reduced purchases by aluminum plants due to lower aluminum prices. BPA, E-BPA-06A1, 24. The high forecast has the aluminum plants operating at capacity. Wedlund, BPA, TR 3444. Furthermore, BPA indicated that using three rather than one high load forecast would have resulted in a similar estimate of expected revenues as the estimate projected from one high load forecast since the DSI plants could not operate at levels higher than plant capacity. Wedlund, BPA, TR 3441.

The ICP next alleges that BPA's assignment of probabilities to the load forecasts was incorrect and unsupported. Again, the ICP does not rely on any testimony or evidence in the record in suggesting that the estimated probabilities are incorrect. The only testimony regarding the probabilities was presented by BPA. BPA testified to the reasonableness of the estimated probabilities. Wedlund, BPA, E-BPA-34; Hoffard and Moorman, BPA, E-BPA-10. The probabilities were based on the expert judgment of BPA's load forecasting staff. BPA's witnesses have extensive experience in forecasting BPA's loads, including the preparation of economic and demographic projections used as inputs in BPA's energy forecasting models.

Hoffard, BPA, Q-BPA-1; Moorman, BPA, Q-BPA-3. These same expert witnesses prepared BPA's load forecasts used in the 1985 rate proceeding. BPA's witnesses are thus extremely knowledgeable regarding load forecasts, and their expert opinions regarding probabilities of load forecasts are entitled to great weight. Their testimony regarding probabilities is not contradicted by any other witness in the rate proceeding. Indeed, no other party suggested alternative probabilities to be assigned to the load forecasts at issue. While BPA load forecasting witnesses were available for cross-examination on their proposed probabilities, they were not questioned on the reasonableness of the probabilities. Furthermore, it is not unreasonable to assign equal probabilities to forecasts of different levels. The ICP brief apparently assumes that the probabilities must be cumulative. The probabilities contained in the RUA are discrete and subject to the requirement that the probabilities add to unity. Wedlund, BPA, E-BPA-63R, Attachment 1, 2. Therefore, BPA assigned probabilities to different sets of potential events. Id. It was reasonable, in the judgment of BPA's experts, that two different series of aluminum prices could have the same probability of occurrence even if one price series was lower. BPA, E-BPA-06A1, 24.

The ICP next alleges that BPA should not have assumed revenues were distributed normally if the load forecasts BPA used were not distributed
[page 21] normally. Contrary to ICP claims, BPA did not assume that revenues were normally distributed. Wedlund, BPA, TR 3440, 3445-3446. The ICP claims are apparently based on the inclusion of Attachment 3 to Exhibit BPA-34. During cross-examination, BPA indicated that Attachment 3 could be utilized to demonstrate and was relied upon to conclude that the use of 1939 water conditions improved the likelihood that Treasury payments would be made on a timely basis. Wedlund, BPA, TR 3447. Whether revenues are normally distributed or not, the record is clear that there is a substantially greater risk of revenue underrecovery than overrecovery. The standard error of the revenue forecast is approximately $200 million.

**Decision**

*The RUA demonstrates that reliance on BPA's base case firm loads and average water conditions may result in a $44 million revenue shortfall. The RUA also demonstrates that a potential revenue shortfall of $400 million could occur and that the standard error of the forecast is $200 million. In light of these significant problems regarding revenue recovery, the RUA is an appropriate foundation for the 1939 water year assumption.*

**Issue #3**

*Will the use of 1939 water conditions result in an overrecovery of BPA revenues?*

**Summary of Positions**

Results of the Revenue Uncertainty Analysis indicate that BPA faces a potentially large revenue recovery problem, and that the risk of underrecovery is much greater than that of overcollection. While the use of 1939 water conditions does not guarantee that BPA will meet its repayment obligations to the U.S. Treasury, its use will increase the probability that those obligations will be met. Wedlund, BPA, E-BPA-63R, 2. The use of 1939 water conditions will not necessarily result in an overrecovery of revenues. Wedlund, BPA, E-BPA-63R, 2.

The Northwest Parties argue that by using 1939 water BPA credits at least $100 million less to firm rates than would be credited if BPA assumed average water. This is alleged to be a $100 million overestimate of BPA's revenue requirement. Initial Brief, Northwest Parties, B-NF-01, 26. The Joint Parties similarly argue that the use of 1939 water constitutes a $100 million contingency allowance. Initial Brief, Joint Parties, B-JP-01, 15. The Joint Parties argue that use of 1939 water conditions will, on average, collect revenues in excess of projected costs. Wolverton, McCullough, and Young, Joint Parties, E-JP-01, 19. The Joint Parties argue that even if BPA could adequately support the projected $44 million underrecovery identified in the Revenue Uncertainty Analysis, it would not justify the compensatory ratemaking measure. Reply Brief, Joint Parties, R-JP-01, 19.
[page 22]
APAC states that because BPA does not credit all projected average water non firm energy revenues against the firm cost allocation, BPA projects an overcollection of the total revenue requirement by $100 million. Therefore, use of 1939 water conditions, by mathematical necessity, creates a fund in excess of system costs and results in an unlawful overrecovery of the Administrator's system costs. Initial Brief, APAC, B-PA-01, 25-29.

WPAG argues that BPA's use of 1939 water to estimate nonfirm energy revenues is a conservative assumption and therefore prudent from a financial standpoint. This conservative assumption gives BPA a financial cushion that protects it from most of the risk of not meeting the repayment schedule. Having this cushion will give BPA more flexibility in dealing with unexpected events such as variable streamflows and load underruns. However, WPAG supports the use of 1939 water in conjunction with an Excess Revenue Adjustment Clause (ERAC), which would return money to BPA's customers when overcollecting revenues. Hutchison, Miller, Saleba, and Schneider, WPAG, E-WA-01, 18-1 9.

PGP argues that the use of 1939 water conditions causes an overrecovery of revenues and an overallocation of costs to BPA's firm power customers, and provides a contingency allowance that violates BPA's statutory mandates. PGP concludes that the use of 1939 water conditions is the wrong solution to the problem of load fluctuation. Initial Brief, PGP, B-PG-01, 11-13.

**Evaluation of Positions**

The evidence in the record demonstrates that BPA is likely to underrecover revenues if rates are based on average water conditions and base case loads. The RUA indicates: 1) that BPA could face an expected revenue shortfall of $44 million if it continued to rely on its base case estimate of firm loads and average water conditions; 2) that a potential revenue shortfall of over $400 million could occur; 3) that the standard error of the revenue forecast is close to $200 million, and 4) that the likelihood of underrecovery is greater than the likelihood of overrecovery. Wedlund, BPA, E-BPA-63R, Attachment 1, 2-3.

Numerous parties allege that the use of 1939 water overstates BPA's revenue requirement by $100 million. This is the alleged difference between rates developed assuming the 1939 water year and rates based on average water from a comparison prepared by BPA. This number, using the same methodology, is now substantially smaller. The difference between 1939 water and average water conditions is now $78.5 million in FY 1987 and only $39 million in FY 1986. This results in an average difference of only $60 million. This number varies from the original comparison because of differences in the nonfirm energy rate structure and because some offpeak nonfirm energy sales are assumed to be made at the NF-85 Standard rate. The parties thus allege that BPA is over recovering its revenue requirement by $60 million per year rather than $100 million.

The suggestion that BPA is recovering revenues in excess of costs is incorrect. First, the RUA has demonstrated that BPA has a likelihood of not [page 23] recovering its revenue requirement when assuming base case load forecasts and average water. Wedlund, BPA, E-BPA-34, 3. This is also supported by historical results. 23 FERC # 61,378 (1983). As noted by BPA, even assuming 1939 water, BPA has a 40 to 45 percent chance that it will not meet its repayment obligations. Wedlund, BPA, E-BPA-63R, 2. The use of 1939 water therefore does not guarantee that BPA will even obtain revenues that cover its costs. Some risk of underrecovery still remains; however, the likelihood of underrecovery is diminished. *Id*. The use of 1939 water conditions is a prudent response to the load and streamflow uncertainties that confront BPA.

As noted above, WPAG proposes an Excess Revenue Adjustment Clause in conjunction with use of 1939 water. Such a clause is unnecessary, however, because in the event that BPA were to overrecover revenues (an event which is hardly guaranteed), excess revenues would reduce BPA's future revenue requirement. This would mean that BPA would not need a rate increase as quickly as in the absence of excess revenues. Also, any future rate increase would be less than in the absence of the excess revenues. BPA's ratepayers therefore receive the benefits of any possible overcollection.

The Joint Parties suggest that the alleged $100 million difference between 1939 water and average water is not consistent with a projected $44 million underrecovery. Reply Brief, Joint Parties, R-JP-01, 19. Initially, as noted above, the difference between revenue projections using 1939 water and average water is not $100 million, but $60 million. BPA did not use 1939 water conditions solely to address a projected $44 million underrecovery, however. The use of 1939 water is an appropriate means of addressing BPA's revenue recovery problem for a number of reasons. BPA faces an expected revenue loss of $44 million, and, in addition, a larger potential underrecovery ($400 million) than overrecovery ($250 million), with a $200 million standard error in the RUA. Wedlund, BPA, E-BPA-63R, Attachment 1, 2-3.

Numerous parties allege that the use of 1939 water constitutes a contingency allowance. This is incorrect. Cross-examination of BPA's witness noted:

> Q. [By Mr. Garten: Is it correct that Bonneville is seeking to provide for itself, by using the 1939 water year, a contingency for any potential revenue underrecovery?
>
> A. [Mr. Wedlund: Absolutely not.

TR 3405. BPA noted that the 1939 water year was used as a method to help ensure that BPA would have a greater likelihood of recovering its revenue requirement in the face of problems such as load underruns and low streamflows. The Commission directed BPA to mitigate the effects of such contingent events. 23 FERC ¶61,378 (1983).

The fact that a ratemaking mechanism is related to contingent events, however, does not make it a contingency fund. For example, certain BPA [page 24] customers proposed a load adjustment clause, which directly involves a contingent event, but such a clause does not establish a contingency fund because it does not guarantee any excess revenues. Similarly, the use of 1939 water does not guarantee any excess revenues. It is simply a more conservative assumption to ensure BPA is more likely to meet its revenue requirement.

WPAG and APAC argue that use of 1939 water conditions will unnecessarily increase BPA's firm power rates and result in a reduction in firm power sales and revenues. Initial Brief, APAC, B-PA-01, 33; Reply Brief, WPAG, WA-R-01, 20. The parties cite no record support for these claims. It makes no sense to assume that BPA's PF-85 rate, which is virtually identical to BPA's preceding PF-83 rate, would result in a reduction in firm power sales and revenues. A PF rate increase of less than one percent is unlikely to have such effects.

**Decision**

*BPA uses 1939 water conditions to estimate expected excess revenues from nonfirm energy sales in developing rates. BPA is obliged to tale reasonable actions to meet its financial obligations in a timely manner. Failure to recognize the adverse financial impact of potential load underruns and/or low streamflow conditions would not be prudent. In no event is BPA attempting to use 1939 water conditions as a means to establish a contingency fund. The use of 1939 water provides a prudent level of revenue assurance to BPA consistent with sound business principles.*

**Issue #4**

*Is the use of 1939 water conditions lawful?*

**Summary of Positions**

BPA maintains that the use of 1939 water conditions is lawful.

WPAG asserts that, absent an adjustment clause to return any unused portion of a potential revenue overcollection to BPA's customers, the use of 1939 water would be unlawful for three reasons: (1) it would violate BPA's statutory obligation to set its rates at the lowest possible level consistent with sound business principles; (2) it would violate section 7(b)(1) of the Northwest Power Act by establishing rates for preference customers based upon costs incurred to serve the DSIs, rather than on the cost of FBS resources; and (3) it would violate a prohibition against BPA having contingency funds. Initial Brief, WPAG, B-WA-01, 17. The Joint Parties and APAC also allege that the use of 1939 water constitutes an unlawful contingency fund. Initial Brief, Joint Parties, B-JP-01, 14-19; Initial Brief, APAC, B-PA-01, 26-34. The Joint Parties, APAC and WPAG allege that the use of 1939 water conditions is inconsistent with section 7(g) of the Northwest Power Act. Initial Brief, Joint Parties, B-JP-01, 17; Initial Brief, APAC, B-PA-01, 32; Reply Brief, WPAG, R-WA-01, 19.

[page 25]

**Evaluation of Positions**

WPAG and the Joint Parties suggest that use of 1939 water is unlawful because it violates BPA's statutory obligation to establish the lowest possible rates consistent with sound business principles. This is incorrect. The WPAG brief implicitly admits that even with the 1939 water assumption, BPA's actual nonfirm energy revenues may not exceed projections. Initial Brief, WPAG, B-WA-01, 16. If nonfirm energy revenues were less than projected, BPA's rates could be argued to be too low, not too high. Furthermore, the RUA has established that even assuming 1939 water, there is a 40 to 45 percent chance that BPA will not meet its revenue requirement. Wedlund, BPA, E-BPA-63R, 2. BPA proposes to use 1939 water conditions partially to offset the substantial risk of underrecovery of its revenue requirement. Wedlund, BPA, E-BPA-63R, 2.

The statutory provision cited by the parties provides that BPA's rates should be the "lowest possible consistent with sound business principles." The parties, however, have virtually ignored the last phrase of the statutory standard. It is the essence of sound business principles that BPA meet its statutory obligations to recover its revenue requirement through its rates. Yet the record demonstrates that BPA has had historical difficulty in meeting its revenue requirement and that BPA has a greater than 50 percent likelihood of failing to meet its revenue requirement if it were to assume average water conditions and base case loads. No rational construction of the sound business principles standard can ignore the likelihood of revenue underrecovery, the large standard error of the forecast ($200 million), and the significantly higher probability of underrecovery than overrecovery. Thus, use of 1939 water is consistent with BPA's directive to establish the lowest possible rates consistent with sound business principles.

WPAG also suggests that the use of 1939 water would violate section 7(b)(1) of the Northwest Power Act. This argument was not raised during the proceeding; its meaning is unclear. WPAG may be suggesting that an assumption of 1939 water would reduce the size of the FBS, thus requiring more exchange resources to meet preference customer loads. This implication is incorrect: the size of the FBS is based upon critical period resources. The use of 1939 water would not affect the size of the FBS because 1939 water is in excess of critical water.

In its reply brief, WPAG again alleges that use of 1939 water without a rebate mechanism violates section 7(b)(1) of the Northwest Power Act. Reply Brief, WPAG, R-WA-01, 18. WPAG argues that the RUA demonstrates that the majority of projected revenue underrecovery is caused by DSI loads. Since the revenue instability associated with serving DSI loads is not an FBS or exchange cost, WPAG argues that DSI load costs are improperly included in the PF rate through use of 1939 water. There is no evidence cited by WPAG suggesting that the RUA demonstrates that the majority of projected revenue underrecovery is caused by DSI loads. Furthermore, the argument of WPAG is incorrect since the risk of a DSI load underrun is not only a DSI cost. The Joint Parties (which represent most customer groups) and WPAG overlook a

[page 26] significant point. If future DSI loads and water conditions could be forecasted accurately and BPA knew they would be lower than the base case projections, then all firm

power rates would be higher, unless the DSI rate were held at the floor rate determination. It is the underlying uncertainty that exists in the forecasts of loads and streamflow conditions as well as their resulting impact on revenues which suggests that a conservative assumption regarding nonfirm energy revenues would be an adequate remedy to the revenue recovery problems BPA faces. If BPA knew that the loads of one customer class would be lower than the base case projection, BPA would project less revenue from that class and increase the rates for other firm power purchases. Wedlund, BPA, TR 3486.

The Joint Parties, APAC, and WPAG suggest that the use of 1939 water constitutes an unlawful contingency fund. This is incorrect. The issue of whether the use of 1939 water constitutes a contingency fund has been addressed above. The issue of whether contingencies may be included in BPA's rates is discussed in part in Chapter III regarding investment service coverage and is not repeated here. The present discussion will address additional legal arguments related to BPA's authority to use the 1939 water assumption.

The Joint Parties and APAC allege that because BPA does not credit all projected average water nonfirm energy revenues against BPA's firm cost allocation, BPA overcollects its total system costs. Initial Brief, APAC, B-PA-01, 28-29; Initial Brief, Joint Parties, B-JP-01, 15. This argument is incorrect. The use of 1939 water does not ensure that BPA will recover more than its total system costs. Indeed, no party denies that even with the 1939 water assumption, BPA may actually undercollect revenues. This would result, in one example, from occurrence of a water year less favorable than 1939 water. In that instance, 1939 water would be an overly optimistic assumption and would not ensure that BPA would recover its total system costs. In addition, the record establishes that even assuming 1939 water, BPA has a 40 to 45 percent chance of failing to meet its revenue requirement. Wedlund, BPA, E-BPA-63R, 2. The 1939 water assumption does not guarantee any funds for contingencies or that BPA will collect more than its total system costs.

The Joint Parties and APAC next allege that the use of 1939 water would be improper because Congress viewed low water as a contingency which BPA could not consider in setting rates. Initial Brief, Joint Parties, B-JP-01, 15-16; Initial Brief, APAC, B-PA-01, 30-32. Ironically, the legislative history cited by the parties directly refutes their contention. As the House Interior Committee noted:

> [T]he Committee believes *it would be appropriate* for BPA to include as a cost in its rates an allowance to cover the possibility of less than average water conditions so as to enable it to make the timely repayments necessary to avoid the interest rate penalty (emphasis added).



H. Rep. No. 976, Part II, 96th Cong., 2d Sess. 54 (1980).

The parties suggest that the House Interior Committee "apparently failed to realize" that the House Commerce Committee was eliminating BPA's right to set rates allowing for contingencies. This assertion is wrong for a number of reasons.

First, as noted below, the bill upon which the House Interior Committee report is based does not contain a provision mandating the inclusion of contingencies in BPA's rates. This demonstrates that the Committee believed that inclusion of a cost in BPA's rates to allow for less than average water conditions was appropriate even in the absence of express language in the Northwest Power Act regarding contingencies.

Second, while use of 1939 water does not constitute a contingency fund, the failure of the House Commerce Committee to mandate an allowance for contingencies in BPA's rates did not make such contingencies unlawful, but rather, permissive. *See* Chapter III, Section D. This point is buttressed by the fact that existing legislation provides BPA with a statutory basis for including contingencies in rates. BPA has previously included contingencies in rates and received approval from the Federal Power Commission. 54 FPC 808, 811 (1975). The Northwest Power Act did nothing to affect this statutory foundation.

Third, the statement of the House Interior Committee is correct. Since BPA's statutory authority to include contingencies in rates, as noted by the FPC, lies in statutes enacted prior to the Northwest Power Act, the fact that BPA was not expressly mandated to account for contingencies in its rates under the Northwest Power Act does not affect the Committee's conclusion.

The Joint Parties and APAC also argue that section 8(d)(4) of the Northwest Power Act, precluding an interest penalty when a revenue shortfall is caused by low water, implies that BPA cannot estimate costs or revenues based on low water conditions. The parties argue that BPA would not need protection from such revenue shortfalls if BPA were entitled to allow for low water in setting rates. Initial Brief, Joint Parties, B-JP-01, 16-17. This argument is unconvincing. The version of the bill upon which the House Interior Committee based its report does not contain a provision to mandate BPA to include contingencies in its rates. *See* H. Rep. No. 976, Part II, 96th Cong., 2d Sess. 18 (1980). The Committee thus made its statement knowing that the proposal to mandate BPA to include contingencies in rates had been deleted, yet the Committee stated that it would be appropriate for BPA to include as a cost in its rates an allowance to cover the possibility of less than average water conditions. In addition, certain members of the Joint Parties advocate a water adjustment clause for BPA's rates. Initial Brief, PGP, B-PG-01, 26; Initial Brief, APAC, B-PA-01, 34. If a workable water adjustment clause were put in place it would provide an allowance for fluctuating streamflows. Since members of the Joint Parties advocate such an adjustment, they presumably view it as lawful. Yet under their own argument, the fact that they could propose a water adjustment clause would contradict [page 28] section 8 (d)(4) in the same manner as they suggest it contradicts BPA's position.

The Joint Parties and APAC allege that Congress had a general belief that BPA's rates were to be based on average or median water conditions. Initial Brief, Joint Parties. B-JP-01, 17. This argument is weak. The parties cite Appendix B of the Senate Report on S.885, S. Rep. 272, 96th Cong., 1st Sess., App. B, 66 (1979). This is the bill that would have expressly mandated BPA to include contingencies in its rates. A footnote from a table in Appendix B notes that the preference rate limit is "estimated on average kilowatt-hour cost based upon sale of all federal hydro and net-billed resource energy, including median year nonfirm energy." *Id.* The parties' reliance on Appendix B is misplaced. The quotation simply notes median water as one of many assumptions that were used in order to perform a preliminary study of BPA's possible wholesale power rates under the bill at that time.

The Joint Parties, APAC and WPAG allege that section 7(g) of the Northwest Power Act mandates the crediting of nonfirm energy revenues to firm power rates. Initial Brief, Joint Parties, B-JP-01, 17; Initial Brief, APAC, B-PA-01, 32; Reply Brief, WPAG, R-WA-1, 19. Section 7(g) fails to demonstrate that the use of 1939 water is inappropriate. Section 7(g) provides, in pertinent part:

> (g) Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including, but not limited to … the sale of or inability to sell excess electric power.

Section 7(g) simply addresses the allocation of certain costs and benefits under the Northwest Power Act. This provision provides the Administrator broad discretion in the allocation of costs. Section 7(g) provides that the Administrator "*equitably* allocate to power rates" (emphasis added) certain costs and benefits. The use of 1939 water is equitable in that it helps ensure that BPA will recover its costs by applying the 1939 water year projection to all firm power rates. Furthermore, nonfirm energy revenues continue to be credited to firm power rates under the 1939 water year assumption.

Section 7(g) is significant for additional reasons. Section 7(g) provides that BPA shall allocate to power rates the costs of "uncontrollable events." BPA has no control over whether projected loads will materialize or whether streamflows will be high or low. As noted above, Congress concluded than an allowance for low streamflows constitutes a BPA system cost. The RUA demonstrated that BPA was likely not to recover its revenue requirement due to these uncontrollable events. The RUA forecasted $44 million underrecovery,
[page 29] with a maximum underrecovery of $400 million. Thus, BPA properly allocated costs of uncontrollable events consistent with section 7(g) of the Northwest Power Act.

The Joint Parties and APAC argue that the use of 1939 water should be rejected because BPA failed to weigh the impacts of the proposal on BPA's customers and consumers. Initial Brief, Joint Parties, B-JP-01, 18; Initial Brief, APAC, B-PA-01, 32. This argument ignores the fact that no significant rate increases are proposed for any class of firm power customers. Furthermore, there are hundreds of issues in BPA's rate case, and BPA does not conduct separate price elasticity studies for every issue. The Joint Parties and APAC themselves made no suggestions and offered no analysis regarding any alleged impacts on BPA's customers. BPA did in fact provide, at the request of the parties, a comparison of BPA's forecasted revenues under average and 1939 water conditions. BPA also responded to voluminous data requests and provided the parties with all information requested.

The Joint Parties and APAC assume that BPA can specify the load impact of this particular assumption. This is not the case. BPA has provided forecasts of expected sales and alternative forecasts that might also occur. There is a substantial difference in the level of these forecasts.

One purpose of the Revenue Uncertainty Analysis was to quantify the financial impact of that uncertainty. The forecast uncertainty would still exist even if BPA fine-tuned its base forecast of expected loads to account for the myriad decisions that could affect that forecast. However, revisions to BPA's forecast of loads at this time would only delay the necessary revision in rates.

Finally, the cases cited by the Joint Parties are inapposite. Initial Brief, Joint Parties, B-JP-01, 18-19; Initial Brief, APAC, B-PA-01, 33. First, the citation to *Consumers Union v. Federal Power Commission*, 510 F2d 656, 659 (D.C. Cir. 1974), simply notes that the Commission "bears the burden of explaining the reasonableness of any departure from a longstanding practice," and facts underlying its explanation must be supported by substantial evidence. Similarly, citation to *Columbia Gas Transmission Corp. v. FERC*, 628 F2d 578, 591 (D.C. Cir. 1979), simply notes that in an unrelated case the Commission failed to base its decision on substantial evidence. This has little bearing on this case. In this case, BPA *has* based its decision on substantial evidence in the record and has thoroughly documented the reasonableness of its proposal. Furthermore, the alleged departure from past policy is a matter of degree. BPA must project water conditions for ratemaking purposes, whether based on a single water year or an average of 40 water years. BPA is simply using a more conservative projection in this case.

**Decision**

*The use of the 1939 water assumption is lawful. It is a conservative approach consistent with the evidence presented that will allow BPA more certainty in recovering its revenue requirement. This assumption complies*
[page 30] *with BPA's statutory requirement to set rates consistent with sound business principles.*

### E. Classification Issues

Classification apportions costs between those that are capacity-related and those that are energy-related. BPA classifies its costs in the Cost of Service Analysis (COSA) after the costs are functionalized to generation and transmission. Generation costs are classified by a uniform method that uses the percentages for capacity and energy determined using a combustion turbine in the Marginal Cost Analysis (MCA); transmission costs are classified all to capacity. The costs allocated to the Priority Firm Power rate are reclassified in the Wholesale Power Rate Design Study (WPRDS) according to the percentages for capacity and energy determined using load management in the MCA. The reclassification of costs allocated to Priority Firm Power is discussed in Chapter VIII, Section J.

The issues related to classification in the 1985 rate filing are discussed in two sections. First, generic issues concern the relationships of cost classification and the ability to recover revenues, the accuracy of demand and energy forecasts, and impacts on system load factor. The second section considers issues related specifically to the COSA's classification of costs.

#### 1. Generic Classification Issues

**Issue #1**

*What empirical evidence exists regarding the impact of classification on loads and revenues?*

**Subissue #1**

What conclusions may be drawn from Appendix C of the WPRDS?

**Summary of Positions**

BPA conducted an analysis of the load responses of two utilities that purchase power from BPA to supplement their own generation: Seattle City Light and Tacoma City Light. BPA, E-BPA-08, Appendix C, 350-361; Peters, BPA, E-BPA-35, 2-4 and Attachment 1, 1-10. This analysis used hourly loads on BPA; weekly data on retail loads served by the purchasing utility and on streamflows into the utilities' hydro electric projects; and BPA's PF rate schedule charges for the period October 1979 through September 1983. The study concluded that these two utilities use their own hydro potential to displace purchases of peak period energy, offpeak period energy, and single hourly peak demand from BPA. Further, the responses of these two utilities to
[page 31] BPA's diurnally-differentiated price of electricity were mixed, indicating no significant and consistent pattern of specifically different responses to demand and energy charges. BPA concludes that these results provide no basis on which to alter classification to achieve a particular, desired result in terms of revenue recovery.

APAC takes issue with a number of aspects of the research. (1) BPA's definition of the peak period energy price (AVPRICE) is not consistent with billing practices. Kalcic, APAC, E-PA-06, 4; Initial Brief, APAC, B-PA-01, 83-84. PGP agrees with APAC's criticism regarding the definition of AVPRICE. Opatrny and Spettel, PGP, E-PG-07, 9-10; Initial Brief, PGP, B-PG-01, 23; Reply Brief, PGP, R-PP-01, 16. (2) BPA's choice of weekly observations is inconsistent with monthly billing. Kalcic, APAC, E-PA-06, 5; Initial Brief, APAC, B-PA-01, 84. PGP concurs with APAC. Reply Brief, PGP, R-PG-01, 16. (3) AVPRICE is, but should not be, sensitive to the number of Sundays in the month. Kalcic, APAC, E-PA-06, 6; Initial Brief, APAC, B-PA-01, 84. PGP supports APAC's criticism. Reply Brief, PGP, R-PG-01, 16-17. (4) Some coefficients on the RELPRICE variable (ratio of peak period to offpeak period energy prices) have the wrong sign and/or are insignificant. Kalcic, APAC, E-PA-06, 7. (5) The analysis relies on only two utilities. Kalcic, APAC, E-PA-06, 10; Initial Brief, APAC, B-PA-01, 83. (6) Energy purchases are actually displaced more than capacity purchases. Kalcic, APAC, E-PA-06, 10 and Schedule 1 of Attachment PA-6-BK-1; Initial Brief, APAC, B-PA-01, 84. APAC claims that BPA "purports to rely on the infamous Seattle/Tacoma study" even though "the results and the purpose" of the study have not been validated. Reply Brief, APAC, R-PA-01, 29.

PGP argues that (7) RELPRICE should equal 1, since it is the ratio of peak energy price to offpeak energy price. Opatrny and Spettel, PGP, E-PG-07, 10; Reply Brief, PGP, R-PG-01, 17. (8) FLOW, which measures hydro-generation capability, should be designed to capture "factors that determine the ultimate use of … generation capability." Opatrny and Spettel, PGP, E-PG-07, 10. (9) The "assumption" that the coefficient on FLOW is negative will produce misleading results. Opatrny and Spettel, PGP, E-PG-06, 10. (10) The model ignores instantaneous adjustment to various factors by using a lag structure. Opatrny and Spettel, PGP, E-PG-07, 11. (11) The model ignores contractual constraints on behavior. Opatrny and Spettel, PGP, E-PG-07, 11-12; Initial Brief, PGP, B-PG-01, 24; Reply Brief, PGP, R-PG-01, 18. PGP also objects to the use of only two utilities. Initial Brief, PGP, B-PG-01, 22-23. PGP asserts that BPA rightly does not rely on the results of Appendix C. Reply Brief, PGP, R-PG-01, 15-16.

**Evaluation of Positions**

The 11 points raised by APAC and PGP will be addressed in turn.

(1) The technique used to define AVPRICE was used in other studies cited by BPA. Peters, BPA, E-BPA-35, Attachment 1, 3; BPA, E-BPA-08, 361. APAC reviewed these studies and did not question the definition of peak period energy used therein. Although some own-price elasticities in the Hirschberg
[page 32] and Aigner study were positive, Kalcic, APAC, TR 3974, APAC did not argue, nor is there any evidence, that this result was dependent on the definition of peak period energy price.

(2) Aggregation of weekly data into monthly observations would have eliminated much useful information regarding load responses. APAC concedes that quarterly billing for PSW customers does not necessarily imply that quarterly data should be used to analyze load responses. Kalcic, APAC, TR 3971-3972.

(3) The argument regarding the number of Sundays in a month demonstrates a fundamental misunderstanding regarding the role of AVPRICE, which is an expected peak period price. Peters, BPA, TR 3637-8. If only 1 hour in a month is potentially subject to the demand charge, then the load in that hour will certainly incur the demand charge. The expected price for load in that hour equals the demand charge plus the energy charge. If 2 hours in a month are subject to the demand charge, then there is some probability associated with each of the 2 hours that the demand charge will apply during that hour. The expected price in either of those two hours is then the energy charge, plus the demand charge times the probability of incurring that charge. As the number of hours during the month that are subject to the demand charge increases, so the expected demand charge for any one hour falls. As BPA’s demand charge is not assessed on Sundays, the number of Sundays in the month (all hours of which are not subject to the demand charge) will affect the expected price during peak period hours. This result is logical and follows from the definition of expected price.

(4) Coefficients that are insignificant do not invalidate the analysis, but only indicate that empirically the relative prices of peak and offpeak energy sometimes do not affect load. BPA, E-BPA-08, 358-360. One equation where the sign was "wrong" and the coefficient significant was for Seattle’s offpeak energy demand. This result may be explained by the likelihood that the output or quantity effect outweighed the substitution effect in this equation: BPA's prices increased so much during the 1979-83 period that even though offpeak energy was becoming inexpensive relative to peak energy, offpeak energy was becoming more expensive relative to all other goods to a greater extent, such that offpeak consumption actually fell.

(5) It is admittedly difficult to extrapolate from the load responses of two utilities. However, the analysis was restricted due to data limitations, not in an attempt to influence the results. BPA, E-BPA-08, 352. The conclusion of most importance in this regard is that factors specific to individual customers determine load responses to prices of energy and capacity. BPA, E-BPA-08, 350, 355-7; Peters, BPA, E-BPA-35, 3-4. Thus, one cannot conclude that a specific overall response to a particular classification can be confidently predicted for all of BPA's system. Existing evidence shows the contrary.

(6) The conclusion that energy purchases are displaced more than capacity purchases is erroneous. APAC's conclusions depend on results selectively and [page 33] uncritically extracted from BPA's own study. Some of the coefficients that were extracted were not statistically significant within their own equations. BPA, E-BPA-08, 358-360. Furthermore, cross-equation tests for significance must be performed before conclusions may be drawn about the significance of differences in estimated coefficients. APAC admits that it has not performed such tests. Kalcic, APAC, TR 3972.

(7) This argument concerning RELPRICE misunderstands the definition of the variable, which is not the ratio of posted energy-only prices in the peak and offpeak periods as PGP assumes, but the ratio of the expected energy prices in those periods. BPA, E-BPA-08, 351.

(8) This argument regarding FLOW misunderstands the nature of econometric analysis, which makes use of independent variables to explain the changes in a dependent variable. FLOW is an independent variable in BPA's study, determined exogenously by nature. BPA, E-BPA-08, 351. It is a measure of capability. To include in the specification of FLOW "factors that determine the ultimate use of … generation capability" could, if successful, introduce simultaneity bias into the analysis. PGP's claim that the use of dummy variables would prevent the introduction of such bias, Reply Brief, PGP, R-PG-01, 17, is unsubstantiated, because the "factors" and corresponding "dummy variables" have not been specified.

(9) There was no "assumption" regarding the sign of the coefficient on FLOW. There was a hypothesis regarding a particular result, that the coefficient on FLOW would be negative. Peters, BPA, E-BPA-35, 2. This hypothesis was supported by the data. Peters, BPA, E-BPA-35, 3.

(10) In this instance, PGP contradicts an earlier argument, in which they state that "[c]omputed requirements customers forecast the peak requirement that they intend to place on BPA each month. Having made that determination, the utility's expected monthly demand charge is known." Opatrny and Spettel, PGP, E-PG-07, 9-10. *Either* this forecast holds, *or* the utilities respond "continuously" and "instantaneously." Opatrny and Spettel PGP, E-PG-07, 11; Reply Brief, PGP, R-PP-01, 17. Both are not possible.

(11) it is admitted that contractual constraints may affect behavior. However, within contractual constraints responses to changes in prices and other exogenous variables can be postulated, and were analyzed successfully.

PGP asserts that BPA's Evaluation of the Record constitutes improper surrebuttal, and that BPA has presented "new 'evidence'" and "new points" by this means. Reply Brief, PGP, R-PG-

01, 16. However, no specific citations to "new evidence" are presented by PGP. BPA's evaluation of the points made by APAC and PGP with reference to Appendix C was careful to rely upon evidence already entered in the record and logical conclusions drawn from that evidence.

**Decision**

*Although BPA will continue to conduct research into the load responses of its customers, no serious flaws in the analysis reported so far have been*
[page 34] *pointed out and substantiated. The results show that the two utilities studied exhibit no significant and consistent difference in their responses to BPA's demand and energy charges. BPA relies on the results of the analysis in Appendix C only insofar as they provide no clear evidence that BPA should revise its current classification procedures to achieve specific revenue recovery goals.*

**Subissue #2**

What conclusions may be drawn from the demand and energy forecast accuracy study?

**Summary of Positions**

BPA submitted a study of the relative accuracy of its demand and energy forecasts. Peters, BPA, E-BPA-35, 4-8 and Attachment 2. BPA concludes that there is no significant difference in the accuracy of these forecasts for computed requirements, metered requirements, and DSIs for the PF-1/IP-1, PF-2/IP-2, and partial PF-83/IP-83 rate periods.

APAC raises two issues. (1) in the two complete rate period studied, energy revenues had a larger mean absolute percent error (MAPE) than did demand revenues. Kalcic, APAC, E-PA-06, 12. (2) BPA should not compare partial rate periods with full rate periods, but should compare partial periods with partial periods. Kalcic, APAC, E-PA-06, 12-13 and Attachment PA-6-BK-1, Schedule 2.

**Evaluation of Positions**

(1) The true test of a difference is not just whether a difference exists, but whether (a) the difference is statistically significant and (b) there is a pattern of significant differences in the nine comparisons of demand and energy forecasts, for PF and IP customers separately, in only three cases was there a statistically significant difference between demand and energy forecast accuracy: computed requirements customers during PF-2, metered requirements customers during PF-1, and industrial firm customers during the partial IP-83 period. Peters, BPA, E-BPA-35, Attachment 2, Tables 1 and 2. The fact that this happened only once for each customer group and then in three separate rate periods allows the conclusion that no pattern has been established. APAC's conclusion is erroneous.

(2) First, this position irresponsibly advocates throwing away data, without explaining why seven-twelfths of the available information should be discarded. Second, the subperiod of PF-1

chosen by Mr. Kalcic shows MAPE for demand significantly *greater* than the MAPE for energy, contrary to his conclusions. Third, the PF-2 subperiod chosen by Mr. Kalcic shows *no* significant difference between demand and energy, also contrary to his conclusions. Kalcic, APAC, E-PA-06, 16 versus 13. APAC's own calculations do not support its desired result.
[page 35]

**Decision**

*No serious flaws were uncovered regarding the forecast accuracy analysis, which showed no appreciable difference in accuracy of BPA's demand and energy load forecasts. BPA will continue however to examine this issue.*

**Issue #2**

*Does BPA's proposed rate design encourage the erosion of BPA's system load factor?*

**Summary of Positions**

The alleged "erosion" of BPA's system load factor is used as support for the suggestion that BPA should classify a larger percentage of its costs to capacity than it currently does. BPA states that cost classification has no clearly defined relationship to system load factor. Nor does BPA support the notion that increased operational efficiency is provided by a relatively high system load factor. Peters, BPA, E-BPA-52R, 10.

APAC claims that BPA's "progression toward energy-intensive rate design" results in "discourage[ment]" and "harm" to BPA's high load factor customers, which in some way lowers BPA's-system load factor. This situation is claimed to affect adversely the efficiency of operation of BPA's system. Pre-Hearing Brief, APAC, P-PA-01, 11-12; Initial Brief, APAC, B-PA-01, 79; Cook, APAC, E-PA-07, 1.

The ICP disagrees with APAC's assertion that BPA's cost classification and rate design have caused BPA's system load factor to deteriorate. Weitzel and Sirvaitis, ICP, E-IC-15R, 4.

**Evaluation of Positions**

APAC argues that the increasing energy-intensity of BPA's rates has caused an erosion or deterioration in BPA's system load factor. APAC states that a relatively lower load factor implies a less-efficient operation and the resulting "unnecessary" incurrence of cost. Cook, APAC, E-PA-07, 1.

APAC presents a table that purports to show the deterioration over time of BPA's system load factor. Cook, APAC, E-PA-07, 2-3. Using the data in that table, the conclusion cannot be reached that BPA's system load factor has systematically declined since the first use to classify costs of the MCA in 1979. The load factor in 1980, the first year for which the MCA-based rates would be in effect, is 57.4 percent; the 1983 load factor (the most recent on the table) is 61.3 percent. Cook, APAC, E-PA-07, 17 (Schedule 2). The BPA load factor is not "deteriorating," but is potentially increasing. Peters, BPA, E-BPA-52R, 10; Weitzel and Sirvaitis, ICP, E-IC-15R, 4.

The harm and discouragement that APAC claims are inflicted upon high load factor customers by BPA's supposedly increasingly energy-intensive rates are
[page 36] identified as "austerity and curtailments." That is, if the price of energy goes up, the high load factor customer's demand for that energy will go down. Cook, APAC, E-PA-07, 7. The resulting reoptimization of production that APAC claims will occur is simply a logical response to the change in the price of one of its production inputs. Peters, BPA, E-BPA-52R, 8. APAC does not provide support for its claim that an actual decline in system load factor will necessarily occur. Cook, APAC, E-PA-07, 7; Peters, BPA, E-BPA-52R, 8 and Attachment 2, page 2.

APAC also does not support its statement that "[a]s load factor declines, the Federal system runs less and less efficiently." Cook, APAC, E-PA-07, 8. APAC cites several studies to support its claim of the superior efficiency of high load factor system operation. None of the cited studies quantifies the benefit of a high system load factor, however, nor the resulting cost saving (if any). Cook, APAC, E-PA-07, 8-15. The memo from PNUCC that APAC cites as support for the assertion that a decline in BPA's system load factor could result in higher costs (Cook, APAC, E-PA-07-H-2) appears to be based on preliminary analysis and is unverified by APAC. Peters BPA, E-BPA-52R, 11. During cross examination BPA stated that the desirability of a particular load factor depends on the relationship of costs and revenues, and that a high load factor cannot be unequivocably assumed to be "better." Peters, BPA, TR 3690.

Finally, no relationship between the classification of costs and system load factor has been proven. Peters, BPA, E-BPA-52R, 10. Even APAC admits that system load factor may be affected by many variables: streamflow, ambient temperature, plant construction strikes, and seasonal load shapes. Cook, APAC, TR 3978-3979. To consider system load factor to be dependent only or even primarily on the classification of costs inherent in BPA's rate design is clearly incorrect. Peters, BPA, E-BPA-52R, 10.

**Decision**

*BPA's rate design, specifically the classification of costs between capacity and energy, has not been shown to cause any specific change in BPA's system load factor. In addition, the underlying premises remain unproven and unsupported. First, BPA's load factor is apparently not falling, and may even be rising. Second, the value of a high load factor on BPA's low capacity cost system has not been persuasively demonstrated. BPA's rate design takes into account the costs expected to be and actually incurred, and thus follows well-established procedures.*

**2. COSA Issues**

**a. Generation Costs**

Classification apportions costs between capacity and energy. The COSA classifies generation costs according to the percentages developed in the MCA.
[page 37]

**Issue**

*Should the COSA use a single method to classify generation costs?*

**Summary of Positions**

BPA classifies all generation costs according to the percentages for capacity and energy determined in the MCA. Emery, BPA, E-BPA-23, 2; Revitch, BPA, E-BPA-01, 5 and 20.

The DSIs seem to support BPA's uniform classification method. Carter, DSI, E-DS-07, 7; TR 3230. The DSIs assert, however, that hydro peaking units should not be classified according to the percentages developed in the MCA, but should be classified 100 percent to capacity. Carter, DSI, E-DS-07, 6-7; TR 3233; Initial Brief, DSI, B-DS-01, 128.

WPAG supports BPA's uniform classification of generation costs in the COSA based on the MCA. Hutchison, Muller, Saleba, and Schneider, WPAG, E-WA-01, 34; E-WA-02R, 23; Pre-Hearing Brief, WPAG, P-WA-01, 10-11; Initial Brief, WPAG, B-WA-01, 28; Reply Brief, WPAG, R-MA-01, 23. Specifically, WPAG disagrees with the DSI contention that hydro peakers should be classified completely to capacity. Hutchison et al., WPAG, E-WA-02R, 23-24.

OPUC supports BPA's classification of generation costs based on the MCA. White, OPUC, E-OP-01, 5.

NIU supports the concept of a uniform classification method. Gates, NIU, E-NI-03, 12; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 3; Initial Brief, NIU, B-NI-WS-NE-01, 5.

PGP supports BPA's uniform use of classification percentages. Knitter, PGP, E-PG-06, 1. PGP does not, however, support BPA's use of the MCA to classify costs. Initial Brief, PGP, B-PG-01, 16.

The ICP disagrees with the DSI proposal to classify hydro peaking plants using a method other than the uniform method. The ICP agrees with BPA's uniform classification method. Weitzel and Sirvaitis, ICP, E-IC-15R, 3.

SCE does not support BPA's use of a uniform classification method. SCE argues that the "relationship between capacity costs and energy costs varies by customer class." Waddell, SCE, E-CE-02A, III-1.

APAC disagrees entirely with BPA's use of a uniform classification method. APAC argues in favor of "determining classification on the basis of cost causation"; i.e., by means of resource-specific classification methods. Cook, APAC, E-PA-05, 2-3; Pre-Hearing Brief, APAC, P-PA-01, 10; Initial Brief, APAC, B-PA-01, 72-73; Reply Brief, APAC, R-PA-01, 29-30.
[page 38]

**Evaluation of Positions**

Most of the parties commenting on BPA's COSA classification procedures favor a uniform classification of generation costs. The DSIs support the uniform classification method as "much simpler and more straightforward than [BPA's] prior methods of classification." Nevertheless, the DSIs argue that BPA's MCA-based classification method should be used to classify the costs of only the resources that produce the joint products of capacity and energy. The DSIs maintain that the hydro peaking plants are resources that do not produce joint products; the hydro peakers provide only capacity and their costs should be classified 100 percent to capacity. Carter, DSI, E-DS-07, 6-7; TR 3233-3234; Initial Brief, DSI, B-DS-01, 128. An analogy with hydro peakers may be drawn for the Hanford plant. BPA considers that the Hanford plant produces no joint products, but produces only energy; for this reason, the costs of the Hanford plant have in previous rate filings been classified all to energy. 1983 Rates ROD, 63-64. The rationale for the classification of Hanford costs 100 percent to energy holds also for the classification of hydro peaker costs 100 percent to capacity. Carter, DSI, TR 3235. These resource-specific methods of classification are based on the principle of cost causation. BPA, E-BPA-01, 5; Emery, BPA, E-BPA-23, 3-4.

BPA is not implying that these resource-specific classification methods are incorrect. These methods, as well as the uniform classification method, are consistent with the principle of cost causation. Emery, BPA, E-BPA-23, 6. The manner in which the MCA calculates the marginal cost of generation, and its components of capacity and energy costs, considers the operation of both the existing generation resources (as does the principle of cost causation) and the resources that are projected to be added to satisfy future system power needs. Emery, BPA, E-BPA-22, 5; E-BPA-02, 5-6; TR 2937-2938. The goal of uniform classification is the same as the goal of resource-specific classifications: rates that encourage economic efficiency. Emery, BPA, E-BPA-23, 6. Implementation of the DSI proposal, therefore, would not enhance the theoretical basis for classification. Indeed, the DSI proposal would lessen the practical advantages uniform classification has over resource-specific classifications. Hutchison, et al., WPAG, E-WA-02R, 24; Initial Brief, WPAG, B-WA-01, 28. The advantages of uniform classification include simplicity; ease of application and understanding; consistency of results with BPA’s past methods; and the provision of consistent price signals that promote economic efficiency. Emery, BPA, E-BPA-23, 6. Implementation of the DSI proposal for hydro peaking plants (and, by analogy, also for the Hanford plant) would only detract from the advantages of the uniform classification method. WPAG points out that any uniform procedure will likely give rise to instances where the procedure can be argued not to apply. Hutchison, et al., WPAG, E-WA-02R, 23-24.

SCE's argument that the economically efficient relationship of capacity costs and energy costs varies by customer class is based on short run considerations and ignores the systemwide nature of BPA's costs. SCE is concerned with BPA's price of nonfirm energy, to which SCE attributes only the "short-run incremental cost of the energy." SCE continues, "[u]niform [page 39] classification applies the systemwide average of capacity to energy cost." SCE argues that this systemwide method is inappropriate for BPA's ratesetting. Waddell, SCE, E-CE-02A, III-1. SCE is correct in its characterization of BPA's uniform classification method as a system-wide approach. Weitzel and Sirvaitis, ICP, E-IC-15R, 3. BPA, as a marketer of power, evaluates the relationships of the components of its costs on a system-wide basis in order to promote the efficiency of operation of its system. Emery, BPA, E-BPA-23, 6.

APAC believes that the use of marginal costs has no place in ratemaking. Cook, APAC, E-PA-05, 1; Initial Brief, APAC, B-PA-01, 72. Therefore, because BPA's uniform classification method is based on the MCA, APAC claims that the "uniform classification procedure has no basis whatsoever." Cook, APAC, E-PA-05, 3. APAC supports cost causation as a basis for classifying costs between capacity and energy, and recommends that cost causation and "operating realities" of the generation system be recognized by using a myriad of classification methods. Cook, APAC, E-PA-05, 3. However, BPA's uniform classification method is consistent with the principle of cost causation, in that the MCA classification percentages are developed considering the operation of BPA's existing and projected resources. Emery, BPA, E-BPA-23, 5. The use of the percentages for capacity and energy determined by the MCA thus allows the classification procedure to consider not only operating realities, but economic efficiency. The relationship of capacity costs and energy costs is reflected in price signals that allow BPA's customers to make rational consumption decisions. Emery, BPA, E-BPA-23, 6; Reply Brief, WPAG, R-WA-01, 23. A number of the parties approve of the uniform classification method because of its understandability, consistency, and ease of application. Hutchison, Muller, Saleba, and Schneider, WPAG, E-WA-01, 34; E-WA-02R, 23; White, OPUC, E-OP-01, 5-6; Knitter, PGP, E-PG-06, 1; Carter, DSI, E-DS-07, 7.

**<u>Decision</u>**

*The use in the COSA of a uniform classification method for generation costs is reasonable. The use of the classification percentages calculated in the MCA promotes rate continuity and encourages economic efficiency. A uniform method promotes understanding, ease of application, and consistency. Using a uniform classification results in an overall classification of costs nearly identical to that achieved using BPA's previous methods. Emery, BPA, E-BPA-23, 6. BPA performed several analyses for the 1985 rate filing to examine the effects of its overall classification results. See Generic Classification Issues, supra. No untoward effects have been shown by BPA’s analyses; the record supports BPA's classification methods.*

### b. Classification of Transmission Costs

The MCA classifies portions of the incremental costs of the network and generation-integration transmission segments to energy to reflect the cost causation of the projected investment expenditures for those two segments. The COSA classifies all transmission costs to capacity.



**<u>Issue</u>**

*Does the COSA classify transmission costs appropriately?*

**<u>Summary of Positions</u>**

BPA classifies transmission costs 100 percent to capacity in the COSA. BPA, E-BPA-01, 3 and 21; Emery, BPA, E-BPA-23, 7.

WPAG urges that a portion of COSA transmission costs be classified to energy, based on the analysis in the MCA. Pre-Hearing Brief, WPAG, P-WA-01, 18; Hutchison, Muller, Saleba, and Schneidcr, WPAG, E-WA-01, 48-49; Initial Brief, WPAG, B-WA-01, 29.

OPUC favors classifying costs using the MCA, and disagrees with BPA's classification of COSA transmission costs all to capacity. Pre-Hearing Brief, OPUC, P-OP-01, 2; White, OPUC, E-OP-01, 18.

SCE appears to support BPA's COSA classification of transmission costs all to capacity by criticizing the MCA's classification of a portion of incremental transmission costs to energy. Waddell, SCE, E-CE-02A, II-11 and 12.

NIU supports BPA's classification of transmission costs. Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 11.

APAC apparently also supports BPA's classification of COSA transmission costs all to capacity. Cook, APAC, E-PA-05, 8 (Schedule 1).

**Evaluation of Positions**

Standard utility practice has traditionally classified transmission costs 100 percent to capacity. BPA, E-BPA-01, 5. BPA's classification of costs in the COSA conforms with the industry practice and promotes rate stability and continuity. Emery, BPA, E-BPA-23, 7.

WPAG advocates that a portion of transmission costs should be classified to energy in the interest of "cost-causation, economic efficiency, and equity." In addition, the use of the MCA classification for transmission costs would "enhance the consistency and continuity of BPA's classification procedures." WPAG did not specify the manner in which the MCA results for transmission costs should be applied in the COSA for classification. Hutchison, Muller, Saleba, and Schneider, WPAG, E-WA-01, 48. The OPUC criticizes BPA for "ignoring" the results of the MCA when classifying transmission costs in the COSA. The OPUC also did not specify a method for applying the MCA results to the COSA transmission costs. White, OPUC, E-OP-01, 6-7.

BPA acknowledges that application of the marginal cost-based classification percentages for incremental transmission costs to the COSA
[page 41] transmission costs would be theoretically correct. Emery, BPA, E-BPA-62R, 10. In a practical sense, however, the MCA transmission cost classification analysis is not useful. The MCA analyzes the relationship of capacity and energy costs for only two segments of the transmission system. Emery, BPA, E-BPA-23, 7-8. This is because only the network and generation-integration segments are needed to deliver an increment of generation to an increment of load for all customer classes. Emery, BPA, E-BPA-02, 16. It is not self-evident that a theoretically correct method exists to extend the classification results for those two segments uniformly to all nine transmission segments. In addition, application of the MCA transmission classification percentages to the COSA costs would not encourage rate stability. Emery, BPA, E-BPA-62R, 10. The reasons for this are (1) transmission investments are made in relatively large increments; and (2) the MCA uses a relatively short planning horizon for transmission

investments (8 years) inasmuch as detailed investment data for later years are not available. Emery, BPA, E-BPA-02, 15-16. Both of those factors make the MCA transmission classification percentages "variable and … sensitive to the amount of transmission investment" in each segment during the study period. In order to promote rate stability, the MCA for the classification of transmission costs must be performed for a period longer than that in the current MCA. A longer term approach is not possible at this time, however, due to the lack of necessary information. Emery, BPA, E-BPA-62R, 10.

**Decision**

*BPA classifies the COSA transmission costs appropriately. Classifying transmission costs 100 percent to capacity promotes rate continuity and stability, and conforms with industry practice. Future refinements to the MCA data and methods may increase the practicality of its use for classifying COSA transmission costs in future rate filings.*

[page 43]

## III. REVENUE REQUIREMENT

### A. Introduction

BPA is a self-financing power marketing agency within the United States Department of Energy. Rates for the sale of electric power and transmission services are BPA's only sources of revenue. See *Central Lincoln PUD v. Johnson*, 735 F.2d 1101, 1116 (9th Cir. 1984). These rates must produce revenues sufficient to repay all Federal investments in the Federal Columbia River Power System (FCRPS). 16 U.S.C. §§832f, 8389 and 839e(a). At the same time, BPA must set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. 16 U.S.C. § 839e(a)(1). The Revenue Requirement Study determines the level of revenue required to coverall of BPA's expenses and obligations over the cost evaluation period, consistent with all of these statutory obligations. As ordered by the Federal Energy Regulatory Commission (Commission), separate revenue requirement determinations are made for the transmission and generation portions of the FCRPS. *U.S. Department of Energy, Bonneville Power Administration*, 26 FERC ¶61,096 (1984).

Six general issues related to revenue requirement were raised during the 1985 rate proceedings: sources of data, revenue requirement calculation, adjustments, BPA's "separate accounting" compliance report filed with the Commission on May 29, 1984, residential exchange subsidy projections, and fish and wildlife program levels.

### B. Revenue Requirement Study Data

**Issue #1**

*Has BPA correctly projected the interest rate at which it will borrow funds from the United States Treasury during the repayment period?*

**Summary of Positions**

BPA's borrowing rate from the Treasury is estimated by determining the ratio of BPA's borrowing interest rate for FY 1983 relative to the interest rate on 20-year U.S. Treasury bonds for the same year. This ratio is then applied to the Data Resources, Inc. (DRI) estimate of interest rates on U.S. Treasury 20-year bonds to project BPA's borrowing rate for each year of the repayment period. BPA, E-BPA-07A, Chapter 14, A-3, A-4. BPA used this methodology in each of the past two general rate proceedings. PGP maintains there is inadequate justification for the methodology. Winterfeld, PGP, E-PG-03, 15-17; Reply Brief, PGP, R-PG-01, 2. Also, PGP states that this
[page 44] interest rate calculation should not apply to Corps and Bureau replacements. Reply Brief, PGP, R-PG-01, 3.

While PGP agrees that the DRI forecast of the 20-year U.S. Treasury rate is a reasonable basis for the calculation of BPA's borrowing rate, PGP states that BPA has not provided a sufficient basis for anticipating that the Treasury will charge BPA a premium over-and-above 20-year government bond rates on FY 1986 and FY 1987 borrowings. Winterfeld, PGP, E-PG-03, 15-16.

**Evaluation of Positions**

BPA's only source of borrowed capital is the U.S. Treasury, which unilaterally establishes the BPA borrowing rate. BPA has paid a premium over and above Treasury borrowings on all previous borrowings, consistent with Treasury Department policy. BPA, E-BPA-07A, Chapter 14, 8-3, D-3. BPA's approach assumes that there is a constant relationship between the cost of money to the Treasury and the interest rate that the Treasury charges BPA for its borrowings. BPA, E-BPA-07A, Chapter 14, A-3 to B-1.

PGP implies that a premium has not been paid on all previous borrowings. The PGP claims that the premium covers only FY 1983 borrowings. Reply Brief, PGP, R-PG-01, 3. PGP is incorrect. As noted by PGP, all of BPA's previous borrowings were made as authorized under the Federal Columbia River Transmission System Act and the Northwest Power Act. These laws require that a premium be charged to BPA for borrowing from the BPA fund. 16 U.S.C. §838k(a). The historical data on page D-3, Chapter 14 of Documentation for Revenue Requirement Study also demonstrate the effect of this premium on BPA's borrowing rate for FYs 1978-1982. BPA, E-BPA-07A, Chapter 14, Page D-3. BPA's inclusion of a premium above the Treasury rate is therefore appropriate.

Second, PGP suggests that a weighted average of BPA's actual and estimated borrowings in the latter half of 1983 (85 percent of which were made in the month of September) should not be compared with DRI's estimated 20-year Treasury rate for the entire year of 1983. Instead, PGP argues that the comparison should be based on the interest rate prevailing at the time of BPA's borrowing. Winterfeld, PGP, E-PG-03, 16-17. PGP's approach would provide for a more accurate estimation of BPA's borrowing rate.

Third, PGP argues that replacements associated with Corps and Bureau projects should be assigned interest rates estimated, under their interpretation of Department of Energy (DOE)

Order RA 6120.2, with no premium above the Treasury rate. Reply Brief, PGP, R-PG-01, 3-4. This is a new issue raised by PGP for the first time. This issue has never been raised in any BPA rate case. No party or BPA has had an opportunity to address it. BPA therefore does not adopt the PGP position in the final proposal. Even if the PGP adjustment were to be made, however, the effect would be less than $200,000. This is true given: (1) the size of the premium; and (2) the fact that the calculation would be based on the previous year's Treasury rate coupled with the consideration that the DRI data used show a pattern of declining interest rates. BPA, E-BPA-07A, Chapter 14, A-3.



**Decision**

*PGP's criticism of BPA's borrowing rate estimate is unconvincing. A clear relationship is evident between BPA's cost of money and the Treasury interest rate. A premium has been paid on all BPA's Treasury borrowings.*

*PGP's second criticism, however, has merit. As suggested by the PGP, the calculation of BPA's borrowing rate is based on a comparison of the Treasury interest rates prevailing at the time of the borrowing. This change refines BPA's repayment methodology to more accurately reflect BPA's cost of borrowing.*

*PGP's third proposal, that generation replacements be assigned the DOE Order RA 6120.2 interest rate, was improperly raised for the first time in PGP's reply brief and will not be incorporated in the final proposal. Even if adopted, the adjustment would be insignificant.*

**Issue #2**

*Are projected operation and maintenance (O&M) expenses correctly stated?*

**Summary of Positions**

BPA's budget is the basis for most of the cost estimates used in the Revenue Requirement Study. The Revenue Requirement Study incorporates program estimates made for the cost evaluation period in BPA's midyear budget review update of June 4, 1984, and adjustments made to reflect new construction assumptions about WNP-1 and -3. Roberts, BPA, E-BPA-21S, 2-4.

The Joint Parties have two comments regarding BPA's estimates of O&M expenses used in the Revenue Requirement Study. First, they assert that BPA's escalation rate for determining FY 1986 and FY 1987 O&M expenses is in accurate because BPA's forecast of the FY 1984 escalation rate was in accurate. Second, BPA's actual O&M expenses for FY 1984 were $65.6 million lower than the amounts projected in the 1983 rate case. As a result, the Joint Parties recommend that BPA revise its estimates of the FY 1986 and FY 1987 O&M expenses downward to reflect the historical results for FY 1984. Initial Brief, Joint Parties, B-JP-01, 21-24.

The Joint Parties propose application of a 5 percent annual inflation rate to actual BPA O&M expenses for FY 1984. Using this rate, they derive an estimate that is $56 million lower than the FY 1987 estimates in BPA's supplemental testimony. The Joint Parties argue that this approach

to estimating O&M expenses would be more accurate than the program-by-program approach used in the BPA budget. Wolverton, McCullough and Young, Joint Parties, E-JP-01S, 5; Reply Brief, Joint Parties, R-JP-01, 20. The Joint Parties suggest that the record does not justify proposed O&M expenses on a program-by-program basis. Finally, the Joint Parties claim that BPA's
[page 46] forecast of O&M expenses is not documented in the record. Reply Brief, Joint Parties, R-JP-01, 20-22.

**Evaluation of Positions**

The Joint Parties claim that BPA's escalation rate is in accurate. Initial Brief, Joint Parties, B-3P-01, 22. They state that BPA projected its O&M figure for FY 1985 using an escalation factor applied to FY 1983 figures. Initial Brief, Joint Parties, B-JP-01, 21. This is incorrect. In actuality, BPA developed new program level estimates for FY 1985, FY 1986 and FY 1987, each expressed in end-of-FY 1983 dollars. Escalation factors were used merely to convert end-of-FY 1983 dollars to current dollars in FY 1985, FY 1986 and FY 1987. These escalation factors were developed as shown in BPA, E-BPA-07A, Chapter 13. The effect of any inaccuracy in the escalation rates is therefore minimal.

Second, the Joint Parties assert that BPA's FY 1984 O&M expenses were less than originally forecasted. Initial Brief, Joint Parties, B-JP-01, 23. They imply that this underrun suggests a trend for O&M expenses during the rate period. The Joint Parties' proposal, however, provides no basis or evidence for extending this "trend" through FY 1987, nor does the proposal include any consideration of the cost of the individual programs in the cost evaluation period.

The Joint Parties' proposal that an overall inflation rate be applied to BPA's 1984 O&M levels contains a number of unreasonable assumptions. The proposal assumes that the costs of all programs increase at the same rate. In addition, the proposal assumes no program cost increases over-and-above the general rate of inflation. Wolverton, Joint Parties, STR 435. This "gross amount" approach to estimating O&M expenses cannot be adopted by BPA, which is a constrained by Department of Energy (DOE) regulations to analyze each specific component of O&M. DOE Order RA 6120.2 specifically requires that forecasts of O&M expense "shall take into account known factors which are expected to affect the future level of such costs during the cost evaluation period." BPA, E-BPA-07A, Chapter 14, E-10. The best estimates of future levels are contained in BPA's budget as incorporated into the record. BPA, E-BPA-07, 51-56. It is also necessary to examine individual programs in order to identify transmission and generation costs for separate repayment studies and because customer classes are allocated different shares of the costs of each program. In addition, the Joint Parties do not demonstrate that the underrun of O&M expense's in FY 1984 is a recurring phenomenon.

The Joint Parties' proposal that FY 1984 actual expenses be used as the sole base from which to project costs for the cost evaluation period is unreasonable; it assumes that O&M costs will exhibit the same characteristics every year after taking inflation into account. The fact that BPA underran O&M expenses in one year does not mean that it will underrun expenses in a subsequent year, nor should this single occurrence be used as a basis for forecasting O&M

expense. In contrast, BPA's "program by program" approach properly examines the characteristics of each category of expense. Finally,
[page 47] the Joint Parties provide no support for the 5 percent adjustment except that it reflects a "rough estimate" of what the forecasting services are projecting. Wolverton, Joint Parties, STR 435. This is in sufficient basis.

The Joint Parties assert that BPA's O&M expenses are not justified on a program-by-program basis. The Joint Parties ignore the budget data shown on pages 51 through 56 and described on pages 22 through 35 of the Revenue Requirement Study. BPA, E-BPA-07, and BPA, E-BPA-07A. Although BPA's budget is not in the record, it is a public record document to which the Joint Parties (ICP and PGP) cite repeatedly in their briefs.

BPA's budget has never been subject to change in the rate proceedings. The budget is BPA's plan for financial operation. BPA develops its budget estimates on a program-by-program basis. Offices with lead program responsibility prepare the program proposals with the assistance of the Division of Planning and Budget. Each program is reviewed by management to assure compliance with BPA's statutory objectives and to ensure that the proposals are fiscally prudent. BPA's budget is then reviewed by the Department of Energy, the Office of Management and Budget, and Congress. Congress conveys to Bonneville, through reports from appropriate committees, its concerns or views on the BPA budget. The rate proceeding is not, therefore, an appropriate forum for determining budget levels.

The Joint Parties claim that BPA's forecast of O&M expenses is not documented in the record. BPA demonstrates above that its forecast is documented and that no reasonable alternative was proposed by parties to the rate proceeding. While BPA is not relying on the following data in reaching its decision, it should be noted that BPA supplied the rationale for expenses underrunning forecasts in FY 1984 in response to ICP data request number 251C. Actual O&M expenses were $66 million less than projected in the 1983 rate proposal. The BPA response documented several reasons for this. First, inflation was overestimated for FY 1984. Second, certain components of the conservation and construction programs as well as certain indirect costs were capitalized rather than expensed. Third, projects under a number of fish and wildlife contracts were not sufficiently far along to be invoiced and therefore were not considered a FY 1984 expense. Fourth, research, development and demonstration activities for generating projects were scaled back. Finally, BPA's wheeling expenses underran projections. The Joint Parties were thus aware of the reasons that BPA's actual expensess [sic] underran forecasts.

**Decision**

*As noted by the Joint Parties, BPA's O&M expenses underran 1983 rate case projections by $65.6 million in FY 1984. In recognition of this fact, the Joint Parties' proposal would reduce BPA O&M by $56 million in the test year. However, the Joint Parties' proposal assumes that all BPA's program costs increase at the same rate and that no program cost increases over the general rate of inflation. These assumptions are unfounded. In addition, the proposal assumes that because BPA underran its expenses in FY 1984 it will* [page 48] *continue to do so without regard for planned spending levels. These assumptions are not appropriate given DOE Order RA 6120.2, which requires that forecasts of O&M expense take into account known factors that are expected to affect the future level of these costs in the cost evaluation period. Therefore, for the purposes of ratemaking, the forecasts of O&M prepared by responsible program officials within BPA are the best forecasts available.*

**Issue #3**

*Has BPA correctly estimated its transmission investments?*

**Summary of Positions**

DOE Order RA 6120.2 requires that the Revenue Requirement Study include additions to the power system planned during the cost evaluation period. BPA, E-BPA-07A, Chapter 14, E-11. Estimates of planned additions are obtained from an analysis of BPA work orders. BPA, E-BPA-01A, 139.

ICP claims that BPA did not justify projected transmission investments for FY 1986 and 1987. ICP alleges that an unexplained increase in BPA planned additions occurs in FY 1987 and that discreprancies [sic] exist between the initial proposal, supplemental proposal, and the FY 1986 Budget. Initial Brief, ICP, B-IC-01, 9-10. ICP suggests that BPA improperly capitalized some of its overhead expenses. Initial Brief, ICP, B-IC-01, 11-12.

ICP suggests that the repayment period for the transmission portion of the FCRPS be shortened from the current 50-year period. This would significantly reduce the level of transmission replacements in the Revenue Requirement study. Initial Brief, ICP, B-IC-01, 8; Reply Brief, ICP, R-IC-01, 6.

**Evaluation of Positions**

The documentation supporting BPA's projected transmission investments for FY 1986 and FY 1987 is found in BPA, E-BPA-07A, Chapter 10. ICP alleges that unexplained increases occurred in BPA plant additions in FY 1987, and that there are in consistencies regarding BPA's projected FY 1987 transmission plant investment. As a basis for its assertion, ICP suggests that BPA's initial proposal projected transmission plant investments in FY 1987 of $159.1 million. Initial Brief, ICP, B-IC-01, 9. This is incorrect. The initial proposal projected FY 1987 transmission plant investments of $104.3 million. BPA, E-BPA-07A, Chapter 10, B-1; BPA, E-BPA-01A, 211.

Next, ICP suggests that BPA's supplemental proposal uses a revised projection for transmission plant investment in FY 1987 of $180.8 million. Initial Brief, ICP, B-IC-01, 10. This is incorrect. BPA's supplemental proposal contains the same figures as the initial proposal for FY 1987 transmission plant investment. The ICP incorrectly refers to BPA's budget for FY 1986 instead of BPA's study and documentation which present the figure for FY 1987 transmission plant investment.
[page 49]

ICP also suggests that a BPA budget document is inconsistent with BPA's projections for transmission plant investment. Initial Brief, ICP, B-IC-01, 10. ICP has apparently used the wrong page of the budget document in its search for projected transmission plant investment. There is no such inconsistency.

ICP's comparison of budget data with plant-in-service comments fails to recognize the distinction between plant-in-service and construction work in progress. BPA's budget must take into account all the funds necessary to meet current construction schedules. In contrast, the rate proposal is based on only the plant-in-service during the cost evaluation period. BPA's Budget for FY 1986 uses the same FCRPS cumulative investment totals that are shown in the supplemental proposal for FY 1985 and FY 1986.

ICP next alleges that BPA's allocation of overhead expense to transmission plant investment is incorrect. Initial Brief, ICP, B-IC-01, 11. ICP alleges that the allocation method found in the BPA budget is arbitrary, unreasonable, and excessive. This argument is misplaced because the budget is not the source of the projected transmission investment used to set rates. The method used by BPA to project such investment was based upon an analysis of work orders of BPA's Office of Engineering and Construction. BPA, E-BPA-01A, 139.

ICP has thus not criticized the actual method used by BPA to project transmission plant investment in the 1985 rate proceeding. No party suggests that an analysis of actual work orders to determine projected additions is inappropriate. Neither has it been demonstrated that the allocation of overhead expenses on those work orders is incorrect. ICP's proposal that the repayment life for the transmission system be shortened is in violation of the requirements set forth in DOE Order RA 6120.2. As noted there, repayment periods of less than 50 years may be established when the facilities involved have useful life expectancies of less than 50 years. BPA, E-BPA-07A, Chapter 14, Page E-8. ICP's proposal that a 25 year repayment period be used is clearly at odds with the 45 year estimated average service life of the transmission system. BPA, E-BPA-07A, Chapter 12, Section D. In addition, certain Corps and Bureau facilities, which have statutory repayment periods of 50 years, have been assigned to the transmission function. If ICP's proposal were implemented it is likely that the Revenue Requirement Study would not provide for full repayment of the FCRTS by the end of the repayment period. This is because the present repayment methodology provides that these projects are not repaid until near the end of their 50 year repayment lives. ICP's proposal, therefore, would violate the cost recovery criteria set forth in DOE Order RA 6120.2. BPA, E-BPA-07A, Chapter 14, Page E-2.

**Decision**

*BPA's initial and supplemental proposals are consistent regarding projected FY 1987 transmission plant investment. BPA's figures are properly documented. BPA's actual method for allocation of overhead expense to transmission plant investment has not been criticized. The analysis of actual*
[page 50] *work orders of BPA is a reasonable source for projecting planned additions to BPA's total investment and no alternative has been offered in the rate case. In conclusion, the estimates of projected BPA investments are reasonable since they are derived from actual work orders and reflect the dates on which plant additions will be placed in service. The ICP*

*proposal that the repayment life of the transmission system be shortened is inconsistent with DOE Order RA 6120.2 and with BPA's estimate of the average service of the transmission system.*

## C. Revenue Requirement Calculation

**Issue #1**

*Should amortization be calculated on a fixed, straight-line basis?*

**Summary of Positions**

The BPA repayment program schedules amortization payments to derive the lowest, levelized revenue requirement necessary to repay all FCRPS costs. BPA, E-BPA-07, 4. A separate hierarchy for transmission and generation amortization is determined by two factors: the date by which each investment must be repaid and the interest rate associated with each investment. This approach is consistent with DOE Order RA 6120.2. Roberts, BPA, E-BPA-5OR, 3.

ICP proposes that BPA replace its repayment program with a standard depreciation accounting approach, incorporating a fixed repayment schedule. ICP claims this would stabilize the flow of revenues for repayment, helping ensure that rates are established in accord with sound business principles. It would be closer to standard utility practice and therefore more understandable. Also, it would match rates with plant replacement in a predictable way. Winter, ICP, E-IC-01, 1-8.

The PPC states that the ICP proposal should not be applied to a Federal power marketing administration. The PPC notes that it would not necessarily solve BPA's repayment problems and that the resulting rate increases could weaken the Pacific Northwest economy. Wolverton and O'Meara, PPC, E-PP-04R, 3.

**Evaluation of Positions**

ICP claims that depreciation accounting would provide a stable flow of revenues to amortize the Federal investment in the FCRPS. Winter, ICP, E-IC-01, 1. This is not necessarily true. There is no particular method for scheduling amortization that provides a stable flow of revenues. Instead, revenues are a function of loads and rates. If projected loads do not materialize or if costs are higher than anticipated, there will be revenue underruns. Roberts, BPA, E-BPA-5OR, 5. BPA can best assure that Federal investments are repaid by basing rates on the best available projections of costs and loads.

[page 51]

ICP also states that depreciation accounting would be closer to standard utility practice and sound business principles. Winter, ICP, E-IC-01, 2. In considering this point, it is important to distinguish between depreciation and amortization. Depreciation accounting -- which is standard utility practice -- provides for systematic allocation of the cost of an asset over its useful life, recognizing that the value of an asset diminishes over time. Amortization--which is a power marketing agency requirement -- is the extinguishment of an obligation by means of periodic payments.  Amortization payments do not necessarily relate to the useful life of an asset but rather to the terms and nature of the obligation.  Roberts, BPA, E-BPA-50R, 3.  The PPC notes that Federal power marketing agencies do not use depreciation in ratesetting.  Also, the PPC questions the ICP assertion that it is generally accepted practice for consumer-owned utilities to use depreciation for ratemaking.  Wolverton and O'Meara, PPC, E-PP-04R, 4-5.

Finally, ICP asserts that standard depreciation accounting will better match plant replacement to rates.  Winter, ICP, E-IC-01, 8.  However, standard plant depreciation would not match rates to BPA's amortization requirements.  This anomaly would occur because BPA's amortization period does not match the time period required by standard plant depreciation.  BPA's current repayment methodology is appropriate for the determination of its revenue requirement given the focus on the existing Federal investments and their amortization pursuant to DOE Order RA 6120.2.  Roberts, BPA, E-BPA-50R, 4.

BPA agrees with PPC that the ICP suggestion would cause some medium- and lower-cost debt to be repaid in advance of higher-cost debt.  Wolverton, O'Meara, E-PP-04R, 7.  This change from existing practice could lead to an increase in rates.  McCullough, Joint Parties, STR 505.

**Decision**

*No particular amortization or depreciation method will guarantee that Treasury payments will be made as scheduled.  If sufficient revenues are collected as planned, the schedule developed by the repayment methodology coupled with BPA's commitment to make amortization payments will assure that all Treasury payments are made on a timely basis.  Based on the arguments presented in this rate proceeding, BPA's repayment methodology is the most appropriate means for determining its revenue requirement.*

**Issue #2**

*Should BPA rely on linear programming to develop the revenue requirement?*

**Summary of Positions**

BPA maintains that the current repayment methodology is an accurate and appropriate means for determining its revenue requirement consistent with the requirements of DOE Order RA 6120.2.  In addition, the repayment methodology has been developed in order to produce numerous detailed reports for BPA's
[page 52] rate proceedings and for the reporting requirements of the Commission.  Roberts, BPA, E-BPA-50R, 5-6.

The Joint Parties advocate a linear programming approach to repayment.  The approach was suggested for two reasons.  First, the parties claim that BPA's repayment methodology does not generate the lowest possible revenue requirement while satisfying BPA's repayment criteria.  Second, the Joint Parties claim that the linear programming approach is easier to understand than BPA's current methodology.  Wolverton, McCullough, and Young, Joint Parties, E-JP-01, 6-9.

OPUC and WUTC agree that BPA should implement the linear programming technique for establishing the revenue requirement. Initial Brief, OPUC/WUTC, B-OP/WU-01, 5-7.

**Evaluation of Positions**

The first criticism raised by the Joint Parties is that BPA's current methodology overstates the revenue requirement. Using a linear programming model, and supplied with data by BPA, the Joint Parties found that BPA's revenue requirement could be lowered by at least $4 million. Wolverton, McCullough, and Young, Joint Parties, E-JP-01, 9. However, the linear programming models used by the Joint Parties are deficient in that both the interest credit and interest expense are incorrectly calculated. Roberts, BPA, E-BPA-50R, 5. In addition, the Joint Parties' models do not produce a levelized revenue requirement. Young, Joint Parties, STR 439. Furthermore, the Joint Parties submitted numerous alternative models with varying inputs, assumptions, and results. Young, Joint Parties, STR 437.

In order to check the Joint Parties' assertion that BPA's methodology results in an increased revenue requirement, BPA used its own linear programming model with assumptions based on the supplemental proposal to determine BPA's revenue requirement. The results of this run were then compared with the results of BPA's current methodology. The difference between results of the two methodologies was less than .01 percent.

With respect to the complexity of the current repayment methodology, BPA has presented numerous studies and testimony explaining this methodology in each rate case under the Northwest Power Act. In addition, detailed and summary repayment reports have been developed to describe the methodology and results. Considerable work would have to be performed with the linear programming approach in order to produce all the reports necessary to meet the Commission's rate filing requirements. Roberts, BPA, E-BPA-50R, 6.

**Decision**

*The Joint Parties' assertion that BPA's current repayment methodology overstates BPA's revenue requirement is unsubstantiated. The accuracy of BPA's current methodology in determining the revenue requirement consistent with BPA's repayment criteria has been demonstrated in this proceeding and has been verified by comparison with a linear programming model. The proposed linear programming models did not produce a levelized revenue requirement.*
[page 53] *The relative simplicity of a linear programming model does not warrant a change at this time, given the difficulty of producing materials to meet the Commission's rate filing requirements. BPA will, however continue to evaluate the use of a linear programming model for the next general rate case.*

**Issue #3**

*Are replacements projected correctly in the Revenue Requirement Study?*

**Summary of Positions**

Since the Revenue Requirement Study determines the costs of the FCRPS sufficient to maintain its current level of capacity throughout the repayment period, plant replacements are included throughout the repayment period consistent with DOE Order RA 6120.2. Roberts, BPA, E-BPA-50R, 9. For the transmission system, future replacements are estimated using the Iowa survivor curve technique. Generation replacements are estimated using project specific mortality characteristics. BPA, E-BPA-03A, Chapters 11 and 12. The Joint Parties claim that BPA's repayment studies treat generation and transmission replacements inconsistently. They assert that the generation repayment study assumes that a plant does not age over time and therefore that replacement costs for the cost evaluation period are repeated throughout the useful life of the plant. In contrast, they claim that the transmission repayment study assumes that a plant does age over time. As a solution to this perceived inconsistency, the Joint Parties propose that each future year beyond the cost evaluation period use the same replacement stream as was developed for the cost evaluation period. Wolverton, McCullough, and Young, Joint Parties, E-JP-01, 13-14; E-JP-01S, 4.

ICP suggests that BPA is unable to support any of the transmission and generation replacement amounts in its Revenue Requirement Study. ICP supports the Joint Parties' claim that the proposed reduction in the transmission replacements will result in a corresponding reduction in the revenue requirement of about $21 million. Initial Brief, ICP, B-IC-01, 8.

ICP states that BPA has conducted no studies to separate historical replacements and additions from historical investment. Second, ICP claims that BPA has not complied with Commission regulations requiring a separate identification of replacements and additions. Third, ICP claims that BPA projects that it will not need to replace any of its existing plant prior to FY 1988. Reply Brief, ICP, R-IC-01, 4-5.

**Evaluation of Positions**

With regard to the Joint Parties' first assertion, the generation and transmission studies each assume an aging plant after the cost evaluation period by reflecting increasing amounts of replacements for older projects. However, projected replacements for generation and transmission are calculated differently in that they contain different measures of the way in which the aging of plant occurs. Roberts, BPA, E-BPA-50R, 10.

[page 54]

The proposal put forward by the Joint Parties to address the perceived inconsistency would understate projected replacements because the replacements in the cost evaluation period are lower than replacements throughout the repayment period. The Joint Parties' proposal also ignores the aging of plant over time because it would consider replacements only in the cost evaluation period. Roberts, BPA, E-BPA-50R, 10-11.

The Documentation for Revenue Requirement Study contains supporting workpapers for both transmission and generation replacements. BPA, E-BPA-07A, Chapters 11 and 12. These workpapers are supported by studies performed by the appropriate Federal agency (Bureau of Reclamation, Corps of Engineers, BPA). The study performed by BPA, which serves as the basis for the transmission replacement estimates, is the 1983 Depreciation Study provided in Chapter 12 of the Documentation.

ICP alleges that BPA conducted no studies to determine historical replacements. A historical determination of replacements is not necessary in order to project future replacements. However, BPA's projection of replacements, as well as those of the Corps and Bureau, do reflect historical trends. BPA extensively documented the basis for its projections. BPA, E-BPA-07A, Chapters 11 and 12. While separate historical documentation was not necessary in order to make the projections and in fact was not avoidable, BPA made an effort to gain such information. This issue was fully discussed in BPA testimony. Roberts, BPA, E-BPA-21, 7. As noted there, the Commission's regulations require a separate identification of replacements and additions in Statements A through F as part of its final rate approval criteria. BPA sent letters to the Corps and the Bureau on February 10, 1984, to notify the agencies that additional investment information would be required by the Commission's new filing requirements. BPA requested the Corps and the Bureau to account for all historical and future investments showing annual changes broken down by initial investments, additions, and replacements. Both the Corps and Bureau notified BPA that they could not provide the historical annual breakdown of investments requested by BPA because their historical records no longer exist. BPA, therefore, had to develop its own estimates of this information. This was an extensive and time consuming task that was not completed until late in the rate proceeding. BPA advised the parties that BPA's historical estimates would be provided in BPA's submittal of Statements A through F, which will be filed with the Commission as part of BPA's final rate proposal. Roberts, BPA, E-BPA-21, 7. Consequently, BPA's filing of Statements A through F should contain sufficient information to allay the ICP's concerns.

ICP alleges that BPA admits it has not complied with FERC regulations. This is incorrect. The regulations require a breakdown of historical and projected data for purposes of BPA's filing with the Commission. 18 CFR 300.11(a). So long as BPA's breakdown is provided in BPA's filing with the Commission, BPA has complied with the regulations. As noted above, this information is being provided in Statements A through F.

The ICP claims that BPA projects that it will not need to replace any of its existing plant prior to FY 1988. This is incorrect and a
[page 55] mischaracterization of BPA's projections. Prior to the 1985 filing of Statements A through F, replacements, though they occurred and were therefore included in the initial plant, were not separated from initial plant. Replacements will be separately identified in Statements A through F. While replacements have not been shown separately prior to this filing of Statements A through F with the Commission, they were assigned the appropriate interest rate. As a result, the changes embodied in Statements A through F will affect only the format of the data, not the level of the revenue requirement. Roberts, BPA, E-BPA-21, 7.

**Decision**

*BPA's methodology for incorporating replacements in the Revenue Requirement Study is appropriate. Currently, replacements for the transmission and generation systems are projected based on the age of the equipment. However, BPA cannot require the Corps of Engineers and Bureau of Reclamation to use any particular technique for incorporating the effect of aging within their calculation of replacements. BPA's projected replacements are fully documented,* *including documentation reflecting historical trends. BPA has complied with Commission regulations by providing a separate identification of replacements in Statements A through F. BPA has demonstrated that it will need to replace certain existing plant prior to FY 1988.*

**Issue #4**

*Should new debt be incurred when Federal investments bearing a lower interest rate are being repaid before their due dates?*

**Summary of Positions**

From FY 1985 through FY 1987 new conservation investments in the FCRPS are projected to be made at interest rates of approximately 12 percent. During the same period amortization payments are scheduled on investments bearing interest rates of 10 percent or less. This follows the requirements of DOE Order RA 6120.2, which establishes a hierarchy of payments. All expenses such as O&M, purchase and exchange power, interest expense, and amortization of bonds must be repaid first. Next, "[r]emaining revenues are available for amortization and shall be applied first to unpaid or deferred annual expense, if any, and then to the Federal investment." BPA, E-BPA-07A, Chapter 14, E-5.

None of the lower interest rate investments that are being amortized must be retired within FY 1985 through FY 1987. PGP notes that BPA's annual interest expense could be lowered by applying internally generated funds towards the new conservation investment occurring in FY 1985 through FY 1987 rather than toward this lower interest debt. Winterfeld, PGP, E-PG-03, 3; Reply Brief, PGP, R-PG-01, 4-5. PGP claims that the assumed application of revenues toward amortization in FY 1985 through FY 1987 is at odds with (1) the criteria of repaying highest interest bearing investments first;
[page 56] (2) the application of revenues after the cost evaluation period; and (3) BPA's own financial policy. Reply Brief, PGP, R-PG-01, 5.

**Evaluation of Positions**

DOE Order RA 6120.2 provides a hierarchy of how revenues are to be applied. The order is silent on the application of revenues to new investments. BPA, E-BPA-07A, Chapter 14, E-5. However, one may infer that the application of revenues to new investments is lower in the hierarchy of applications than those uses of revenues expressly mentioned in the regulation. The PGP proposal is inappropriate given the Federal Energy Regulatory Commission's concern that the practice of continually postponing amortization payments may lead to the "bow wave" phenomenon. A "bow wave" may occur if amortization payments are continually deferred with an ever-increasing level of annual payments required with each succeeding rate filing (48 F. Reg. 28,317). As discussed by the Commission, this would have the effect of continually pushing BPA's repayment commitment to future ratepayers. If the PGP proposal were instituted over a long period, the potential for a "bow wave" would be exacerbated.

PGP claims that BPA's criticisms of the PGP proposal are unfounded. First, PGP alleges that DOE Order RA 6120.2 does not distinguish between existing and new investment. Therefore, PGP implies that DOE Order RA 6120.2 allows revenues to be applied to both existing and new investments indiscriminately. Reply Brief, PGP, R-PG-01, 4-5. This interpretation is incorrect. The focus of the order regarding priority of revenue application is clearly amortization. As stated there, "[r]emaining revenues are available for amortization and shall be applied first to unpaid or deferred annual expenses, if any, and then to the Federal investments." BPA, E-BPA-07A. Chapter 14, Page E-5. Amortization can only occur after the associated plant is placed in service. Therefore, funds cannot be applied to new investments prior to making amortization payments. It must be reiterated that the repayment of the Federal investment can occur only after the associated plant is placed in service. In addition, if this investment is financed by a bond, no principal payments can be made during the first 5 years of the bond's life. BPA, E-BPA-07, 42. Therefore, the concept of paying highest interest-bearing investments first, whenever possible, has not been violated.

PGP next claims that application of revenues towards amortization in FY 1985 through FY 1987 is contrary to application of revenues after the cost evaluation period. Reply Brief, PGP, R-PG-01, 5. PGP is incorrect. No amortization can be applied at any time to bonds during the first five years after the bond is issued. Id. Amortization may be applied to investments funded by appropriations during the same fiscal year, however. An example of this occurring during the FY 1985 to FY 1987 period is documented in BPA supplemental testimony. Roberts, BPA, E-BPA-21S, Attachment 5, page 1. Therefore, the application of amortization during the cost evaluation period is not inconsistent with the application of revenues after that period.

PGP alleges that BPA's application of revenues is inconsistent with BPA's statement of its financial policy. PGP incorrectly states that BPA testimony [page 57] refers to repayment policy. Reply Brief, PGP, R-PG-01, 5. On the contrary, BPA’s testimony addresses cash management policies. BPA’s cash management policies treat the financing of new investment as only one of three possible options. BPA must retain its flexibility to choose among its cash management options when excess funds materialize. Therefore, PGP's allegation of an inconsistency between application of revenues and BPA's repayment policy is incorrect.

PGP claims that no contradictory testimony was offered in response to their allegation that the implementation of their proposal would not reduce or postpone amortization payments to the Treasury. It is not necessary to offer contradictory testimony where testimony is rebutted by the record and simple logic. PGP fails to refute the fact that their proposal would exacerbate the "bow wave" phenomenon described by the Commission. BPA and PGP agree that the two main sources of cash for BPA are funds provided from operations and from borrowings. Winterfeld, PGP, STR 856. PGP then concludes that amortization would not be reduced or postponed by assuming that BPA has the freedom to reduce bonds in the year of issue by applying funds to new investment instead of scheduling amortization of investments bearing lower interest rates. Winterfeld, PGP, STR 859-860. The PGP assumption is incorrect for the following reason. When BPA issues a bond to the Treasury, BPA may elect to place a 5-year no call provision on the bond. This means that no payments of principal can be made during the first 5 years after the bond is issued. BPA, E-BPA-07, 42. Currently, all of BPA’s bonds have a 5-year no call provision and the Treasury does not issue bonds with less than a 5-year no-call provision. Therefore, BPA does not have the discretion to retire bonds during the year of issue.

PGP offers another possibility, whereby BPA would take cash available at year-end and use the funds to pay for new investment directly in that year rather than issue a new bond. Winterfeld, PGP, STR 860-861. What PGP fails to realize is that BPA considers its scheduled amortization to be a firm commitment. If the funds available at the end of the year are used to finance directly new investments instead of making amortization payments to the Treasury, the size of the amortization payment in that year must be affected. PGP implies that there will be no effect on BPA's amortization payments in that year. Winterfeld, PGP, STR 859. This is not correct; if planned borrowings do not occur, then the only other source of cash to finance new plant-in-service are funds available for amortization. If these funds are thus used the funds for amortization would necessarily be reduced. To carry the example further, if the planned investment were entirely funded from funds available for amortization, no amortization would occur in that year. A continuation of this policy year after year would lead to the "bow wave" foreseen by the Commission.

**Decision**

*The Revenue Requirement Study represents a balance between cost minimization and the need to meet all obligations of the FCRPS. BPA's application of revenues toward amortization is consistent with BPA's repayment* [page 58] *policy. BPA views its scheduled amortization payments as an important commitment. The suggestion that BPA plan to forego amortization payments when interest rates are high is not in accord with this commitment.*

**Issue #5**

*How should the interest credit be calculated?*

**Summary of Positions**

BPA calculates an interest credit as an offset to interest expense consistent with applicable legislation (P.L. 93-454) and DOE policy (Order RA 6120.2). BPA, E-BPA-07A, Chapter 14, E-11. The interest credit is calculated on the average cash balance that BPA is estimated to have on deposit with the U.S. Treasury. At issue are the costs that affect the average balance. PGP states that "BPA’s calculation of interest expense offset overlooks three expense items not paid until year-end." These three items are: (1) the deduction of the O&M expense paid to the Bureau and the Corps; (2) the deduction of the cash lag adjustment; and (3) the deduction of investment service coverage. Winterfeld, PGP, E-PG-03, 12.

**Evaluation of Positions**

PGP first addresses the deduction of Corps and Bureau O&M expenses in the interest credit calculation. Winterfeld, PGP, E-PG-03, 12. BPA agrees that funds paid to the Treasury for Corps and Bureau O&M should not be deducted when calculating the interest credit because these funds are kept on deposit with the Treasury until the end of the fiscal year.

PGP also suggests that the cash lag adjustment should not be deducted in the interest credit calculation because these revenues are received throughout the year and should be included in the calculation of interest revenues. Winterfeld, PGP, E-PG-03, 13. While it is correct that the revenues from the cash lag adjustment are received throughout the year, it is necessary to use those funds throughout the year to meet the increase in net working capital requirements. Roberts, BPA, E-BPA-50R, 2. Therefore, the cash lag adjustment does not increase the average balance BPA has on deposit with the Treasury. Instead, funds from the cash lag adjustment are used to maintain the average balance that BPA might have on deposit if cash receipts did not lag behind cash expenditures. Roberts, BPA, E-BPA-50R, 2.

PGP claims that it is standard utility practice to measure the average lag (or lead) throughout the year. Reply Brief, PGP, R-PG-01, 6. This is not an appropriate alternative, in that the purpose of the cash lag adjustment is to ensure adequate cash on hand to make Treasury payments at year end. An average lag would not necessarily satisfy this condition because the average lag does not necessarily equal the lag at the end of the year.

Finally, PGP suggests that investment service coverage (ISC) should not be deducted in the interest credit calculation because these revenues are
[page 59] received throughout the year and should be included in the calculation of interest revenues. Winterfeld, PGP, E-PG-03, 13. This proposal is inappropriate; ISC does not contribute to an increase in the average cash balance. See discussion *infra*. ISC is used to finance new investments directly, Meyer, BPA, E-BPA-19, 13, and thus has no effect on the average cash balance. Roberts, BPA, E-BPA-50R, 3.

**Decision**

*Consistent with the recommendation of PGP, the Corps and the Bureau O&M expense is not deducted from the interest credit calculation in the final Revenue Requirement Study. The cash lag adjustment does not increase the average cash balance and is therefore deducted from revenues in the calculation of the interest credit. BPA plans to retain ISC as a deduction from revenues in the calculation of the interest credit. This is fiscally prudent and will have no effect on the average cash balance. Any other application of ISC in the calculation of the interest credit may cause the revenue requirement to be understated.*

## D. Revenue Requirement Adjustments

**Issue #1**

*Should 7 1/2 percent of new construction and conservation plant in service be added to the revenue requirement to provide an investment service coverage?*

**Summary of Positions**

In BPA's initial 1985 rate proposal, ISC was determined by multiplying the incremental additions to projected conservation and construction plant-in-service in FY 1986 and FY 1987 by

7 1/2 percent. Projected bond sales for conservation and construction were reduced by the ISC amount calculated in this manner.

In the supplemental proposal, the method for determining ISC remained the same. However, projected bond investments were not reduced. This change was made because, given an initial interpretation of accounting principles, BPA may be required to expense conservation and transmission plant equal to the amount of ISC. BPA's treatment of the ISC in the supplemental proposal is consistent with viewing the ISC as an annual cost or insurance-type premium reflecting the risk associated with BPA's ability to meet its interest obligations. If the cost of the plant were expensed, BPA's ability to borrow these funds might be foreclosed, thus eliminating the intended flexibility. Roberts, BPA, E-BPA-21S, 4-5.

LADWP agrees with BPA's ISC proposal. LADWP notes the common practice for private and publicly owned utilities to establish rates that recover some multiple of their actual debt service (interest and principal payments). For [page 60] example, LADWP's bond covenant protects bondholders by requiring that adjusted net income be a minimum of 1.25 times the highest future year debt service for existing bonds. Parmesano and Whitney, LADWP, E-LA-01, 26-27.

Several parties allege that ISC would constitute an unlawful contingency allowance, claiming that ISC would never be credited to BPA's costs. Initial Brief, Joint Parties, B-JP-01, 24-27; Initial Brief, ICP, B-IC-01, 13; Initial Brief. APAC, B-PA-01, 17; Initial Brief, PGP, B-PG-01, 6. The Joint Parties, PGP, APAC, and WUTC/OPUC state that ratepayers would receive no benefit from ISC under BPA's supplemental proposal. In particular, they object to the fact that borrowings are not reduced by the amount of ISC. Winterfeld, PGP, E-PG-03S, 3; Wolverton, McCullough and Young, Joint Parties, E-JP-01S, 4; Initial Brief, WUTC/OPUC, B-OP/WU-01, 7.

A number of parties also allege that implementing an ISC would not bring BPA closer to the industry standard. Initial Brief, Joint Parties, B-JP-01, 26; Initial Brief, PGP, B-PG-01, 7; Initial Brief, APAC, E-PA-01, 16. WUTC and OPUC state that ISC has no counterpart in the regulation of investor-owned utilities. Initial Brief, OPUC/WUTC, B-OP/WU-01, 7. The Joint Parties argue that the ISC is not a utility standard practice applicable to BPA because BPA does not incur the same risks that utilities do. Reply Brief, Joint Parties, R-JP-01, 24. APAC is unconvinced that the ISC is a sound business practice followed by other utilities. Reply Brief, APAC, R-PA-01, 16. APAC and PGP state that BPA's analogy to investor owned and public utilities is inappropriate. They believe that the interest and amortization payment on Treasury investments requires or deserves no analogous protection. Initial Brief, APAC, B-PA-01, 16-17; Initial Brief, PGP, B-PG-01, 7-8. APAC asserts that BPA ratepayers receive no benefits from BPA's collection of its capital investment through rates. Reply Brief, APAC, R-PA-01, 06.

WUTC and OPUC suggest that the 7 1/2 percent figure is not substantiated by any analysis. Reply Brief, OPUC/WUTC, R-OP/WU-01, 4. The Joint Parties claim that the selection of 7 1/2 percent is arbitrary because it has no rational relation to BPA costs. Reply Brief, Joint Parties, R-JP-01, 24.

APAC suggests that short-term borrowing be used instead of ISC. Cook, APAC, E-PA-03, 7-10. Finally, PGP alleges that the ISC would be in effective in making BPA financially stable and that other mechanisms could be designed. Reply Brief, PGP, R-PG-01, 7.

**Evaluation of Positions**

The Joint Parties have developed a broad, simple argument relating to BPA's revenue requirement issues. Whenever BPA has forecast a cost exceeding what the Joint Parties believe is appropriate, the amount by which the BPA estimate differs from the Joint Parties' estimate is characterized as a "contingency allowance." The Joint Parties, having characterized virtually every revenue requirement issue as involving a contingency allowance, then rely on a legal argument to support their proposition that contingency allowances are unlawful. The Joint Parties conclude that all BPA's revenue
[page 61] requirement decisions are unlawful. However, BPA's revenue requirement decisions do not result in contingency allowances in BPA's rates. Nevertheless, the legal argument of the Joint Parties must be addressed.

Several parties allege that BPA's supplemental ISC proposal would be an unlawful contingency allowance since it would not be credited against BPA's costs. Initial Brief, Joint Parties, B-JP-01, 24-27; Initial Brief, ICP, B-IC-01, 13; Initial Brief, APAC, B-PA-01, 17; Initial Brief, PGP, B-PG-1, 6. To support their argument against contingency allowances, the Joint Parties and APAC suggest that a draft version of the Northwest Power Act provided that rates shall be based on "the Administrator's total system costs including contingencies." S. Rep. No. 96-272, 96th Cong., 1st Sess. 9 (1979). They then note that the words "including contingencies" were eliminated by the House Commerce Committee. From this they conclude that BPA has thus been prohibited from including contingencies in its rates. This argument is unconvincing.

The scant attention given to the topic of contingencies in the Northwest Power Act's legislative history is not particularly illuminating. The language of the bill which was not enacted by Congress provided that rates must be based on "the Administrator's total system costs including contingencies." Had this provision been adopted, BPA would have been mandated to reflect contingencies in its rates and FERC could not approve rates which failed this test. Deletion of the phrase "including contingencies" simply changes contingency allowances from a mandatory rate provision to a permissive one. Nothing in the Northwest Power Act prohibits including contingencies in rates. Consequently, while the Administrator is not *required* to include contingencies in his rates, he *may* do so where he finds it appropriate in the exercise of his broad discretionary authority.

In their Reply Brief, the Joint Parties argue that the contingency language in S.885 was directed to the Commission, which would not have been able to approve BPA rates absent a provision for contingencies. Thus, the Joint Parties argue, deletion of the words "including contingencies" was intended to deprive the Commission of the authority to approve BPA rates which reflect contingencies. The Joint Parties ignore the fact that the Commission is only empowered to approve or reject BPA rates. 16 U.S.C. §839e(a)(2). The Commission could not remake BPA's proposed rates to include a provision for contingencies, if BPA had neglected to do so. Therefore, the bill can only be read to have *required* BPA to include contingencies in the rates it submits to the Commission for review. Deletion of the phrase "including contingencies" therefore removed the absolute requirement that BPA include contingencies with no connotation that contingencies are barred as a matter of law. Rather, the deletion provided more administrative flexibility to the BPA Administrator who can adopt a contingency allowance when he finds it to be a "sound business principle." 16 U.S.C. §839e(a)(1).

The Joint Parties allege that the power to include contingencies in BPA's rates cannot be implied where the words "including contingencies" were purposely omitted from the statute. However, the principles of statutory [page 62] construction cited by the Joint Parties advise caution against literal application. 2A Sands, Sutherland Statutory Construction §48.18 (4th ed. 1984). While adoption of an amendment is evidence of intent to change a bill, the amendment may have been adopted (i.e., the provision deleted) because it was unnecessary. Id.

It is clear that the authority to reflect contingencies in rates exists under pre-existing statutory directives. Section 9 of the Federal Columbia River Transmission System Act, 16 U.S.C. §8389, provides that BPA's rates are:

> …subject to confirmation and approval by the Federal Power Commission, and shall be fixed and established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers *consistent with sound business principles*… [Emphasis added].

The Flood Control Act of 1944, 16 U.S.C. §3825s, also requires that BPA's rates must be "consistent with sound business principles."

In reviewing BPA rates, the Federal Power Commission (FPC, predescessor [sic] to the Federal Energy Regulatory Commission) has held that the "sound business principles" requirement of the Flood Control Act of 1944 and the Federal Columbia River Transmission System Act provided BPA with the statutory authority to include contingencies in rates. The holding of the FPC is unequivocal:

> In applying that standard to the matter which is now before us, we conclude, from the staff's unrefuted evidence, that while BPA must increase its revenues by 24% to continue to meet its obligations to the United States Treasury for the government's costs of generating, purchasing and transmitting electric energy in the Federal Columbia River Power System, *the additional 3% proposed by BPA for unforeseen contingencies is consonant with the "good business practices "standard of the statute*. (Emphasis added).

*Bonneville Power Administration*, 54 FPC 808, 811 (1975).

The construction of BPA's organic statutes by BPA and the Commission is entitled the substantial deference. *Aluminum Co. of America v. Central Lincoln PUD*, 104 S.Ct. 2472 (1984). There is simply no question that BPA has the authority under the Flood Contol [sic] Act of 1944 and the Federal Columbia River Transmission System Act to provide for contingencies in its rates. In fact, the very same statutory standard of "sound business principles" was expressly incorporated into section 7(a)(1) of the Northwest Power Act, which provides that "[r]ates shall be established and, as appropriate, revised to recover, *in accordance with sound business principles*, the costs associated with the acquisition, conservation and transmission of electric power…" (emphasis added). Thus, the "sound business principles" standard of the Flood [page 63] Control Act, the Federal Columbia River Transmission System Act, and the Northwest Power Act authorize the inclusion of contingency allowances in BPA's rates.

Ignored by the Joint Parties is section 7(g) of the Northwest Power Act, 16 U.S.C. §839e(g), which gives BPA the authority to "equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including … uncontrollable events…" For utilities, like BPA, that establish rates on a projected test year, this is accomplished through a contingency allowance. Section 7(g) thus is a clear-cut authorization for contingency allowances. Recognizing the uncontrollable nature of some aspects of BPA's revenues and costs simply follows the ratemaking principle established by the FPC. *See Bonneville Power Administration*, 54 FPC 808, 811 (1975). Any issue of whether this principle is "generally accepted" is a question of policy -- not law -- for BPA to decide. In the first instance and for the Commission to review.

As another element of their argument against contingency allowances, the Joint Parties cite congressional testimony presented by Commission staff member William W, Lindsay (erroneously identified as the Commission's chairman). Mr. Lindsay testified regarding the ratemaking provision of S.885:

> This section also provides for contingencies as an element in the Federal rate making process. *An allowance for contingencies has not customarily been authorized* in rates of Federal or investor-owned utilities. A contingency normally would be expected to be used to offset future operating costs that could not be defined or justified at the present time. The Federal rate making process allows a power marketing agency such as BPA to file for increased rates when unexpected changes in its cost of providing service occur and to estimate anticipated increases in costs so long as the estimates are justified. [Emphasis supplied.]

Hearings on H.R. 3508 and H.R. 4159 before the Subcomm. on Energy and Power of the House Comm. on Interstate and Foreign Commerce, 96th Cong., 1st Sess. 230 (1979) (Statement of William W. Lindsay). Two observations about the Lindsay testimony make it clear that it carries no connotations that contingency allowances should be prohibited -- at least not the type of contingency allowances alleged to exist in BPA's proposed rates.

First, Mr. Lindsay stated that "[a]n allowance for contingencies has not customarily been authorized." This is not a statement of legal authority. Instead, it describes Commission policy or custom. Implicit in the statement is the conclusion that statutory authority exists to change that policy. Indeed, it is clear that the Commission had previously allowed BPA to include a-

contingency provision in its rates. *Bonneville Power Administration*, *supra*, 54 FPC at 811. Furthermore, ratemaking is not generally constrained to any
[page 64] single set of constructs or rules. *See Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).

Second, Mr. Lindsay's reference to "costs that could not be defined or justified at the present time" has no relevance to the 1985 BPA rate case. It appears that Mr. Lindsay was criticizing attempts by utilities to recover their total costs plus an adder -- something in the nature of an attrition allowance. *See Southern California Edison Co. v. FERC,* 686 F.2d 43, 46-47 (D.C. Cir. 1982). That is not the case here. BPA has provided justification for every component of its revenue requirement.

In an argument related to their use of the Lindsay testimony, the Joint Parties quote a floor statement of Rep. Ullman observing that "[a]t present, FERC does not permit BPA to include in its rates any 'allowance for contingencies,' even in order to insure timely repayment to the treasury." 126 Cong. Rec. H9844 (daily ed. Sept. 29, 1980). This isolated statement is simply erroneous. FERC has never addressed the issue of contingency allowances in BPA rates. However, the FPC affirmatively held that such allowances were sound business principles in accord with governing statutes. In any event, Mr. Ullman's statement speaks more to the Commission's policy than to its legal authority.

The Joint Parties next cite to section 8(d)(2) of the House Interior Committee version of S.885, which included an interest penalty for BPA's failure to meet Treasury repayment obligations regardless of cause. This, provision was amended prior to enactment to provide that the penalty would not apply when underpaying the Treasury was due to events beyond the control of the Administrator. *See* 16 U.S.C. §839k(d)(4). The Joint Parties argue that the exception to the interest penalty provision would not have been necessary if the Administrator were able to provide for contingencies in rates. This argument is flawed for two reasons.

First, the House Interior Committee expressly recognized BPA's legal authority to make provision for contingencies in the portion of its S.885 report devoted to discussion of section 8 (d)(2):

> The Committee included this penalty provision in S.885 so as to provide BPA with an incentive to keep its repayment obligations current. However, the Committee is aware that BPA's revenues fluctuate significantly in response to fluctuations in annual streamflows. Consequently, the Committee believes it would be appropriate for BPA to include as a cost in its rates an allowance to cover the possibility of less than average water conditions so as to enable it to make timely repayments necessary to avoid the interest rate penalty. (Emphasis added.)

H.R. Rep. 976 (Pt. II), 96th Cong., 2d Sess. 54 (1980). This was an observation about the bill which, on the question of contingency allowances, does not differ from the Northwest Power Act. The quoted passage confirms BPA's pre-existing authority to include contingency allowances in rates.
[page 65]

Second, a contingency allowance merely reflects projected uncertainties in revenues and costs over the period rates remain in effect.  As a projection, it may not be borne out by actual revenues and costs.  Existence of a contingency allowance still leaves the possibility of major cost overruns or revenue underruns that would leave BPA unable to repay the Treasury.  The exception to the interest penalty provision of section 8(d)(2) would apply to such major unanticipated events not covered by a contingency allowance.

The remainder of the Joint Party arguments are, at best, oral legislative history written for the first time in their brief.  However, these speculative statements why contingency allowances should or should not be included in rates cannot outweigh the conclusion of this Record of Decision that such allowances are authorized by the "sound business principle" standard of all BPA's organic statutes.

Aside from this legal question, however, it is clear that the parties' major concerns about ISC are resolved by use of the concept developed in BPA's initial proposal.  As noted above, in the initial proposal BPA forecast the application of ISC to finance new investment directly, thereby reducing projected borrowings.  The final proposal adopts the approach taken in the initial proposal.  Clearly, this is not a contingency allowance.

Joint Parties, APAC, and WUTC/OPUC all maintain that the ISC is not standard utility practice and that it would not bring BPA closer to the industry standards.  BPA has never maintained that it mirrors an IOU or that the specific features of the ISC are standard for the utility industry.  Instead, BPA has argued that the concept behind the ISC is universally accepted within the utility industry and serves a vital function.  Meyer, BPA, E-BPA-19, 10-13.  No party has refuted this fact.  LADWP, in fact, supports BPA on this issue.  Parmesano and Whitney, LADWP, E-LA-01, 26-27.

Most utilities are financed by a combination of debt and equity.  Historically, BPA has been financed solely from appropriations or debt.  ISC, for BPA, is a component of the revenue requirement which is used to help ensure that funds will be available to revenue finance a certain amount of incremental investments.  BPA has taken this step in order to reduce its dependency on debt financing.  The ISC provision also decreases BPA's risk of not meeting its Treasury payments.

WUTC/OPUC and Joint Parties suggest that BPA has not substantiated the 7 1/2 percent figure for investment service coverage.  This is incorrect.  BPA noted in its 1983 rate adjustment proceedings that BPA might in future years gradually increase the 5 percent amount of capital investment financed through rates.  Meyer, BPA, E-BPA-19, 12.  BPA's decision to introduce revenue financing was tempered by the conditions of the economy at that time.  For the 1985 rate proposal, in light of the somewhat improved economy, BPA modestly increased its investment service coverage from 5 percent to 7 1/2 percent in order to provide for a greater level of revenue financing of investment.  Meyer, BPA, E-BPA-19, 12.  Given the current economic situation and BPA's need to provide for fiscal soundness, the 7 1/2 percent figure represents a moderate choice within the possible bounds.

[page 66]

PGP states that the records of the REA suggest that Times Interest Earned Ratio (TIER) and Debt Service Coverage (DSC) for public utilities have averaged 1.13 and 1.19 respectively since

1978. Over the same period, and using the same definitions, BPA's DSC and TIER have averaged significantly less than the comparable statistics for public utilities for the same time period. Initial Brief, PGP, B-PG-01, 8. Therefore, when judged by these standards, BPA's financial performance from 1978 to 1982 was not as good as the public utilities in the sample.

APAC suggests that BPA should use short-term borrowing instead of ISC. Cook, APAC, E-PA-03, 7-10. However, BPA's short-term borrowing ceiling of $250 million is nearly exhausted. Meyer, BPA, STR 177, 269. ISC would be used to finance investments from internally generated funds, attendant reductions in bonds, thereby reducing interest and amortization expense. Moreover, it seems unlikely that APAC's member firms would ever suggest, to any entity other than a Federal power marketing agency, that short-term debt be completely exhausted as a source of capital before resorting to internally generated funds. The APAC proposal would maximize the risk that BPA would not meet its Treasury obligations. APAC and PGP believe that since BPA is a Federal agency the interest and amortization payments to the Treasury do not need to be protected. This view is short-sighted. If BPA has to defer an interest payment, a market-based interest rate is assigned to the deferred payment. If BPA were to miss an amortization payment, the Secretary of the Treasury could increase by up to 1 per centum the interest rate applicable to the outstanding bonds issued by the Administrator during such fiscal year. 16 USC § 839i (d)(4). APAC maintains that BPA ratepayers would receive no benefits from the ISC. This is incorrect. In addition to the savings that will result if the above penalties are not imposed, BPA's interest expense will also be reduced as a result of the ISC. This reduction will occur due to increased interest income, a decrease in the amount of bonds issued, or an increase in amortization.

Finally, PGP argues that BPA has not demonstrated that ISC is the most effective rate mechanism to avoid revenue shortfalls similar to those experienced by BPA in the past. Reply Brief, PGP, R-PG-01, 7. While there may be numerous means of approaching the problem of revenue underrecoveries, BPA has demonstrated that ISC is a reasonable way to achieve some additional measure of financial soundness. Meyer, BPA, E-BPA-19, 12.

**Decision**

*The need for ISC stems from the fact that BPA is a self-financing agency of the Federal government that is able to generate funds only through rates or borrowings. It is a sound business practice to attempt to meet a portion of capital requirements with internally generated funds. BPA includes an ISC as developed in the initial proposal. If events occur as anticipated, BPA plans to finance a portion of new investments with revenues. The incorporation of ISC in this manner is an important step toward providing fiscal soundness for BPA.*

[page 67]

**Issue #2**

*How should the cash lag be calculated?*

**Summary of Positions**

In its 1982, 1983, and 1985 rate proposals BPA incorporated a cash lag adjustment in the determination of its revenue requirement. The cash lag adjustment converts the revenue requirement from an accrual to a cash basis. Cash lags are a function of the timing of both revenues and expenses. Revenue lags reflect the delay between the time revenue is earned and the time cash payment is received. Expense lags reflect the difference between the time an expense is incurred and the time payment must be made. The *net* cash lag is the difference between total revenue lag in dollars and total expense lag in dollars at the end of each fiscal year. The cash lag *adjustment* to the Revenue Requirement Study represents the difference between the net cash lag out of the current year and the net cash lag into the current year from the previous year. BPA's Revenue Requirement Study is based on budgeted program cost estimates prepared on an obligation basis and a revenue forecast prepared on an accrual basis. However, BPA must plan year-end Treasury cash payments at a specific point in time: the last day of BPA's fiscal year. Roberts, BPA, E-BPA-21, 11-12. The cash lag adjustment is used to ensure that BPA will have sufficient cash on hand to transfer the scheduled amortization payment to the Treasury at year end. Winterfeld, PGP, E-PG-03, 11-12.

APAC raises a number of criticisms of the cash lag. APAC states that the cash lag should not be collected from BPA's customers as an annual cost. APAC states that ratepayers should receive a benefit from supplying BPA revenues in advance of the time when they are needed, suggesting that a cash allowance funded by revenues is inappropriate if the only reason for collecting the revenues is to allow BPA to earn interest revenue. APAC argues that BPA ignored the last 3 months of FY 1985 in setting its rates, and thus the rates for the 27-month rate period are already too high. Cook, APAC, E-PA-03, 4. APAC suggests that all ratepayers should not have to be responsible for increases in cash lag adjustments when the increases are clearly identifiable with specific customer groups. Cook, APAC, E-PA-03, 7. APAC states that BPA's calculation of the cash lag overlooks the $27 million already carried over from previous years. In addition, APAC claims that it is not clear that BPA requires a cash lag to make Treasury payments. Initial Brief, APAC, B-PA-01, 18-21. APAC asserts that BPA should allocate all cash lag costs to PSW nonfirm rates. Initial Brief, APAC, B-PA-01, 88-89. Reply Brief, APAC, R-PA-01, 12. APAC also declares that the cash lag adjustment is a "slush fund." Reply Brief, APAC, R-PA-01, 17.

WUTC/OPUC view the cash lag as an allowance for working capital which should be added to rate base and is therefore an improper addition to annual operating expense. In addition, they state that if most of the cash lag is attributed to quarterly billing of one particular customer class, then that class ought to bear the costs of serving them. In conclusion, WUTC/OPUC recommends that BPA eliminate the cash lag adjustment, or if that is not [page 68] feasible, the quarterly billing of PSW nonfirm customers be changed to a monthly schedule. White and Rolseth, WUTC/OPUC, E-OP/WU-01S, 6; Initial Brief, WUTC/OPUC, B-OP/WU-01, 8. WUTC/OPUC reiterates their positions and recommendation in their Reply Brief. Reply Brief, WUTC/OPUC, R-OP/WU-01, 5-7.

**Evaluation of Positions**

APAC's first criticism of the cash lag adjustment, that it should not be collected as an annual cost (Cook, APAC, E-PA-03, 041, reflects a misunderstanding of this component of the Revenue Requirement Study. The cash lag adjustment in the Revenue Requirement Study does not collect the total net cash lag as an annual cost every year. Rather, the cash lag adjustment reflects only the incremental change in the net cash lag from year to year. This change may be positive or negative. When the change is negative, the cash lag adjustment reduces the revenue requirement. The cash lag adjustment is included in BPA's revenue requirement to adjust cash requirements which exist at the end of the fiscal year. These cash requirements exist because BPA is unable to realize them from revenues due to net receivables and prepayments, which occur as a result of higher revenue accruals and Supply System net - billing. This represents a need for working capital. Roberts, BPA, E-BPA-50R, 2. Were it not for the cash lag adjustment, the cash balances would be less than needed to meet projected interest and amortization payments. This operation is detailed in BPA, E-BPA-07A, Chapter 4, Section F, and is discussed in Roberts, BPA, E-BPA-50R, 7.

Second, APAC states that BPA's treatment of the cash lag in the Revenue Requirement Study is inappropriate if the only reason for its inclusion is to allow BPA to earn interest income. Cook, APAC, E-PA-03, 6. This criticism is unfounded. The existence of a cash lag represents a need for working capital. If cash lag were not accounted for in the Revenue Requirement Study, year-end cash balances would be in sufficient to meet BPA's obligations. The cash lag component does not lead to increased interest earning cash balances above the level assumed when calculating the interest credit in the Revenue Requirement Study. Rather, it prevents cash balances from falling below the level assumed when calculating the interest credit in the Revenue Requirement Study. Roberts, BPA, E-BPA-50R, 9.

APAC also alleges that, since BPA ignored the last 3 months of FY 1985 in setting its rates, rates for the 27 month period are already too high. Cook, APAC, E-PA-03, 4. As noted with regard to the scaling process, however, the difference between revenues collected under current and proposed rates has been minimized for the last 3 months of FY 1985. Therefore, the effect on the cash lag is negligible.

APAC asserts, as do OPUC and WUTC, that the cash lag adjustment should be allocated to the customers responsible. Cook, APAC, E-PA-03, 7; Initial Brief, WUTC/OPUC, B-OP/WU-01, 8-9. BPA disburses cash at year end to cover costs related to service for all customers. Relating all cash disbursements to a specific customer class is not a common practice in the utility industry. The cash lag adjustment reflects the incremental difference in [page 69] timing of receipts and disbursements at year end. BPA, E-BPA-07A, Chapter 4, Section F. The isolation of particular end-of-year revenue and expense lags in the calculation is only a proxy for estimating this timing difference. It does not reflect the total effect on cash balances of serving any particular customer class, since the disbursement of cash is an FCRPS requirement and therefore cannot be traced directly to any individual particular customer class. In conclusion, the cash lag adjustment is an obligation necessitated by the fact BPA must make amortization payments. It is not attributable to any specific customer class. APAC states that the language of BPA's power sales contracts with PSW utilities contradicts BPA's position. APAC asserts that these power sales contracts provide for monthly billing only. Initial Brief, APAC, E-PA-01, 88. APAC is mistaken. Section 6 of the power sales contract that APAC refers to was modified by a letter agreement of September 6, 1968, which provides that, in lieu of monthly payments, the utility will be credited in the exchange account. Section 7(b) of the exchange agreement with these utilities provides for quarterly settlement of the exchange account.

Finally, WUTC/OPUC recommends that BPA change the quarterly billing of the PSW customers to a monthly schedule. This is a billing issue rather than a ratemaking issue. BPA, however, will review its billing procedures in the appropriate forum consistent with the comments of WUTC/OPUC.

APAC asserts that BPA's calculation of the cash lag overlooks the cash lag carried over from previous years. Initial Brief, APAC, B-PA-01, 19. This is incorrect. The cash lag calculation incorporates the cash lag from the previous year in its calculation of the cash lag adjustment for any particular year. BPA, E-BPA-07A, Chapter 4, F-17, line 14.

Finally, APAC alleges that it is not clear that BPA needs a cash lag to make Treasury payments. Initial Brief, APAC, B-PA-01, 20. APAC alleges that the cash lag adjustment is a "slush fund" for BPA. Reply Brief, APAC, R-PA-01, 17. This claim ignores that, were it not for the cash lag adjustment, BPA's year-end cash balances could be less than those needed to make projected interest and amortization payments. Roberts, BPA, E-BPA-50R, 11. Since the cash lag adjustment is needed on a planning basis to make scheduled amortization payments, it does not constitute a slush fund.

WUTC/OPUC assumes that the cash lag adjustment serves the same purpose as a cash working capital allowance. White and Rolseth, WUTC/OPUC, E-OP/WU-01S, 6. This is incorrect. A cash working capital allowance is a rate base addition allowed private utilities as compensation for the amount of cash and other assets that a company must maintain to meet the current cost of operation until it is reimbursed by its customers. As noted above, the cash lag for BPA is an addition to the revenue requirement that is used to help ensure that sufficient funds are available at year end to make necessary Treasury payments. Therefore, the cash lag adjustment is treated as an addition to annual obligations and not as a working capital allowance which would be added to rate base.

[page 70]

**Decision**

*The cash lag adjustment is properly designed in that it does not double count the effects of the cash lag from year to year, but simply adjusts for the incremental change in the net cash lag from year to year by taking into account previous years' cash lags. This is an appropriate means of ensuring that sufficient funds are on hand at year end in order to make BPA's required payments to the Treasury. In addition, BPA's Revenue Requirement Study properly accounts for the interest earnings on the cash lag adjustment. The cash lag adjustment does not reflect the total effect on cash balances of any particular customer class, since the disbursement of cash is an overall FCRPS requirement. The cash lag adjustment should not be construed as a cash working capital allowance; rather, the adjustment converts the revenue requirement from an accrual to a cash basis. BPA, however, will review its billing procedures in order to move towards monthly billing of PSW nonfirm energy customers.*

### E. Issues Related to the Separate Accounting Compliance Filing

**Issue #1**

*Should proposed 1985 rates recover the underrecovery of revenues associated with non-Federal use of the FCRTS?*

**Summary of Positions**

WPAG argues that the Commission intended that BPA include a surcharge in proposed 1985 rates to recover the $30 million disproportionate underrecovery reported in BPA's Compliance Report of May 29, 1984, in Docket No. EF84-2021-000. Hutchison, et al., WPAG, E-WA-01, 55-57. PNGC argues that BPA should attempt to link any surcharge to customer usage during the time the underrecovery was incurred. PNGC states that the wheeling customers that caused the underrecovery should bear the burden of any surcharge. Johnson, PNGC, E-PN-01R, 7-8.

In contrast, PSP&L argues that no underrecovery has been shown to exist. PSP&L, Puget, B-PS-01, 11.

**Evaluation of Positions**

WPAG and PNGC misconstrue the purpose of the Compliance Report and have taken the $30 million figure out of context. The method on page 15 of that report did indeed show a disproportionate $30 million underrecovery. However, BPA did not advocate the imposition of any surcharge and does not propose to do so absent a Commission order.

During its review of BPA's final rate proposal for 1983, the Commission decided to withhold approval of proposed wheeling rates until BPA developed [page 71] separate books of account that tracked surpluses and deficits associated with Federal and non-Federal usage of the FCRTS. In the Compliance Report that followed, BPA developed the income statement approach shown in Attachment 5 of that report. It was BPA’s intention to develop a "tracking system" to assist the Commission in determining whether FRCTS costs were being allocated properly, on a prospective basis, between Federal and wheeling usages.

Generally, the income statement analysis demonstrated that there had been no disproportionate over- or underrecoveries of revenue from Federal and non-Federal users of the transmission system. The only exception related to FY 1981 during which a combination of contractual limitations and regulatory lag prevented BPA from increasing wheeling rates when it increased power rates. Compliance Report, 12-15. A wheeling revenue underrecovery of $30 million was associated with this nonrecurring event, which was independent of the way in which BPA had allocated costs between the two users of the FCRTS.

BPA did not recommend the imposition of any surcharge to recover this $30 million. Instead, the agency stated it would maintain the separate accounting system in all future rate cases, monitoring the $30 million underrecovery figure to determine whether it increased or abated over time. It was, and is, BPA's belief that the underrecovery would not be exacerbated, because its cause was nonrecurring.

Given this analysis, BPA does not consider a surcharge to be appropriate. BPA stated in the Compliance Report that "[t]here is nothing in the relevant statutes or in the Commission’s orders on separate accounting that expressly would require BPA to redistribute past imbalances such as the $30 million described above…" Further, BPA told the Commission:

> …if the Commission determines that any surcharge is legally required, BPA would not propose to assign prior year underrecoveries simply by mechanical application of the historical analysis provided in this report. To determine the time period over which any underrecovery should be recovered, BPA must consider contemporary facts such as the price sensitivity of wheeling service, BPA's competitive situation and inter-generational equity issues. Moreover, the FY 1984 income statement will become available before BPA concludes the 1985 rate case. It may well be the case that a wheeling revenue surplus in FY 1984 would mitigate the prior underrecovery to the point where there was no material inequity remaining. [Compliance Report at 17-18.]

The BPA Compliance Report was prepared and submitted to the Commission within 4 months after the Commission so ordered. Nearly 1 year has passed since that report was filed. In the meantime, the Commission received comments from those BPA customers who wished to address the separate accounting issue. To date, the Commission has not addressed the separate accounting issue, although BPA requested expeditious consideration to aid BPA in the development of proposed rates for 1985.

[page 72]

**Decision**

*BPA reiterates its commitment to provide the Commission with a separate accounting of Federal and non-Federal usages of the FCRTS. Such information will be included with the final 1985 rate proposal. However, the Administrator has not changed his decision not to impose a surcharge to recover a short-lived, nonrecurring underrecovery from wheeling customers-absent a clear order from the Commission to do so. The Compliance Report did not conclude that an inequitable underrecovery occurred. That determination rests with the Commission in its review of the 1983 rates.*

### F. Exchange Cost Projections

**Issue #1**

*Should BPA modify public agency Average System Cost (ASC) projections so that these ASCs are held constant over the rate period?*

**Summary of Positions**

BPA escalates components of each public agency's ASC by assuming that each public agency's ASC will change every October. Therefore, ASC components increase during each month over the rate period. BPA, E-BPA-18, Attachment 1, 14.

WPAG argues it is unlikely that public agency exchange customers will change their residential rates after July 1, 1985, until BPA readjusts its wholesale rates in October 1987. Hutchison, et al., WPAG, E-WA-01, 58. WPAG suggests that BPA should estimate ASC as of

July 1, 1985, and use this ASC for the entire 27-month rate period for exchanging public agencies. Hutchison, et al., WPAG, E-WA-01, 58-59.

**Evaluation of Positions**

It is true that some public agency customers set rates using the same rate period as BPA. However, this does not mean that their costs are constant during the entire period. BPA assumes that rates will increase from July 1, 1985, through October 1, 1987. Even for utilities that use the 27-month period to set rates, these rates will project costs adjusted for inflation. If BPA forecasted FY 1986 or FY 1987 exchange costs using FY 1985 prices, the estimate would be too low. Consequently, BPA rates would not be sufficient to meet its revenue requirement in FY 1986 or FY 1987.

**Decision**

*BPA's method of projecting public agency ASC's is reasonable. The change in the method of projecting public agency ASC's proposed by WPAG does not differ substantially from BPA's approach, assuming that such public agencies*
[page 73] *will normalize their costs when establishing an ASC for the 27-month rate period. Using FY 1985 price levels to forecast FY 1986 and FY 1987 costs would underestimate public agency exchange costs for the rate period. Moreover, any potential overstatement of exchange costs will be mitigated by operation of the exchange adjustment clause.*

**Issue #2**

*Should BPA's projection of public agency exchange costs be lowered to take into account the revenue requirement cap contained in the ASC methodology?*

**Summary of Positions**

The revenue requirement cap is explained on page 55 of the Administrator's Record of Decision for the 1984 ASC Methodology as follows:

> …if depreciation expense is not included in retail ratemaking for the exchanging utility, then return will be equal to the lesser of (1) interest expense plus depreciation expense; or (2) debt service plus revenue-financed capital expenditures. In no event will the sum of Contract System Cost and Distribution/Other costs be greater than the revenue requirement used to set rates.

The revenue requirement cap ensures that no exchanging utility can calculate its ASC based on a Contract System Cost that exceeds the amount recovered from rates. BPA did not include the revenue requirement cap when forecasting public agency exchange costs since sufficient information was not available to determine which utilities would be affected by the cap. WPAG claims that BPA's not including the revenue requirement cap limits exchange subsidies paid to public agencies. Hutchison, et al., WPAG, E-WA-01, 59.

**Evaluation of Positions and Decision**

The utility's revenue requirement is controlled by the filing utility. The record contains in sufficient data to allow BPA to predict which utilities, if any, would be affected by the revenue requirement cap. BPA does know, however, that the return component included in Contract System Cost cannot exceed rate-of-return times rate base. To ensure that BPA's rates will recover sufficient revenues, the revenue requirement cap is not included in the forecast of public agency exchange costs.

[page 74]

## G. Fish and Wildlife Program Levels

**Issue #1**

*Is the correct amount of capital borrowing for fish and wildlife included in the Revenue Requirement Study?*

**Summary of Positions**

The program level for fish and wildlife in the Revenue Requirement Study includes $14.7 million in capital borrowing for FY 1986. BPA, E-BPA-07, 51. The program level for fish and wildlife in FY 1987 includes $12 million in capital borrowing. BPA, E-BPA-07, 54. PPC asserts that these capital borrowing levels should be reduced by $950,000 in FY 1986 and $3.95 million in FY 1987. Brawley, PPC, E-PP-02, 4. PPC argues that these amounts represent a "contingency fund" for measures added to the Columbia River Fish and Wildlife Program by amendment, and that there are no specific projects identified for these funds. PPC states that capital projects require extensive studies, planning, analysis of environmental impacts, and design prior to expenditure, and that it is unlikely that unidentified capital projects will be approved and implemented. Brawley, PPC, E-PP-02, 4-5.

**Evaluation of Positions**

The program levels for fish and wildlife contained in the Revenue Requirement Study are for expenditures in discharging BPA's responsibility to protect, mitigate, and enhance fish and wildlife affected by the development and operation of hydroelectric facilities in the Columbia River Basin. Palensky, BPA, E-BPA-15, 1. For the most part, such expenditures carry out measures contained in the Northwest Power Planning Council's Columbia River Basin Fish and Wildlife Program. Palensky, BPA, E-BPA-15, 2. The program levels for fish and wildlife contained in the Revenue Requirement Study include funds for measures expected to be added to the Fish and Wildlife Program by amendment. Palensky, BPA, E-BPA-15, 2.

PPC is incorrect in asserting that the full amount of capital borrowing included in the program level for fish and wildlife cannot be obligated during the rate case period. The original program level estimates for the Revenue Requirement Study included no funds for new capital expenditures for projects added to the Program by amendment, but included $2.5 million for such projects in FY 1987. At the time these estimates were made, no projects were identified for the $2.5 million in capital borrowing for FY 1987. Palensky, BPA, E-BPA-49R, 2. However, the Northwest Power Planning Council subsequently amended the Fish and Wildlife Program.

On the basis of these amendments, BPA has considered six projects for capital borrowing in FY 1986 and FY 1987. Predesign work for these projects is either completed or underway. Palensky, BPA, E-BPA-49R, 3. BPA expects to fund in both FY 1986 and FY 1987 capital projects added to the Program by those amendments. Palensky, BPA, E-BPA-49, 2-3. In combination with capital projects already in the program [page 75] and planned for funding in FY 1986 and FY 1987, the projects called for by the program amendments will require the full amount of capital borrowing included in the Revenue Requirement Study. Palensky, BPA, E-BPA-49R, 4. PPC has failed to establish that these levels cannot be obligated and are not needed.

**Decision**

*The program levels for fish and wildlife in the Revenue Requirement Study correctly include $14.7 million for capital borrowing in FY 1986 and $12 million for capital borrowing in FY 1987. The full level of capital borrowing included in the Revenue Requirement Study will be needed in both FY 1986 and 1987.*

**Issue #2**

*Is the BPA rate filing the proper forum for discussion of the capital project budget of the Fish and Wildlife Program?*

**Summary of Positions**

PPC argues that the rate filing is the proper forum for "discussion of the capital project budget." They argue that no other adequate and effective opportunity is available to address the actual dollar amounts for capital projects, and that "BPA's decision making process, whereby it decides on which of the Council recommended programs should be implemented, is too indefinite a process to allow for meaningful involvement." Initial Brief, PPC, B-PP-01, a 50-51. BPA maintains that only the actual dollar amounts included in the revenue requirement for capital projects are addressed in the rate proceeding.

**Evaluation of Positions**

PPC's arguments rest on the charge that there is no other forum in which to address decisions to fund specific projects. Initial Brief, PPC, B-PP-01, 50-51. These arguments ignore the fact that BPA annually provides advance notice to BPA customers of major capital improvements to be submitted for congressional approval, affording interested parties an opportunity to participate in congressional deliberations. In addition, BPA annually conducts a process to review and develop detailed project funding plans for the current fiscal year. This process includes distribution of lists of proposed projects with opportunity for parties to comment and to participate in meetings to discuss project funding.

BPA began a public review process for the 1987 fish and wildlife budget plans at the earliest stage of BPA’s budget development procedure. This process allows interested parties to review and comment on budget plans for major capital improvements as well as the other aspects of BPA’s fish and wildlife budget.

BPA has consistently maintained that decisions to fund specific projects are not at issue in the rate filing. The Record of Decision in BPA’s 1983
[page 76] rate filing states, "The purpose of BPA testimony concerning fish and wildlife program levels is to substantiate the revenue requirement in the rate case, not to justify BPA’s fish and wildlife responsibilities… To provide such programmatic justification would necessitate going far beyond the scope of the ratemaking process."

The actual dollars included in BPA's revenue requirement are always subject to discussion in the rate filings. This is no different for capital expenditures included in the projected revenue requirement. However, the purpose of the procedures established under section 7(i) of the Northwest Power Act is to examine on the record whether BPA’s rates satisfy section 7(a)(1) of the Act, not to justify every program that contributes to BPA's costs. 16 U.S.C. §§839e (i), 839e (a)(1). For this reason decisions to undertake programs that feed into the revenue requirement are made in other forums, and those decisions are not at issue in the rate proceedings.

**Decision**

*Actual dollars included in BPA's revenue requirement remain proper subjects of testimony and cross examination in the rate filing. BPA is not required to address program decisions in the rate filing. BPA continues to encourage active public involvement in the process of evaluating major program decisions. BPA is expanding the opportunity for such participation in the fish and wildlife budget process.*

[page 77]

## IV. MARGINAL COST ANALYSIS

### A. Introduction

The Marginal Cost Analysis (MCA) is a cost of service study depicting the incremental costs BPA would incur on a seasonal, daily, and hourly basis for new generation and transmission load. The analysis identifies the projected costs to be incurred to meet increased customer demand or those costs avoided by a decrease in customer demand. This analysis differs from an embedded cost of service analysis that reflects the book cost BPA is required to recover based on accounting and repayment practices.

BPA’s MCA applies the principles of marginal cost pricing to electric rates, given the constraints under which BPA must operate. The process involves an analysis of additional facilities needed to meet additional demands for power. The Least Cost Mix Model (LCMM) provides a basis for defining the type of incremental generation facilities to be included in the MCA. The System Analysis Model (SAM) analyzes how the incremental generation facilities would be operated in conjunction with the existing system to meet incremental load. The planning horizon used in the analysis allows for the development of marginal costs that reflect an optimal mix of generation and transmission capacity over power surplus as well as deficit periods.

The information developed in the MCA is used throughout the development of BPA's wholesale power rates. For the Cost of Service Analysis (COSA), the MCA provides the basis for the classification of generation costs between capacity and energy, and for the seasonal differentiation of capacity costs. The Wholesale Power Rate Design Study (WPRDS) uses the results of the MCA to classify revenue adjustments between capacity and energy and to time differentiate the capacity rates on a daily and hourly basis. The WPRDS also uses the MCA in the development of the unauthorized increase charge and the Priority Firm Power and Reserve Power rates. By using the MCA, the rates developed to recover BPA's revenue requirement consider BPA's costs for producing incremental (marginal) amounts of energy and capacity.

**B. Theoretical Considerations**

**Issue #1**

*Is it appropriate to employ the results of the MCA in setting rates?*

**Summary of Positions**

BPA uses the results of the MCA several places in the ratesetting process. Rates that reflect marginal cost principles incorporate the goal of
[page 78] economic efficiency into the price of electricity. Scarcity of resources dictates that choices be made among goods and services; these choices should be based on the relative marginal costs of producing the various goods and services. BPA, E-BPA-02, 2-3; Emery, BPA, E-BPA-22, 13-19.

APAC argues that BPA's rate design objectives are inconsistent with the theoretical requirements for marginal cost-based rates. APAC claims that the use of marginal cost-based rates in the absence of these theoretical requirements produces results that may not promote efficiency. Shanker, APAC, E-PA-04, 4, 6-9, 13-16. APAC argues that price signals cannot be achieved because the MCA results are used for purposes other than for setting prices. APAC states that BPA has acknowledged that its customers do not respond to price. Shanker, APAC, E-PA-04, 4, 9-10, 11-13. In addition, APAC asserts that the levelizing of short-run and long-run marginal costs in the MCA is inappropriate. Shanker, APAC, E-PA-04, 4, 10-11; Pre-Hearing Brief, APAC, P-PA-01, 8-9; Initial Brief, APAC, B-PA-01, 75-77.

SCE maintains that welfare economic theory does not justify the assertion that the use of the relationship between marginal capacity and energy costs improves allocative efficiency when full marginal cost-based rates cannot be charged. Waddell, SCE, E-CE-02A, III-1.

PGP also disagrees with BPA's general philosophy that a marginal cost analysis is appropriate to determine wholesale capacity/energy cost relationships. Knitter, PGP, E-PG-06, 1; Pre-Hearing Brief, PGP, P-PG-01, 10; Initial Brief, PGP, B-PG-01, 16.

WPAG indicates that a marginal cost analysis can provide useful information concerning how a utility's costs change over time. WPAG agrees with BPA that the use of the MCA provides price signals that encourage customers to make prudent capital investment decisions. Hutchison, et al., WPAG, E-WA-01, 31; Pre-Hearing Brief, WPAG, P-WA-01, 10-11; Initial Brief, WPAG, B-WA-01, 19; Reply Brief, WPAG, R-WA-01, 23.

OPUC approves of the use of marginal costs in the ratesetting process because their use provides fair and reasonable cost allocations and encourages efficiency in the production and use of electricity. White, OPUC, E-OP-01, 5-6.

PP&L and PGE support BPA's position that rates based on marginal costs send a more appropriate price signal to the consumer than do rates which do not take into account marginal cost. Initial Brief, PP&L and PGE, B-GElPL-01, 1.

NIU agrees that long run marginal costs are appropriate references for setting power rates because they promote economic efficiency. Initial Brief, NIU, B-NI-WS-NE-01, 5.

**Evaluation of Positions**

BPA acknowledges the strict theoretical conditions necessary for pure marginal cost pricing. Emery, BPA, E-BPA-22, 15-16. APAC notes that its [page 79] testimony filed in the 1982 and 1983 Wholesale Rate Proceedings addressed the problems associated with the theoretical specification and application of marginal cost pricing. Shanker, APAC, E-PA-04, 6-7. BPA addressed these concerns in the Record of Decision for each of those proceedings. 1983 Rates ROD, 108-112, 118-122; 1982 Rates ROD, 46-47. Since the arguments and evaluations are the same for all three proceedings, they will not be reiterated here.

The arguments made by APAC, SCE, and PGP rely on pure theory and ignore the realities faced by BPA. For a variety of reasons, BPA does not employ full marginal cost-based rates. To do so would imply that economic efficiency is the sole objective addressed by BPA's rates, and would disregard the fact that BPA must also consider other objectives in conjunction with economic efficiency. Emery, BPA, E-BPA-22, 13-14. The simple assertion that economic efficiency and BPA's other ratemaking objectives are inconsistent and that the ratemaking procedure employed by BPA does not follow strict economic theory is not persuasive. The strict theoretical and mathematical constructs of economic theory will rarely fit society on a practical level. The underlying logic of economic theory and the resulting general observations, however, can be useful. For example, the price of a product is important to potential purchasers of the product. This concept is from economic theory; it was not disputed in this case since its logic is clear. BPA does not attempt to develop rates given only strict economic theory. The intent is to develop rates that meet a variety of objectives. APAC argues only that BPA's objectives "may" be mutually exclusive (Shanker, APAC, E-PA-04, 7) and that "we have no idea whatsoever whether any single pricing action will improve economic efficiency or not" (emphasis in original). Shanker, APAC, E-PA-04, 14. However, APAC has not demonstrated that BPA's objectives are mutually exclusive or inconsistent or that their application will reduce economic efficiency. BPA's position, based on the applicability of the general constructs and relationships of welfare economics, is that economic efficiency is a valid objective: in addition, the resulting rates, though deviating from strict marginal cost-based rate principles to meet other objectives, still provide clear and meaningful information to BPA's customers about BPA's marginal cost of producing electricity. This position is supported by WPAG, OPUC, PP&L, PGE, and NIU.

Another APAC argument concerns the roles of price signals at the wholesale and retail levels. APAC asserts that BPA has acknowledged that the purported price signals contained in BPA's rates are not being relayed to customers at the retail level. Shanker, APAC, E-PA-04, 12-13. BPA sells wholesale power. Therefore BPA must set prices with regard to customer response at the wholesale level. BPA expects that individual customer utilities will respond to BPA's rates in manners appropriate to their situations. The important fact is that the wholesale utilities, since they are the purchasers of BPA's power, are provided an indication of BPA's cost characteristics. This will allow the utilities to make informed decisions concerning their own operations and to meet their objectives in setting retail rates.

APAC also claims that BPA has inappropriately levelized long run and short run marginal costs. Shanker, APAC, E-PA-04, 4, 10-11; Pre-Hearing Brief, [page 80] APAC, P-PA-01, 8-9; Opening Brief, APAC, B-PA-01, 75-77. The ICP supports the levelizing of cost by defining marginal cost as the change in the present value of system costs resulting from some decision, i.e., the decision to produce more electricity. Weitzel and Sirvaitis, ICP, E-IC-03, 2. The present value process -- the levelizing of cost -- is important for an accurate specification of marginal cost. A change in load during the test year affects resource planning over the entire planning horizon. The levelizing of the cost in real terms over the planning horizon determines an annual marginal cost to meet the changed load. Linear programming (LP) models such as the LCMM use this levelizing approach. LP models are maintained and used by PGE, OPUC, the Northwest Power Planning Council, and the DSIs (through their consultants) to estimate least-cost resource mixes and marginal costs. Fuqua, BPA, E-BPA-14, 20.

Finally, APAC discusses the opinion rendered by the District of Columbia Circuit Court of Appeals (*Electric Consumers Resource Council v. Fed. Energy Regulatory Comm'n*, 747 F.2d 1511 (D.C. Cir. 1984)) (hereafter *Elcon*). Initial Brief, APAC, B-PA-01, 73-75; Reply Brief, APAC, R-PA-01, 28. Marginal costing is the subject of *Elcon*. At the commission level, the Federal Energy Regulatory Commission adopted a rate design which was a modifies form of marginal pricing (*Wisconsin Elec. Power Co.*, 24 FERC ¶61,299 (1983) [hereafter *WEPCO*].) The *Elcon* court reversed that adoption, but not on the grounds that marginal costing is an unacceptable rate design device (747 F.2d at 1517, 1518). The underlying reason for the reversal was the Commission's failure to develop substantial evidence in the record to support use of the method (747 F.2d at 1513, 1518).

> An agency's view of what is in the public interest may change, either with or without a change in circumstance. But an agency changing its course must supply a *reasoned analysis* … and if an agency glosses over or swerves from prior precedents without discussion it may cross the line from the tolerably terse to the intolerably mute. 747 F.2d at 1517 (emphasis in original; quoting from *City of Charlottesville v. Fed. Energy Regulatory Comm'n*, 661 F.2d at 945 (D.C. Cir. 1981)).

> In sum, we unequivocally state that we are not hereby expressing our opposition to the adoption of marginal cost based rate designs in *any* form. We are concerned only with the total lack of record support for FERC's position and with the lack of reasoned decision-making on the part of FERC. 747 F.2d at 1518 (emphasis in original).

APAC's contention (Initial Brief, APAC, B-PA-01, 73) that the formulation of WEPCO's marginal cost-based wholesale rates was almost identical to BPA's approach is incorrect. WEPCO based its proposed energy rates solely on its estimated marginal cost of energy, then arbitrarily reduced the marginally priced demand rates to an amount sufficient to recover the difference between its revenue requirement and the revenue to be received from the sale of [page 81] energy. 747 F.2d at 1513. BPA instead determines the marginal cost of generation capacity and energy and uses this relationship to classify embedded generation costs. These two approaches are not similar. BPA's rate design does not price either capacity or energy components at their marginal cost (*see* Initial Brief, APAC, B-PA-01, 73).

BPA did not rely on *WEPCO* "solely … as support for its testimony" as APAC claims (Reply Brief, APAC, R-PA-01, 28, n. 26); the witness cited *WEPCO* in rebuttal testimony (Emery, BPA, E-BPA-62R, 2-3) for a summarization of the arguments favoring marginal costing theory. *Elcon* does not discuss the merits of the theory, but it does explain why the Commission erred. Evidence in the record showed that the Commission's modified version tracked actual costs less accurately than did average pricing (747 F.2d at 1514), and that the modified version was unjustly discriminatory because it resulted in different charges for similar services to similar customers (747 F.2d at 1515). Moreover, the Commission, in the past having adhered to average pricing, switched to marginal pricing without a factual analysis (747 F.2d at 1517).

The application of marginal cost principles to rate development by BPA is not a new procedure. BPA has incorporated marginal cost principles in its rate design since 1979. Emery, BPA, TR 2947; Initial Brief, APAC, B-PA-01, 72. BPA is not now switching, as did the Federal Energy Regulatory Commission, to a new approach that is unbuttressed by a factual analysis of its impacts. BPA has analyzed the effects of its current overall classification of costs on loads and revenues (*see* Generic Classification Issues, Chapter 11, Section E l. These analyses show that BPA has no reason to change its current MCA based cost classification methodologies.

**Decision**

*The results of the MCA are used in the development of BPA's rates. The use of the MCA promotes economic efficiency, a desirable goal for ratesetting. Parties opposing the use of marginal cost principles did not show that their use creates undesirable results. Parties arguing that BPA modify its historical procedure for applying marginal cost principles to rate design did not provide an analysis of the impact of their proposal sufficient to justify the change in procedure. The use of marginal cost principles, an established procedure in setting BPA's rates, provides theoretically correct price signals to BPA's customers to encorage [sic] the economically efficient consumption of electricity.*

## C. Marginal Cost of Generation

## **Issue #1**

*Is it appropriate to use the combined operation of SAM and the LCMM in determining the marginal cost of generation?*

[page 82]

## **Summary of Positions**

In the MCA, the total marginal cost of generation is estimated by use of the LCMM and SAM. The LCMM is a linear programming computer model. It is designed to estimate the mix of regional generation and conservation resources that will minimize the total cost to the region: (1) under conditions of critical water considering projected firm power surplus or deficit; (2) given an inventory of potential new resources; and (3) given the value of additional surplus firm power that may be produced by resource acquisitions. SAM simulates the economic operation of the region's hydrothermal generating system under expected water conditions. The major inputs to SAM are forecasted load, projected resources from the LCMM, and operational assumptions based on regional policy. The simulation determines the use and operation of hydrothermal generating resources to meet firm and nonfirm regional loads, as well as sales to potential markets outside the region. The cost analysis develops a total system cost for a proposed resource expansion. BPA, E-BPA-02, 5-11; Emery, BPA, E-BPA-22, 5; Pre-Hearing Brief, BPA, P-BPA-01, 12-1 3.

APAC maintains that a mismatch exists between the specific objectives of the two models. Shanker, APAC, E-PA-04, 4. The LCMM seeks the minimization of the present value of all capital and operating costs, while SAM is a normative model that simply duplicates the historic behavior of operators. APAC claims that the combined operation of the models thus does not measure the optimal economic operation of the system. Shanker, APAC, E-PA-04, 16-19; Initial Brief, APAC, B-PA-01, 77. In addition, APAC claims that this mismatch is exacerbated by the fact that the LCMM operates on the basis of critical water, while the SAM operates under conditions of average water. Shanker, APAC, E-PA-04, 4, 19-22; Initial Brief, APAC, 0-PA-01, 77. Finally, APAC argues that the use of the combined results from the LCMM and SAM leads to unrealistic results in that the plant factors in the LCMM are preset, and the data and parameters in the normative SAM model are more arbitrary than objective. Shanker, APAC, E-PA-04, 5, 27-29.

The ICP and PP&L and PGE advocate that the MCA should base the marginal cost estimates on results from only the new LCMM. Weitzel and Sirvaitis, ICP, E-IC-03, 1; Pre-Hearing Brief, ICP, P-IC-01, 4; Initial Brief, PP&L and PGE, B-GE/PL-02, 2; Reply Brief, PP&L and PGE, R-GE/PL-01, 1. They argue that the SAM model cannot consider investment decisions. These parties conclude that SAM is not useful in determining the cost-minimizing demand/energy trade-offs for the region. Weitzel and Sirvaitis, ICP, E-IC-03, 10.

## **Evaluation of Positions**

The MCA measures the cost associated with a change in resource planning and operation as a result of a change in load. Currently, the LCMM and the SAM are both used in BPA's resource planning and budgeting process. Fuqua, BPA, E-BPA-14, 21-22. Consistent with BPA's planning criteria, the LCMM determines the least-cost set of resources to meet incremental load under critical water conditions. SAM simulates the operation of existing resources [page 83] and new resources from the LCMM to meet forecasted load, and minimizes total cost while recognizing regional reliability and operating constraints. Fuqua, BPA, E-BPA-14, 24. These models are not incompatible. To determine the least-cost, long-run resource optimum mix requires identification of the least-cost set of incremental resources, and consideration of how those resources would be operated in conjunction with the existing system to meet forecasted load. Regional operation and reliability constraints must be considered. Emery, BPA, E-BPA-62R, 5. The APAC argument does not consider the fact that operation of a hydro system is considerably more complex and subjective than the operation of a thermal system. The operation of resources in a thermal system can be modeled almost exclusively on the basis of objective criteria, such as cost. Modeling the more complex operation of a hydro system requires subjective decision rules, such as an operators perception of the risk of not meeting rule curves. Shanker, APAC, E-PA-04, 18. In addition, the cost of meeting load on a hydro system varies with the water conditions in any given year, whereas the cost of meeting load on a thermal system varies primarily with fuel cost. Thus, an appropriate measure of the long-run cost of meeting load growth on a hydro system must consider expected water conditions over the planning horizon. Simply because incremental resources are selected on a critical water basis, and system operation costs are developed on an expected water basis, does not invalidate the MCA results. The MCA results are realistic in that they consider the actual planning and operational conditions faced by BPA. Emery, BPA, E-BPA-62R, 5-6.

The APAC position concerning preset plant factors in the LCMM is also unpersuasive. The LCMM selects the least cost resources available. The cost of each resource type is developed assuming that the resource is being operated at its most efficient level of output under critical water conditions. Preset plant factors are therefore appropriate. The operation of these resources under expected water conditions is optimized in SAM. SAM modifies the operation of these resources so that under expected water conditions thermal resource operation can be displaced with less expensive nonfirm energy. Under current regional planning criteria, however, none of the operations in SAM would result in a different least-cost mix of resources. The LCMM will optimize the mix of resource additions under regional planning criteria, while SAM optimizes the operation of the entire system, including future resources, under expected conditions. Emery, BPA, E-BPA-62R, 6.

The ICP argument that only the new LCMM be used rests on the inability of SAM to consider investment decisions. The LCMM models the investment decisions; SAM simulates both operational planning functions and actual operations. Fuqua, BPA, E-BPA-14, 24. The combined operation of the two models is required to develop a minimum cost scenario. The development of the new LCMM recognizes this relationship and includes the ability to assess factors that are also considered through the operation of SAM, such as varying water conditions. To keep the model manageable, however, many of the features incorporated in the new LCMM were simplifications or approximations of SAM. Fuqua, BPA, E-BPA-14, 22-23.
[page 84]

**Decision**

*The new LCMM is used in the final MCA in lieu of the LCMM model used in the initial proposal. The combined operation of the LCMM and the SAM develops marginal costs based on the* *operating and planning realities faced by BPA. The new LCMM cannot be used alone in estimating marginal cost. The new LCMM contains highly simplified representations of system operations based on SAM; therefore, the information derived from the SAM itself provides the best estimate of optimal system operation available. The new LCMM contains up-to-date resource cost and availability information, and has already been used in the 1985 rate filing for the WNP-1 and -3 analysis. Fuqua, BPA, E-BPA-14, 23. The new LCMM is operated in conjunction with the SAM for the final MCA in a manner consistent with the use of the LCMM in the initial proposal.*

**Issue #2**

*Is the planning horizon used in the MCA for calculating total marginal generation cost appropriate?*

**Summary of Positions**

The MCA uses the results of the LCMM and SAM in determining the total marginal cost of generation. Both of these models operate over a 20-year planning and operation horizon. Currently, the models are operating over the period 1985 through 2004. The MCA uses LCMM and SAM information during the 18-year planning horizon of 1987 through 2004. BPA, E-BPA-02, 6-9, 28-29.

The DSIs argue that the use of an 18-year planning horizon is speculative as well as inconsistent with BPA's actual resource plans. The DSIs claim that information based on a shorter planning horizon would be more precise. For example, BPA's Draft Resource Planning Strategy Document commits to resource plans for only a 4-year period. The DSIs recommend that BPA use a 7-year planning horizon to be consistent with actual resource construction lead times and with BPA's value of reserves analysis. Carter, DSI, E-DS-07, 1-4; Initial Brief, DSI, B-DS-01, 126-127.

PGP supports the DSI position. Knitter, PGP, E-PG-06, 2; Pre-Hearing Brief, PGP, P-PG-01, 10; Initial Brief, PGP, B-PG-01, 16-17.

NIU believes that BPA should forecast no further into the future than necessary to support decision making, in order to minimize forecasting errors. The NIU supports a planning horizon of 7 years, consistent with the value of reserves analysis; that period would reflect the actual lead time required to construct additional generation. Gates, NIU, E-NI-03, 15; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 8-9; Initial Brief, NIU, B-NI-WS-NE-01, 6-7.

[page 85]

**Evaluation of Positions**

The MCA analyzes costs over the long run, a period of time that allows for changes in plant capacity. Long-run marginal cost is the change in cost due to a change in output that occurs over a time period where capacity can be varied. The short-run period is the time over which some inputs to the production process are fixed. Short-run marginal cost is thus the change in cost due to a change in production during a time period too short to add or reduce plant capacity. Emery, BPA, E-BPA-22, 2.

The arguments made by the DSIs and NIU focus in part on the definition of the long run. The resources selected by the LCMM to meet incremental load have relatively short construction lead times. Emery, BPA, TR 2866-69, 2887-88; Initial Brief, DSI, B-DS-01, 126-27. A planning horizon considerably shorter than 18 years could be used and still fulfill the requirements for a long run study.

The DSI/NIU argument, while true in theory, does not consider the difficulties associated with resource planning. Resource planning decisions are complex and should consider as much information, whether uncertain or not, as possible. As noted by ICP and PP&L and PGE, the best way to deal with uncertainty is not to ignore it. Weitzel and Sirvaitis, ICP, E-IC-15R, 2; Initial Brief, PP&L and PGE, B-GE/PL-01, 7-8.

NIU argues that a forecast should be made for the shortest possible period necessary to support decisionmaking. Gates, NIU, E-NI-03, 15. The resource planning document noted by the DSIs (Carter, DSI, E-DS-07, 3) is BPA's resource acquisition strategy. The decisions contained in this document are based on a 20-year analysis. However, due to uncertainties inherent in a 20-year analysis, the document commits to a strategy for only a 4-year period. Emery, BPA, E-BPA-62R, 7. WPAG agrees that the longer planning horizon should be used since the MCA should consider a period of time that extends beyond periods of resource surpluses or load underruns to provide for a relatively stable analysis over the long term. Hutchison, et al., WPAG, E-MA-02R, 18-20; Reply Brief, WPAG, R-WA-01, 25.

The DSIs and NIU also argue that a 7-year planning horizon should be used in the MCA to be consistent with the 7-year horizon used to determine required plant delay reserves. The 7-year provision is a contractual matter, however, intended to provide BPA with some certainty concerning its future obligations. Peters, BPA, E-BPA-33, 33; Carter, DSI, E-DS-07, 3-4. This contractual specification does not indicate that expected load growth beyond 7 years, while less certain, will not influence BPA's resource planning process.

The DSIs make an additional argument that the planning horizon used in the MCA should be different from the one used for resource planning decisions. The argument is that the use of the MCA results in developing rates requires use of the more certain, shorter, planning horizon. Initial Brief, DSI, B-DS-01,'126. This position ignores the fact that the primary emphasis of the [page 86] MCA is to measure how system plans react to a change in load. BPA, E-BPA-02, 5-6; Emery, BPA, E-BPA-22, 2. To measure the cost associated with a change in plans over only a portion of the actual planning horizon would understate the total effect of the load change.

**Decision**

*The MCA is based on the planning horizon used in BPA's resource planning models. As much information as is available should be considered in the development of resource planning strategies. Since the MCA measures the change in cost associated with a change in load, the total effect of load changes on the resource planning process should be considered. Selecting some subset of the planning horizon would be no more accurate in that it would neglect useful information.*

**Issue #3**

*Does BPA use an appropriate increment in load in determining the marginal cost of generation?*

**Summary of Positions**

To estimate the change in costs associated with a change in load, the MCA develops costs associated with a base load forecast. It then increases the load in 1987 through 2004 by 1,000 average annual megawatts and develops a new set of costs. Since the LCMM and SAM are essentially energy models, the load increase in the initial MCA was for energy only (no peakload increase). BPA, E-BPA-02, 28; Emery, BPA, E-BPA-22, 10.

WPAG suggests that the 1,000 average megawatt increase was selected only due to its ease of calculation. WPAG argues that the load change should be based on the difference between the medium and high load forecasts for each year from 1987 through 2004. This difference is based on BPA load forecasts and can be considered a load with a reasonable probability of occurring. Hutchison, et al., WPAG, E-WA-01, 36-37; Pre-Hearing Brief, WPAG, P-WA-01, 12-13.

APAC argues that the use of the 1,000 average megawatt increment is inconsistent with the approach used in previous marginal cost studies and does not reflect expected loads on the system. APAC also maintains that the effect of the load increment on SAM and LCMM assumptions and limitations was not considered in determining the size of the increment. Shanker, APAC, E-PA-04, 25-27.

PGP agrees with WPAG that the 1,000 average megawatt load increment was arbitrarily selected. PGP also argues that the increment is inappropriate since it included no assumption concerning incremental peakload. PGP claims that a system load factor should be applied to the incremental energy load to determine the associated peak load increment, and the MCA should then use both
[page 87] the peak and energy increments in determining marginal costs. Knitter, PGP, E-PG-06, 2-3; Pre-Hearing Brief, PGP, P-PG-01, 10-11; Initial Brief, PGP, B-PG-01, 16-17.

**Evaluation of Positions**

Implementing WPAG's position would not allow for the correct measurement of marginal cost. The MCA increases the load during the test year; this increase remains throughout the planning horizon. This enables the measurement of the change in cost associated with the change in resource planning to meet a one-time increase in load. The cost stream over the planning horizon based on the difference between the high and medium load forecast would include costs associated with varying annual load increases that occur beyond the test year. The effect on the levelized marginal cost of load increases in other than the test year is more appropriately considered in subsequent rate periods. Emery, BPA, E-BPA-62R, 7.

BPA's previous marginal cost studies did not consider a specific load increment, but determined the specific resource type that would be planned to meet additional energy or capacity load at least cost during a deficit period. The MCA relies on regional planning and operation models that consider the current surplus as well as the many different resource types that can be used to meet load, such as conservation and cogeneration. The use of planning models allows the MCA to consider how resource plans respond to specific changes in load. Earlier marginal cost studies used the planning models only to identify a particular resource type. The models were not complete enough to analyze the overall planning response to a particular load increment. The current MCA is a refinement to previous marginal cost studies, and it is consistent with them. Emery, BPA, E-BPA-22, 3-4. The use of these regional planning models does not require, as argued by APAC, that the load increment selected take into account the model's assumptions and limitations. Those models are constructed to determine the most efficient way to serve any specified load given operational and planning constraints. Fuqua, BPA, E-BPA-14, 18-27.

For the initial proposal, the MCA assumed that no incremental peakload was added. Emery, BPA, TR 2908-09, 2960-61; BPA, E-BPA-02, 11, 28. PGP claims that the marginal costs would respond to the load shape. This response could take the form of increased running time of combustion turbines and a change in the overall resource mix. Knitter, PGP, E-PG-06, 3. Peakload is an input to the planning models. Annual resource capability is checked against peakload in the LCMM. The hourly SAM considers peakload in the determination of how resources are operated on an hourly basis. Therefore, the loadshape could indeed affect the estimate of marginal cost.

**Decision**

*The 1,000 average megawatt load increment is an appropriate increment of energy load to apply in the MCA. The total marginal cost of generation is more properly calculated by using an increment of load consisting of both peak*
[page 88] *and average components. The peakload component is estimated by applying the system load factor to the 1000 average megawatt increment as recommended by PGP. The procedure is consistent with the approach used in previous marginal cost studies. The MCA determines the total marginal cost of generation and then partitions that total into capacity and energy components.*

### D. Marginal Cost of Capacity

**Issue #1**

*Does BPA use an appropriate methodology to calculate the marginal cost of capacity?*

**Summary of Positions**

In the MCA, the total marginal cost of generation is based on the results of the LCMM and SAM. BPA’s system and the rest of the regional hydrothermal generation system have traditionally been energy constrained rather than capacity constrained. Consequently, the resource planning models select resources primarily to provide for energy needs. The total marginal cost of generation developed in the MCA thus represents the least-cost resource combination to meet energy loads. The resources selected by the LCMM are designed to operate on a continuous basis for energy, but they also augment the supply of capacity generation. Therefore, the total marginal cost of generation includes the cost of both capacity and energy. To separate the total marginal cost of generation into its capacity and energy components, the MCA uses the cost of the least-cost source of capacity as a proxy for the value of the capacity component. A simple cycle combustion turbine represents the least cost source of capacity in the MCA. BPA, E-BPA-02, 11-12; Emery, BPA, E-BPA-22, 8-9; Emery, BPA, TR 2918-20.

APAC opposes BPA's peak-credit approach of partitioning marginal generation costs as being ad hoc, unvalidated, and without precedent. APAC also claims that the use of a peaking unit to evaluate capacity is arbitrary and inconsistent with the results of the LCMM. APAC argues that the LCMM's choice of baseload thermal resources provides a direct statement of the marginal capacity and energy partition. Shanker, APAC, E-PA-04, 22-24. APAC agrees with OPUC that the marginal value of capacity over the next 20 years is zero. Shanker, APAC, E-PA-11R, 1.

WPAG states that because of the lack of capacity constraints in BPA's planning models, the flexibility of the regional hydrothermal system, and the overall surplus resource situation, the true marginal cost of capacity over the planning horizon is zero. WPAG argues that if BPA continues to use the least-cost capacity resource crediting procedure, however, then a one-way radio control water heater load management program represents the least-cost source of capacity. Hutchison, et al., WPAG, E-WA-01, 37-39; Pre-Hearing Brief, WPAG, P-WA-01, 13-14; Initial Brief, WPAG, B-WA-01, 21-22; Reply Brief, WPAG, R-WA-01, 24-25.



OPUC indicates that the MCA considers the energy surplus but not the capacity surplus. OPUC asserts that the marginal cost of capacity should not be based on a combustion turbine, since no combustion turbines will be needed for the foreseeable future. OPUC claims that the marginal cost of capacity is zero in those years with unmarketable surplus capacity. White, OPUC, E-OP-01, 7; Pre-Hearing Brief, OPUC, P-OP-01, 2-3.

The ICP claims that the MCA ignores the forecasted capacity surplus. Weitzel and Sirvaitis, ICP, E-IC-03, 3; Pre-Hearing Brief, ICP, P-IC-01, 3. Moreover, BPA's application of the peak-credit method is not appropriate in a surplus capacity situation. The cost of a combustion turbine as used by BPA is argued to be not an appropriate measure of the marginal cost of capacity during a surplus situation, representing rather an upper bound on the value of additional peaking capacity. Weitzel and Sirvaitis, ICP, E-IC-03, 5, 11; Pre-Hearing Brief, ICP, P-IC-01, 4; Initial Brief, PP&L and PGE, B-GE/PL-01, 4. The ICP recommends that BPA use the opportunity cost of extraregional sales as a measure of the marginal cost of added peaking demand. The shadow prices developed by the LCMM represent the opportunity cost. Weitzel and Sirvaitis, ICP, E-IC-03, 1, 7-10; Pre-Hearing Brief, ICP, P-IC-01, 4; Initial Brief, PP&L and PGE, B-GE/PL-01, 5; Reply Brief, PP&L and PGE, R-GE/PL-01, 2-3.

**Evaluation of Positions**

The simultaneous equation approach used by BPA to partition marginal generation costs between capacity and energy considers the fact that generation projects provide the joint products of capacity and energy. The equations value the joint products of the capacity and the energy resources at their respective marginal costs. Emery, BPA, E-BPA-22, 5-9. The peak-credit approach has been presented and adopted for use in cost classification by each of the six states served by PP&L. Sirvaitis, ICP, TR 3253. In addition, the simultaneous equations used by BPA (BPA, E-BPA-02A, 30-31) can be derived based on standard economic methodology. Weitzel and Sirvaitis, ICP, E-IC-03, 3-5. APAC's assertion that the approach is ad hoc, unvalidated, and without precedent (Shanker, APAC, E-PA-04, 22-23) is thus incorrect; it is also unsupported.

The ICP argues that while peak-credit is an acceptable method, the approach is not appropriate during a surplus period. Weitzel and Sirvaitis, ICP, E-IC-03, 5. This statement was modified during cross examination to mean that a peak-credit approach can be used during a surplus period if properly constructed. Sirvaitis, ICP, TR 3253-54. The ICP claims that by not considering the capacity surplus, BPA's peak-credit method overstates the marginal cost of capacity. Weitzel and Sirvaitis, ICP, E-IC-03, 5. PP&L and PGE estimated this overstatement by comparing the marginal cost of capacity and energy calculated during a surplus (the MCA results) and during a deficit (the 1983 TDLRIC results). Initial Brief, PP&L and PGE, B-GE/PL-01, 2-3. A comparison of the results of the two marginal cost studies shows that the marginal cost of energy declined more than did the marginal cost of capacity. Initial Brief, PP&L and PGE, B-GE/PL-01, 2-3; Emery, BPA, TR 2870-81, 2898-2901.

[page 90]

BPA constructs resources and incurs cost to meet energy load. Initial Brief, PP&L and PGE, B-GE/PL-01, 4; BPA, E-BPA-02, 11. As a result of BPA constructing for energy needs and consequently incurring energy related costs, BPA's long-run marginal costs are more sensitive to an energy surplus than to a capacity surplus. After adjusting the marginal costs between the two marginal cost studies to account for differences in plant factor and inflation, both the marginal cost of energy and capacity in the MCA declined from the levels calculated in the 1983 TDLRIC Analysis. Initial Brief, PP&L and PGE, B-GE/PL-01, 3; Emery, BPA, TR 2955. This decline in the marginal costs of both energy and capacity is the expected result given the incorporation of the surplus into the MCA. Emery, BPA, E-BPA-22, 3-4. However, no evidence was provided to show that the respective declines in each component should be similar, especially since costs are incurred primarily for energy reasons.

A number of parties indicate that the marginal cost of capacity during a surplus period should be essentially zero, apparently ignoring the fact that resources brought on line for energy reasons necessarily provide an increment of capacity. BPA's capacity surplus through the planning horizon is partially a result of the incremental capacity associated with the baseload resource capability added for energy reasons. Emery, BPA, E-BPA-62R, 4. The addition of this capacity increment allows BPA to defer the purchase of additional peaking capability. Since the capacity and energy components of the incremental resource capability cannot be treated independently, the planning models will continue to indicate a capacity surplus over time. These models will not indicate that capacity resource purchases have been avoided. Therefore, a capacity surplus situation does not imply that the additional capacity has no value. Emery, BPA, E-BPA-62R, 4; Reply Brief, PGE and PP&L, R-GE/ PL-01, 2.

To account for this situation, some parties offered alternate methods to value capacity. APAC suggests that the baseload thermal unit selected by the LCMM provides a direct statement of the marginal costs. Shanker, APAC, E-PA-04, 23. APAC does not, however, describe how the marginal costs of the capacity and energy associated with the baseload thermal plant could be separated.

The ICP urges that the opportunity cost as measured by the LCMM shadow prices be used to value capacity. Weitzel and Sirvaitis, ICP, E-IC-03, 1. However, the shadow prices presented in the ICP testimony as representative of the marginal cost of capacity equal zero. Weitzel and Sirvaitis, ICP, E-IC-03, 9. The ICP position was later clarified to mean that the marginal cost of capacity could range from zero to the cost of a combustion turbine. Sirvaitis and Weitzel, ICP, TR 3244-46, 3258-61, 3266-67. The appropriate marginal cost could be determined, it was argued, by considering additional capacity sales and by modifying the LCMM to determine the value of additional surplus capacity. Weitzel and Sirvaitis, ICP, E-IC-03, 11-12. Contrary to PGE and PP&L suggestions, there is more to making these modifications than simply "flipping a programming switch." Reply Brief, PGE and PP&L, R-GE/PL-01, 3. While additional extraregional capacity sales can easily be
[page 91] added, the determination of the level and type of sales to assume is more difficult. The analysis contained in the ICP testimony assumed an additional 2,000 megawatt summer capacity sale. Weitzel and Sirvaitis, ICP, E-IC-03, Attachment 2. The resulting zero shadow price for capacity in the ICP testimony was argued by PGE and PP&L to be related to the assumed low level of extraregional sales. Reply Brief, PGE and PP&L, R-GE/PL-01, 3. However, there was no indication by PGE and PP&L as to why the 2,000 megawatt sale was low; how BPA should determine the appropriate level of capacity sales to assume; or why summer sales versus annual sales are more appropriate. In addition, the value of surplus formula offered by the ICP in testimony provided no information on how to quantify the declining marginal value. Weitzel and Sirvaitis, ICP, E-IC-03, Attachment 3. It was simply argued that this value would be an input to the model. Weitzel and Sirvaitis, ICP, E-IC-03, 12. Considerable effort would be required to determine if, and consequently, how, to implement the ICP proposal since the required information is not currently available to BPA. This lack of information is acknowledged by the ICP’s conclusion that a careful study of the demand for and supply of peak capacity should be conducted. Weitzel and Sirvaitis, ICP, E-IC-03, 12. However, in the absence of such a study, the ICP proposals cannot be implemented.

The selection of the appropriate capacity resource depends not only on the cost of the resource but also on the characteristics of the peakload to be served by the resource. BPA's peakload includes peakloads with an extended duration, such as industrial loads, and peakloads of shorter duration, such as utility loads with a high residential load base. Contrary to the WPAG position (Reply Brief, WPAG, R-WA-01, 24), all loads occurring during the peak period, whether contractually limited or not, contribute to the peakload faced by BPA. Consequently, the overall incremental peakload faced by BPA takes on the characteristics of the average peakload served. In addition, the incremental capacity resource selected must exhibit operational characteristics sufficient to provide for the incremental peakload. The residential water heater load management program recommended by WPAG (Hutchinson, et al. , WPAG, E-WA-01, 37-39) could provide the least-cost source of incremental capacity for peakload exhibiting short duration. However, this program would not satisfy the peaking needs of BPA's average peakload.  Therefore, the residential water heater load management program cannot be considered as BPA's overall least-cost source of incremental capacity.  The load management program is analyzed in the MCA, however, because load management is a viable capacity resource that PF customers could substitute for capacity purchases from BPA.  The resulting classification percentages are used to reclassify the costs allocated to the PF rate.  See Chapter VIII, Section C.

**Decision**

*The peak-credit approach using a combustion turbine as the peaking resource is an appropriate method for determining the marginal cost of capacity during a surplus period.  A residential water heating program could be argued to handle successfully the additional peak needs of that portion of*
[page 92] *BPA's load exhibiting limited duration, such as priority firm loads.  This program would not be as successful with BPA's overall incremental peak, which includes loads exhibiting longer peak duration.*

**Issue #2**

*Does BPA properly calculate the capacity reserve factor?*

**Summary of Positions**

The MCA uses a composite capacity reserve rate based on the required levels of forced outage reserves for each resource acquisition in the MCA.  The capacity reserve factor is used to adjust the marginal cost of capacity to consider the reduction in resource capability due to forced outage reserve requirements.  BPA, E-BPA-02, 31.

WPAG suggests that BPA should use a 5 percent reserve requirement, which would represent the forced outage rate for peaking facilities.  WPAG claims that combustion turbines have relatively lower unit reserve requirements; therefore, BPA has overstated the cost of capacity reserves.  Hutchison, et al., WPAG, E-WA-01, 40; Pre-Hearing Brief, WPAG, P-WA-01, 14-15; Initial Brief, WPAG, B-WA-01, 23-24.

**Evaluation of Positions**

The capacity reserve factor in the MCA is based on the capacity reserve levels associated with the incremental resources acquired by the LCMM to serve incremental load.  These resources consist of baseload coal facilities and conservation.  Emery, BPA, E-BPA-62R, 7-8; BPA, E-BPA-02A, 26.  The required level of additional capacity reserve is a function of the resources acquired.  Baseload coal plants require a 15 percent reserve.  BPA, E-BPA-02A, 26.  As noted by WPAG, combustion turbines require a 5 percent reserve.  Hutchison, et al., WPAG, E-MA-01, 40.

The combustion turbine is used in the MCA to value the capacity component of the total marginal cost of generation.  This total cost is based on the cost of incremental resources selected by the LCMM.  The MCA does not presuppose that BPA will construct a combustion turbine. Rather, it uses the combustion turbine as a proxy for the value of capacity.  Emery, BPA, TR 2918-20.  To use the 5 percent reserve factor recommended by WPAG would understate the capacity reserves required for those resources actually selected by the LCMM to meet incremental load.  Emery, BPA, E-BPA-62R, 7-8.

**Decision**

*BPA has correctly determined capacity reserve requirements for use in calculating marginal cost.  A weighted average reserve requirement correctly values the added reserves that incremental resources would require.*

[page 93]

**Issue #3**

*Does BPA properly calculate the plant factor used for the combustion turbine?*

**Summary of Positions**

A 1.3 percent plant factor was used for the combustion turbine in the initial MCA.  This value is based on results from SAM for the Plus 1,000 Case.  BPA, E-BPA-02, 31.  The value was derived by averaging the expected operation of all the combustion turbines modeled in SAM over the 18-year planning horizon.  BPA, E-BPA-02A, 25.

WPAG argues that because the plant factor calculation in the initial MCA was a simple arithmetic average all the combustion turbines are implied to be similar in size.  WPAG recommends that a weighted average calculation would be more appropriate.  Hutchison, et al., WPAG, E-WA-01, 39; Pre-Hearing Brief, WPAG, P-WA-01, 14; Initial Brief, WPAG, B-WA-01, 22-23.  In addition, WPAG notes that the initial plant factor calculation included the Frank Bird plant.  This plant is a steam plant, not a combustion turbine, and should be excluded from the sample used to calculate the plant factor.  Hutchison, et al., WPAG, E-WA-01, 39-40; Pre-Hearing Brief, WPAG, P-WA-01, 14.

The DSIs argue that the combustion turbine plant factor is understated.  The BPA analysis does not use the hourly version of SAM, which recognizes plant operation to meet loads that vary continuously.  Carter, DSI, E-DS-07, 5; Initial Brief, DSI, B-DS-01, 127.  If BPA were not able to use the hourly SAM, the DSIs recommend an alternative based on the amount of energy actually delivered to BPA's firm capacity purchasers.  The result of this analysis indicates a combustion turbine plant factor of 9.6 percent.  Carter, DSI, E-DS-07, 6.

PGP argues that the inclusion of all nine regional combustion turbines in the MCA is not realistic.  PGP recommends that BPA perform a sensitivity analysis to select the most economically and operationally efficient group of available combustion turbines.  This analysis would produce a much smaller number of combustion turbines available for SAM to use. Knitter, PGP, E-PG-06, 3-4; Pre-Hearing Brief, PGP, P-PG-01, 11; Initial Brief, PGP, B-PG-01, 17.  PGP also argues that the combustion turbines considered in the MCA are regional in nature and not operated solely for BPA, so it is unreasonable to assume that the combustion turbines would be operated by their owners only 1.3 percent of the time.  Knitter, PGP, E-PG-06, 4.

## Evaluation of Positions

The DSI argument concerning the use of firm capacity purchases is based on an analysis of monthly firm capacity deliveries for three investor owned utilities during the period 1978-79 through 1981-82. Carter, DSI, E-DS-07, 8. WPAG states in response that the MCA is a forward-looking analysis and the use of historical information is inappropriate. Hutchison, et al., WPAG, E-WA-02R, 21. The ICP and PP&L and PGE note that firm capacity purchases are [page 94] not a good proxy for combustion turbine operation because firm capacity purchases are geared to the operation of baseload thermal resources. Weitzel and Sirvaitis, ICP, E-IC-15R, 2-3; Initial Brief, PP&L and PGE, B-GE/PL-01, 8. The use of firm capacity purchases as a proxy for combustion turbine operation would over state the load factor associated with the use of a high energy-cost combustion turbine.

The PGP argument disregards the fact that all nine combustion turbines currently exist in the region and are available to meet regional load. The argument also disregards the fact that SAM determines the most economic way to operate a given resource mix, including combustion turbines, to meet regional load. BPA, E-BPA-02, 9-10. SAM will select and operate available resources on the basis of their operational and economic efficiency. The costs developed in the MCA must be based on a consideration of the cost of all resources available to meet load. To do otherwise would not consider actual resource realities.

The purpose of the hourly version of SAM is to adjust the results of the energy model to reflect the hourly shape of regional load. This adjustment could take the form of increased combustion turbine operation. The hourly model is available and is used in the determination of the value of reserves. Emery, BPA, TR 2864-68; Initial Brief, DSI, B-DS-01, 127-28.

## Decision

*All regional combustion turbines are included in the calculation of the combustion turbine plant factor in the MCA. This calculation is a weighted average of those combustion turbines as recommended by WPAG. However, the Frank Bird plant is a steam facility and not a combustion turbine; therefore, it is not included in the plant factor calculation. The MCA incorporates the results of the hourly SAM as recommended by the DSIs.*

## E. Marginal Cost of Transmission

## Issue #1

*Does BPA appropriately classify transmission costs in the MCA?*

## Summary of Positions

The MCA classification methodology for transmission network costs separates the capacity and energy components of cost on the basis of an analysis of the projected network investments. Investments made to correct transmission thermal and voltage problems which appear during the

peak period are classified to capacity. Generation-integration facilities and facilities installed to transmit power integrated from new generating resources are classified in the same proportion as the total marginal cost of generation. Investments made to reduce energy transmission losses are assigned to energy. BPA, E-BPA-02, 18-19, 36-37.
[page 95]

SCE argues that there is no valid reason to apply the classification percentages for generation costs to the classification of generation-related transmission cost. For generation, capital and fuel can be substituted in the production process. A utility can choose to incur additional capital costs in order to reduce its fuel expenses or vice versa. SCE claims that such substitution is usually not possible for transmission equipment. Whether generating units are installed for peak or for energy reasons, virtually the same transmission investments will be incurred to integrate the generating units. Therefore, generation-related transmission cost should not be classified according to generation capital substitution theories. Waddell, SCE, E-CE-02A, II11-II12.

**Evaluation of Positions**

Investment in transmission facilities is made for a variety of reasons. In the MCA, transmission investment that is solely related to the addition of a generation facility is classified consistently with the generation facility. Generating facilities provide both energy and capacity. This energy and capacity cannot be delivered to the load without integrating the generating resource into the transmission grid and investing in facilities to transmit the power integrated from new generating resources. As indicated by SCE, the investment for generation-integration facilities does not vary significantly by generating resource. BPA is not making capital substitution arguments since the decision to build a generating resource requires the decision also to build a certain amount of transmission capability. Both generation-integration and network facilities are required. These two decisions are inseparable. The total cost of meeting an increment in load includes both generation and transmission cost. Emery, BPA, E-BPA-22, 6-7. The reasons for incurring the transmission investment, i.e., to serve an increment of capacity or energy load, are the same as those for incurring generation investment. Consequently, the capacity/energy classification for generation can be applied directly to the transmission investment that would not have occurred in the absence of the generation investment.

**Decision**

*The classification of transmission costs in the MCA is appropriate. The analysis considers the fact that generation-integration investment is intimately tied to the generation investment and delivers the same amounts of capacity and energy as does the generating resource.*

**F. Selection of Costing/Pricing Periods**

**Issue #1**

*Are the results of the Loss of Load Probability (LOLP) analysis appropriate for use in selecting seasonal capacity costing/pricing periods?*
[page 96]

**Summary of Positions**

In the MCA, LOLP data provide the basis for selecting seasonal costing time periods for generation capacity costs. LOLP data depict the relationship between the system's peakload and the available peaking generation. A high LOLP indicates that the difference between peaking capability and peakload is relatively small. A low LOLP indicates an adequate supply of peaking capability relative to peakload. An increase in peakload during a period of low LOLP is less likely to require acquisition of additional peaking capability. However, increased peakload during a period with a high LOLP could cause the utility to consider constructing additional peaking resources. Since the purpose of time differentiation is to determine the period of time most likely to cause incurrence of different costs, the LOLP analysis is a method of determining costing/pricing periods for generation capacity cost. BPA, E-BPA-02, 22-24.

WPAG argues that seasonal differentiation of BPA's capacity charge is not appropriate and that a uniform capacity charge should be instituted. Hutchison, et al., WPAG, E-WA-01, 41; Pre-Hearing Brief, WPAG, P-WA-01, 15; Initial Brief, WPAG, B-WA-01, 24. WPAG claims that the characteristics of BPA's hydrothermal system are such that BPA does not incur higher operating costs to meet peak period loads. A thermal based system operates successively more expensive resources as the peakload increases. WPAG states that BPA, however, uses the flexibility of the hydro system to meet peak requirements at essentially no cost. Since BPA does not experience substantially different capacity costs from season to season, the basic rationale for seasonally differentiating capacity costs is not present on the BPA system. Hutchison, et al., WPAG, E-WA-01, 41-42; Pre-Hearing Brief, WPAG, P-WA-01, 15-16; Initial Brief, WPAG, B-WA-01, 25. WPAG also notes that BPA currently has projected a surplus of capacity over much of the MCA planning horizon and BPA has no plans to install peaking units. Hence, BPA is not expecting to incur additional peak-related costs. Hutchison, et al., WPAG, E-WA-01, 42. WPAG also argues that LOLP data are not useful for ratesetting given the nature of the BPA system and given the volatile nature of the index. Hutchison, et al., WPAG, E-WA-01, 43-44; Pre-Hearing Brief, WPAG, P-WA-01, 16-17; Initial Brief, WPAG, B-WA-01, 25-26.

NIU has expressed concern in past rate cases about the use of LOLP in determining the seasonal assignment of capacity costs, but indicates here that the index has been used since 1979, that it has shown stability, and that a better index has not been developed. Therefore NIU supports the LOLP analysis as a reasonable index for seasonally differentiating capacity costs. Hittle, NIU, E-NI-02, 2; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 2-3.

SCE argues that the LOLP analysis in the MCA is deficient since it does not consider periods of spill. SCE indicates that spill periods should be identified as separate costing periods. Waddell, SCE, E-CE-02A, II2-II5.

[page 97]

**Evaluation of Positions**

WPAG notes that capacity charges should theoretically be seasonally differentiated to account for seasonal cost variation in serving peakload. WPAG argues that BPA, because of hydro flexibility and surplus conditions, does not incur seasonally varying costs. This argument is essentially short run in nature. A uniform capacity charge would indicate that an increase in peakload during any portion of the year will strain the capability of the system inexactly the same manner. Emery, BPA, E-BPA-62R, 8. The LOLP data developed by the Coordination Agreement Reserve Planning (CARP) model clearly indicate that BPA does experience a difference between seasons in its ability to meet peakload. BPA, E-BPA-02, 59; BPA, E-BPA-02A, 57-63; Emery, BPA, E-BPA-62R, 8. The marginal cost of capacity is seasonalized on this basis to show how capacity costs would be incurred over time. A levelized capacity charge would provide incorrect information and would be contrary to WPAG's assertion that the MCA provides useful information concerning how a utility's cost changes over time. Hutchison, et al., WPAG, E-WA-01, 31. Further, the MCA is a long run analysis that extends beyond the surplus period, since customers will be making investment decisions today that affect their loads over the entire planning horizon. WPAG implies that seasonal differentiation of capacity is appropriate during deficit periods. Initial Brief, WPAG, B-WA-01, 24. To provide proper indications of long run cost incurrence requires proper capacity cost seasonality over the long run.

On a practical level, LOLP is a useful measure. The CARP model develops the LOLP data used in the MCA. This model is based on language contained in the Pacific Northwest Coordination Agreement. BPA, E-BPA-02, 22-23; Emery, BPA, E-BPA-22, 12-13. The CARP is used in the determination of critical peaking periods and for reserve planning purposes.

SCE argues that the LOLP analysis has not considered periods of spill. The hydro generation data input to the CARP model is developed in BPA's hydro regulation studies. These studies take into account the effect of spill conditions on BPA's hydro capability. BPA, E-BPA-06, 21-22.

**Decision**

*The results of the LOLP analysis are used in the MCA to seasonalize the marginal cost of capacity. The MCA is a long term analysis that should account for long term cost relationships. The LOLP data have been in use since 1979 and have shown reasonable levels of stability. The long term capacity relationships embodied in the MCA are important and should be maintained.*

**Issue #2**

*Does the LOLP analysis accurately consider expectations of future capacity sales?*

[page 98]

**Summary of Positions**

The LOLP data used in the MCA are calculated in the Coordination Agreement Reserve Program. The CARP considers the capacity of BPA's hydro and thermal resources, hydro and thermal maintenance schedules, peakload for the Federal system, and Federal exports and imports. In the initial MCA, the level of surplus sales assumed in the CARP analysis was 200 MW. In addition, all export contracts with the Southwest were assumed to lapse on their various expiration dates. BPA, E-BPA-02, 22-24; BPA, E-BPA-02A, 57-63.

WPAG maintains that the CARP analysis does not consider the proper level of surplus firm power sales assumed in the COSA. WPAG also indicates that the CARP does not consider any capacity export sales after 1987. In order to account for BPA's efforts to market capacity, WPAG recommends that some export capacity sales should be included and shaped over the year in a manner consistent with existing export contracts. Hutchison, et al., WPAG, E-WA-01, 44.

**Evaluation of Positions**

BPA acknowledges that the level of firm surplus sales included in the initial MCA was not consistent with the COSA. Emery, BPA, E-BPA-22, 13; Emery, BPA, TR 2906, 2953. The change in the level of surplus sales from 200 MW to 850 MW in the COSA occurred too late in the development of the initial proposal to be considered in the MCA. Emery, BPA, E-BPA-22, 13. WPAG argues that the assumptions should be consistent between the two studies. This is correct.

The assumption contained in the CARP concerning the expiration of the export contracts reflects currently known conditions. WPAG states that some effort will likely be made to renegotiate or to replace some of those contracts. This is particularly true given BPA's interest in marketing additional capacity. Pollock, BPA, E-BPA-11, 10-11.

**Decision**

*The surplus firm sales included in the MCA are consistent with the final COSA. The MCA is a forward looking analysis that considers future costs and situations. The current assumption in the MCA concerning the complete cessation of capacity export contracts is unsupportable given BPA's current marketing efforts. Some capacity exports should be included in the CARP analysis throughout the planning horizon.*

**Issue #3**

*Does BPA appropriately determine the time differentiation of marginal energy cost?*

[page 99]

**Summary of Positions**

To seasonally differentiate energy costs, the MCA considers the operating and planning characteristics of BPA's hydrothermal system. Under critical water conditions, an increase in energy load could be served with any available surplus on the hydro system, or additional baseload facilities could be constructed. On the Federal hydro system, surplus energy is produced under critical water conditions during the month of May as a result of the water budget. BPA, E-BPA-06, 22. Increased energy load during May could be served with this. surplus at no additional cost to BPA. In months other than May, increased energy loads would require additional baseload facilities. Since baseload facilities are designed to operate throughout the year, the cost of providing energy from these facilities is the same for BPA for each hour of the year. Consequently, the seasonal energy costing period is all months except May. BPA, E-BPA-02, 21, 37-39.

SCE argues that the MCA fails to recognize the appropriate time differentiation of energy. SCE recommends that energy costs be assigned to periods according to the probability that the system will be unable to produce sufficient energy in those periods. Assigning costs proportionately to all kilowatthours is incorrect if operating costs vary throughout the year. Waddell, SCE, E-CE-02A, II8-II11.

NIU claims that equal marginal costs of energy overall months except May assumes that hydro storage is sufficient for the system to be managed to equalize incremental costs in all seasons.  NIU asserts that BPA has not substantiated the claim that RPA can levelize hydro during critical water.  Results of SAM clearly indicate to NIU that different resources will be operated, and thus different incremental costs will be incurred, during the winter and summer seasons.  Gates, NIU, E-NI-03, 13-15; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 4, 7-8; Initial Brief, NIU, 8-NI-WS-NE-01, 5-6.

**Evaluation of Positions**

The MCA considers the fact that incremental baseload facilities will be used to meet incremental energy load under conditions of critical water.  The cost of operating a baseload facility does not vary over the day or year.  Emery, BPA, TR 2889-92.  This position does not require that the capability of the hydro system be levelized throughout the year as argued by NIU.  Emery, BPA, TR 2892.  The existing hydro system is assumed to have sufficient capability to be operated to provide load-following services over the long term.

Both the NIU and SCE arguments are based on short run considerations.  The NIU position is based on results of the SAM.  NIU attempts to evaluate system energy costs on the basis of short-run thermal production costs and how resources are stacked to meet load.  Gates, NIU, E-NI-03, 13-15.  It is difficult to apply this approach to BPA's primarily hydro system.  The production costs of hydro and its use to meet load are not explicitly detailed in SAM output.  It is also difficult to value hydro capability since it is [page 100] used to follow load and, therefore, may be the last resource brought online but still have the lowest production costs.  Determining the time of use of hydro capability and evaluating that time of use at its variable production cost would undervalue hydro capability used for peak or intermediate load purposes.  Some form of opportunity cost may need to be considered when valuing hydro capability.  This concept was argued by NIU with regard to seasonal energy cost characteristics as applied in the COSA.  Gates, NIU, E-NI-03, 7-11; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 5-7; Initial Brief, NIU, B-NI-WS-NE-01, 2-5.  NIU itself acknowledges the difficulty of implementing its proposal and supports BPA's basic methodology.  Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 4, 8.

The SCE position considers short-term surplus and spill conditions.  While spill or forced sale conditions do exist on the BPA system, an optimally planned system over the long run would minimize such conditions.  BPA presented evidence that, on a planning basis, forced sale amounts would drop considerably following operating year 1987 and become zero on a monthly basis following operating year 1993.  Fuqua, BPA, E-BPA-14, Attachment 7, 17.  In addition, the MCA includes consideration of deficit periods as well as surplus conditions whereas SCE considers only surplus periods.

**Decision**

*The methodology employed in the MCA to determine the seasonality of marginal energy costs is appropriate and supported by the evidence.  The marginal cost of energy is zero in May due to the implementation of the water budget.  The marginal cost of energy is uniform over the* *remaining months due to the addition of baseload thermal facilities to meet projected incremental load.*

**Issue #4**

*Does BPA appropriately determine the seasonality of marginal transmission network costs?*

**Summary of Positions**

The MCA indicates that transmission network marginal cost should not be seasonally differentiated. Seasonal differentiation of the transmission system must account for seasonally varying load and resource patterns, outage rates, restoration times, and facility capabilities. Due to the size and diversity of BPA's transmission system, seasonal differentiation would necessarily be location specific and not applicable to the system as a whole. BPA, E-BPA-02, 25-26.

NIU suggests that BPA should seasonalize transmission network costs. NIU recommends a method that determines the average annual unit cost of transmission and then seasonally varies that unit cost as a ratio of the two seasons. This proposed method uses the seasonal load variation on the
[page 101] transmission system and allocates the annual unit revenue requirement based on seasonal load variations. Hittle, NIU, E-NI-02, 3-7; Pre-Hearing Brief, NIU, P-NI-WS-NE-01, 3, 10-11; Hittle, NIU, E-NI-02S, 6; Initial Brief, NIU, B-NI-WS-NE-01, 7-9.

**Evaluation of Positions**

A supportable seasonal differentiation of transmission costs requires analysis of load and resource patterns, outage rates, restoration times, and facility capabilities. The analytic tools necessary for such an analysis are not available. Emery, BPA, E-BPA-62R, 9; Emery, BPA, TR 2896. Moreover, these factors vary with the physical location of the transmission facilities. This makes it difficult to consider accurately the correct overall system seasonal differentiation for the development of rates. Emery, BPA, E-BPA-62R, 9-10.

The NIU position relies on transmission system loadings and seasonal characteristics of generation capacity to seasonally differentiate transmission costs. Hittle, NIU, E-NI-02, 3-7; Hittle, NIU, E-NI-02S, 6. Seasonal characteristics of generation capacity costs do not coincide with transmission cost seasonality. The LOLP methodology used to develop seasonality of generation capacity cost does not consider the transmission system; this makes it in applicable for seasonalizing transmission costs. Emery, BPA, E-BPA-62R, 9. As WPAG points out, it is not appropriate to use only transmission system loads in seasonalizing transmission costs; both loads and resource capabilities must be considered in the analysis. Hutchison, et al., WPAG, E-WA-02R, 27-28.

NIU also claims that because BPA diurnally differentiates transmission costs on the basis of transmission load, the load measure can be used to seasonally differentiate transmission costs. Initial Brief, NIU, B-NI-WS-NE-01, 7-9. BPA indicates that while the factors that must be considered in diurnally and seasonally differentiating transmission costs are similar, their relative importance varies.  Emery, BPA, TR 2897.  Daily load variations are the most significant factor when considering diurnal variations.  Facility capabilities and resource patterns are more important than load variations on a seasonal basis.  Thus, load is a much better proxy for diurnal transmission cost variation than for seasonal variation.  Emery, BPA, TR 2969-70.

**Decision**

*BPA does not seasonally differentiate its marginal cost of transmission.  To do so would require consideration of location specific usage and outage patterns, and facility capabilities.  BPA has not developed a method to incorporate those considerations, nor has a sufficiently comprehensive method been proposed on the record.*

[page 102]

**Issue #5**

*Does the MCA properly identify the diurnal costing/pricing periods for generation capacity?*

**Summary of Positions**

In the MCA, BPA's historical hourly firm loads are analyzed and used as the basis for the diurnal costing/pricing periods for the marginal cost of generation capacity.  Hourly LOLP data could be used as an indicator of diurnal capacity cost variation, but hourly LOLP data are not available for the BPA system.  Hourly loads are used because the data are available as a proxy for LOLP data.  BPA, E-BPA-02, 24-25.

SCE argues that the capacity costing period identified in the MCA is inconsistent with the number of hours of operation assumed for the combustion turbine used to calculate the marginal cost of capacity.  SCE claims that the unit assumed to supply demand-related power would operate in less than 2.5 percent of the hours that cause demand-related capacity costs.  Waddell, SCE, E-CE-02A, II7-II8.

**Evaluation of Positions**

In developing the diurnal capacity periods in the MCA, hourly loads are used as a proxy for LOLP data.  LOLP data measure the likelihood that loads will exceed resources, considering such items as maintenance and forced outages.  BPA, E-BPA-02, 22.  The period with the highest LOLP in any given day will generally correspond to the period in that day with the highest load.  BPA, E-BPA-02, 24.  The statistical analysis of loads in the MCA identifies those hours of the day that are not significantly different from the single peak hour.  The broad peak period indicates that BPA's loads are high during a large portion of each day.  Loads could exceed resources during any of those hours.  The implication is that an increase in load during any of those hours could put BPA in a situation of having in sufficient resources and of needing to acquire additional peak resources.  BPA, E-BPA-02, 24-25, 40-41.

SCE attempts to establish a relationship between the number of hours of operation embodied in the estimate of marginal capacity cost and the number of hours designated as the capacity costing/pricing period.  Waddell, SCE, E-CE-02A, II8.  The number of hours of combustion turbine operation embedded in the marginal cost of capacity represents the number of hours of

operation associated with the delivery of capacity. Any required resource operation after that point is considered to be operation for energy reasons and the costs are therefore not included as capacity costs. BPA, E-BPA-02, 11-12. Thus, SCE argues that the number of hours of peak resource operation to meet an increase in peak load should equal the number of hours in which there is a high probability that loads will exceed resource capability. There is no reason to expect the relationship argued by SCE to exist. The diurnal capacity costing periods indicate when additional resources may be needed to respond to increased load. The number of hours of peak resource operation in
[page 103] the marginal cost of capacity indicates resource operation for peak needs if an increase in peakload during any of the peak hours forced BPA to acquire an additional resource. These concepts are related but they are not equivalent.

**Decision**

*The MCA properly identifies the diurnal costing/pricing periods for generation capacity. Hourly load data are a useful proxy for LOLP data, since hourly LOLP data are not available.*

[page 105]

## V. COST OF SERVICE ANALYSIS

### A. Introduction

The purpose of the Cost of Service Analysis (COSA) is to assign responsibility to each of BPA's customer classes for costs incurred in providing service to those customers. The COSA also aids in determining the adequacy of rates currently in effect, and provides a basis for designing new rates that will recover from each customer class the costs assigned to them. The analysis performed in the COSA consists of five basic steps: (1) functionalization apportions costs between the functions of generation and transmission; (2) segmentation divides transmission costs among the segments of the Federal Columbia River Power System; (3) classification divides generation and transmission costs between capacity and energy; (4) seasonal differentiation apportions energy and capacity costs to winter and summer; and (5) allocation apportions costs to rate classes.

### B. Seasonal Differentiation

**Issue**

*Has BPA appropriately seasonally differentiated energy costs?*

**Summary of Positions**

All energy costs in the COSA are seasonally differentiated based on the winter and summer seasonal splits developed for the FBS resource pool. FBS energy costs are seasonally differentiated in a two-step process. First, the energy seasons are determined based on monthly energy withdrawals from storage. Then costs are apportioned to the seasons. Storage costs are assigned to the seasons on the basis of energy produced from storage in each season. All other energy costs are apportioned to the winter and summer seasons according to projected firm energy produced by the FBS in each season, excluding May. BPA, E-BPA-01, 21-22; Ratchye, BPA, E-BPA-28, 2-4.

NIU proposes modifications to BPA's seasonal energy differentiation methodology. NIU argues that BPA undervalues the cost of storage apportioned to the winter season by not recognizing the opportunity cost of storage. Gates, NIU, E-NI-03, 9-11. NIU claims that baseload thermal resources are run in the summer to allow for storage of water to meet winter energy loads. Therefore, NIU recommends that the avoided cost of thermal resources be added to the cost of hydro storage to determine the seasonal energy splits. Gates, NIU, E-NI-03, 9-10; Initial Brief, NIU, B-NI-WS-NE-01, 4-5. NIU also proposes that conservation costs be seasonally differentiated on the basis of the [page 106] amount of conservation savings projected to occur in each season. Hittle, NIU, E-NI-02, 7-8. Finally, NIU notes that BPA failed to update the seasonal splits in supplemental testimony when the load data changed. Hittle, NIU, E-NI-02S, 3-4; Gates, NIU, E-NI-03S, 2-4.

WPAG supports BPA's methodology for seasonally differentiating energy costs and opposes NIU's scheme to reflect a shadow price for hydro storage in the seasonal energy splits. WPAG claims that to apply shadow pricing appropriately, marginal costs for all FBS facilities must be analyzed. Hutchison, et al., WPAG, E-WA-02R, 26; Reply Brief, WPAG, R-WA-01, 26.

**Evaluation of Positions**

BPA's method of seasonally differentiating energy costs in the COSA recognizes the characteristics of the existing operating system as well as of the long-run marginal cost of energy. Ratchye, BPA, E-BPA-28, 3. BPA's procedure accounts for the ability of the FBS to follow seasonal variations in load by considering hydro storage characteristics and the associated cost together with actual energy produced. Ratchye, BPA, E-BPA-28, 2-3. The NIU position assumes that the thermal resources on the system are always operated during the summer to allow for the storage of water for winter use. This argument disregards the fact that thermal resource maintenance occurs during the period March through July. Thus, it cannot be said that thermal resources are operated during the summer to increase hydro storage. Emery, BPA, E-BPA-62R, 10-11. To develop a proper measure of avoided cost would require analysis of the operation of the entire system. Hutchison, et al., WPAG, E-WA-02R, 26; Reply Brief, WPAG, R-WA-01, 26. Such an analysis would consider storage benefits as well as benefits associated with thermal maintenance scheduling. The NIU proposal does not consider all of these factors.

NIU further asserts that it is appropriate to seasonally differentiate conservation costs on the basis of the amount of savings projected to occur in each season. Hittle, NIU, E-NI-02, 7-8. NIU admits, though, that the data on conservation savings by program by month are not available for this analysis. Hittle, NIU, E-NI-02, 7-8. Moreover, BPA's method of seasonal differentiation recognizes that all of BPA's resources -- thermal, hydro, and conservation -- are operated as a combined system to meet total loads. NIU did not justify singling out a particular resource cost for special treatment in seasonally differentiating costs.

NIU notes that BPA did not update the seasonal splits based on the new load forecast presented in BPA's supplemental testimony. Hittle, NIU, E-NI-02S, 3-4. NIU claims that the

changed load and resource balance affects the storage drawdowns occurring in each season. Gates, NIU, E-NI-03S, 1-2. NIU is correct that the new load forecast affects the seasonal splits. Ratchye, BPA, TR 3107. However, NIU's claims regarding storage drawdowns are incorrect. The data used in this analysis on monthly energy withdrawals from storage are historical and thus are not affected by the test year load and resource balance. BPA, E-BPA-01, 21.
[page 107]

**Decision**

*BPA continues to seasonally differentiate all energy costs on the basis of historical monthly energy withdrawn from storage and the projected firm energy produced in each season, excluding May. This procedure considers the operating characteristics of the existing system and reflects the results of the Marginal Cost Analysis. The seasonal splits developed for the final proposal incorporate the load forecast used in the final proposal.*

## C. Allocation of Costs

### 1. Size of the Federal Base System

**Issue #1**

*How should BPA's firm hydro capability for the test year be determined?*

**Summary of Positions**

BPA's test year hydro capability is calculated using a levelized monthly hydro amount equivalent to the critical period average hydro energy output, exclusive of amounts of energy production during the months of May in the critical period. BPA uses a critical period that is 42 months long (September 1986 through February 1990). The levelized hydro output is calculated as the average of 39 months of hydro output (42 months excluding three May amounts during the critical period). For purposes of calculating the monthly surplus in the critical period and the test year, BPA assumes a levelized hydro output equivalent to the 39 month average in each month of the critical period, except May. During the months of May in the critical period, and in the single month of May in the test period, BPA assumes an amount of Federal hydro generation sufficient to balance firm loads with firm resources. This assumption results in no surplus firm power being identified for the months of May.

PGP argues that BPA misrepresents the size of the Federal base system. It contends that BPA erred in assuming that no surplus firm power would be generated or sold during May. Initial Brief, PGP, B-PG-01, 32. The PGP claims that because BPA does not recognize generation of surplus firm power during May, the size of the FBS is understated by approximately 300 MW, and thereby BPA allocates the cost of more expensive resources to loads that should be served by a larger FBS. Initial Brief, PGP, B-PG-01, 32.

PGP claims that BPA's exclusion of Federal hydro resources in excess of what is required to serve firm loads in May constitutes a load defined FBS. It argues that BPA is not permitted to use a load defined FBS. PGP asserts that BPA has no discretion in calculating the amount of output from the Federal hydro resources. PGP argues that the size of the FBS hydro energy production is whatever the resources produce, and resource size is not a dependent variable of load size. Reply Brief, PGP, R-PG-01, 23.

[page 108]

PGP also claims that BPA's methodology for determining Federal system hydro resources in the rate proceeding is inconsistent with the Coordination Agreement methodology for calculating the capability of the FBS, in that the rate filing methodology differs from the Coordination Agreement methodology in its treatment of the months of May. PGP argues that BPA is legally precluded from making this exception. Reply Brief, PGP, R-PG-01, 24.

PGP acknowledges that the Water Budget under the Columbia River Basin Fish and Wildlife Program has costs associated with it. It asserts that it is "improper to allocate the costs of the Water Budget only to FBS users." Reply Brief, PGP, R-PG-01, 25. PGP claims that section 7(g) of the Northwest Power Act requires that the costs of the Water Budget be borne by all BPA customers. Reply Brief, PGP, R-PG-01, 25.

Finally, PGP asserts that surplus firm power is generated in May because objective facts point to a greater availability of surplus firm power during May. It suggests that BPA should be attempting to sell a substantial amount of surplus firm power at that time. PGP points to the fact that BPA has made sales of surplus firm power in May in past years. Therefore, PGP concludes, some portion of costs should be allocated to surplus firm power in May. Reply Brief, PGP, R-PG-01, 25.

**Evaluation of Positions**

PGP claims that BPA's exclusion of excess hydro energy generation in May constitutes a load defined FBS. Reply Brief, PGP, R-PG-01, 23. There is no statement in PGP's brief that any definition of FBS size is partially determined by loads. The Coordination Agreement methodology for determining the capability of the hydro resources recognizes that those resources will be operated in a way which allows the hydro generation to follow loads in order that the hydro output may be shaped to serve firm loads. Any shaping assumption BPA could make of Federal hydro resources relates resource output to monthly loads. Therefore, in any period under study, the size of the FBS is determined, in part, by the expected monthly firm loads.

In order to minimize the effect of the shaping assumption on the size of the FBS in the test year, BPA adopted in the 1983 rate proceeding and in the 1985 rate proposal an assumption of shaping of the Federal hydro resources that levelizes the critical period hydro energy generation. BPA's intent in adopting this shaping assumption is to recognize the average hydro output of the critical period in the test year. BPA does not, however, have unfettered discretion in adopting a shaping assumption for the output of the Federal hydro system. In implementing the Water Budget, BPA has adopted a separate hydro shaping operation that is designed to aid in the downstream migration of fish. Under Water Budget operations, hydro operations are conducted so that water is stored in reservoirs, resulting in reduced hydro generation during eleven months of the year.

During May, the Water Budget calls for release of stored water to aid the migration of anadromous fish. This operation of the Federal hydro system is [page 109] one of the constraints used in preparing the hydro studies pursuant to the Coordination Agreement. The Water Budget causes large amounts of hydro generating capability to be shaped into May. The actual Water Budget operations shape power out of the period June 15 through April 15, and call for the release of such stored water during the period April 15th through June 15th. The power shaping under BPA's ratemaking treatment, that is, power reduced during 11 months of the year and increased in May, is a modeling assumption which approximates the actual Water Budget operations. Because the Water Budget is an actual physical constraint affecting the operation of the Federal hydro system, BPA cannot assume that power shaped into May by the Water Budget can subsequently be shaped out of May by a shaping assumption that levelizes the Federal hydro output for ratemaking purposes. Therefore, BPA levelizes the Federal hydro output over a 39-month period, and excludes May months into which the Water Budget has specifically shaped large amounts of hydro generation. Use of a levelized average hydro capability of the 39 months does not address the problem created by excessive generation capability present in May as a result of the Water Budget. In the initial proposal, the test year average firm surplus during the non-May months was 952 MW. During May, the firm surplus, as a result of the Water Budget, was 5840 MW. Such a surplus cannot be shaped out of May.

In addition to the large amount of firm surplus available in May, a substantial amount of nonfirm energy is also projected to be available during May. Power purchasers, both within and outside the region, are aware of the abundance of energy during May. It is reasonable to assume that those potential purchasers will elect to purchase power during May at the lower Nonfirm Energy rate rather than at the higher Surplus Firm Power rate.

PGP argues that BPA should use either a 42-month average (rather than a 39-month average) in levelizing hydro output during the critical period, or a 39-month average and recognize the entire firm capability of the Federal hydro system during May. Use of the 42-month average in levelizing the hydro output would ignore the Water Budget operations. Use of the 39-month average for levelizing the hydro system output and recognition of the full capability of the hydro system during May would ignore the fact that BPA cannot expect a surplus firm power load to materialize during May, and that BPA cannot reasonably expect to make surplus firm power sales during May. In all other months, resources are shaped in a levelized fashion for ratemaking purposes. During those non-May months. BPA can reasonably expect that with aggressive marketing efforts all or a portion of the available surplus firm power can be sold. BPA cannot reasonably make that same assumption about generation in excess of firm loads during May.

The PGP argument that the FBS size during May is determined by loads is inaccurate. BPA's assumption relating to FBS size during May recognizes both the effects of the Water Budget on the availability of the resources during May, and the overall availability and marketability of power (including nonfirm energy) during May. PGP urges BPA to assume a large surplus firm power load for cost allocation purposes during May because such an assumption increases the size of the FBS and thus spreads out the costs. If BPA were to
[page 110] adopt PGP's suggestion the size of the FBS would be determined by fictitious loads, based on an unwarranted assumption that such firm loads could materialize.

It is unclear whether PGP understands BPA’s view relating to the costs of the Water Budget. PGP believes that "it is improper to allocate the costs of the Water Budget only to FBS users."

Reply Brief, PGP, R-PG-01, 2 5. The cost of the Water Budget is a reduction in the size of the FBS. There are no further costs or monetary expenditures associated with the Water Budget.

PGP may mistakenly believe that the Water Budget is merely are shaping of Federal hydro resources out of eleven months of the year and into May. If the total of all firm loads during May corresponded with the availability of power during May, then the Water Budget would be simply a reshaping of hydro resources, and could be viewed as a costless measure. However, the availability of firm power far exceeds the projected loads during May. It can reasonably be assumed that water available during May will either spill over the dams or be used to generate power that will be sold at the nonfirm energy rate. It is therefore not reasonable to allocate costs to a surplus firm power load that has little possibility of materializing. PGP points out that BPA sold 48 MW at the Surplus Firm Power rate during May 1984. BPA had approximately 6000 MW of power available in excess of firm loads at that time. A sale of 48 MW of this total amount is insignificant, and is not guaranteed to recur.

The Water Budget itself is a fish and wildlife measure. BPA's hydro studies do not recognize the Water Budget as requiring BPA to incur opportunity costs in the marketability of surplus firm power in May. The shaping of hydro resources in the hydro studies subsume the effects of the shaping required by the Water Budget. In the ratemaking process, BPA's removal of excess generation (the assumption of no available surplus) during May gives specific recognition to the opportunity costs incurred by BPA resulting from its inability to sell the surplus firm power at the SP rate during May. This procedure reduces the size of the FBS and causes users of the FBS to bear the costs of the Water Budget. This methodology is consistent with BPA’s allocation of fish and wildlife costs for which funds are expended. *See* Section 3, *supra*.

**Decision**

*BPA excludes from the firm capability of the Federal hydro system generation during May that is in excess of that required to serve firm loads. This exclusion is a valid and appropriate method for determining the size of the FBS for the test year. It recognizes the availability of an exceptionally large amount of both firm and nonfirm energy during May. It would be inappropriate to include the excess firm energy in May in the FBS if it is spilled or sold as nonfirm energy. This method eliminates from the FBS some of the hydro generation shaped into May for purposes of meeting the Water Budget requirement, and allocates the nonmonetary costs incurred in*
[page 111] *implementing the Water Budget consistent with BPA's allocation of fish and wildlife costs.*

**Issue #2**

*What portion of the output of the Hanford generating project should be included in the Federal base system?*

**Summary of Positions**

BPA includes a net amount of energy equal to 72 percent of the output of the Hanford project as an FBS resource in its ratemaking load and resource balance. Revitch, BPA, E-BPA-27, 10.

PGP argues that both the Northwest Power Act and the preference customers' Power Sales Contracts require that 100 percent of the output of the Hanford project be recognized as an FBS resource in allocating exchange costs to the preference customers. Reply Brief, PGP, R-PG-01, 26.

**Evaluation of Positions**

Under the 1963 Hanford exchange agreements, five investor owned utilities and several participating publicly owned utilities exchange all of Hanford's power output for firm BPA power. By the terms of a 1974 letter agreement, BPA has committed an amount of power equal to 50 percent of Hanford's output (Hanford Extension Energy) to be available to five IOUs at the cost to the Washington Public Power Supply System of producing that power for the duration of Hanford's operations. Revitch, BPA, E-BPA-27, 10. For this reason, neither the IOUs' Hanford load, nor their share of the Hanford output, has been included in BPA's ratemaking load and resource balance; moreover, the costs of such power were not included in BPA's revenue requirement. See BPA, 1983 Rates ROD, 13-15.

Three of the five originally participating IOUs are no longer projected to take Hanford power in the current rate proceeding test year. A reallocation among the IOUs with the right to receive Hanford Extension Energy has left BPA with an obligation to deliver to each of the remaining two IOUs an amount of Hanford Extension Energy equal to 14 percent of Hanford's total projected output. Therefore, the total BPA obligation to the IOUs is equal to 28 percent of Hanford's projected output. The net amount of energy remaining after accounting for BPA's obligations pursuant to the 1974 letter agreement and related agreements, 72 percent, is available to BPA to serve its loads and is included in the FBS. Revitch, BPA, E-BPA-27, 10.

PGP argues that BPA's obligation to supply energy to the IOUs is independent of a contractual obligation to the preference customers to include 100 percent of Hanford output as an FBS resource. PGP claims that under the Hanford exchange agreements, the power BPA supplies to the IOUs is related to the agreements but it can be supplied by any BPA source of power; it does not
[page 112] depend entirely on the operation of Hanford. Pre-Hearing Brief, PGP, P-PG-01, 2-3. PGP does not suggest which specific BPA source of power either is or can be used to serve the IOU Hanford load, nor does it suggest a mechanism by which BPA can balance ratemaking loads and resources if 100 percent of Hanford were included in the FBS and the IOU Hanford load excluded from BPA's total loads.

PGP also claims that at the time of the passage of the Northwest Power Act, BPA had acquired 100 percent of Hanford. Therefore, PGP claims that under sections 3(10) and 7(b) of the Act, BPA must use 100 percent of Hanford (as an FBS resource) before allocating exchange costs to the preference customers. Reply Brief, PGP, R-PG-01, 27.

PGP further claims that the definition of "Federal base system resources" in section 7(c) of the Power Sales Contracts includes the full capability of Hanford. Therefore, claims PGP, BPA must recognize 100 percent of Hanford as an FBS resource.

PGP asserts that BPA did not commit 50 percent of the Hanford Project's output to the IOUs by the 1974 letter agreement. PGP claims that the letter agreement simply continued the existing Hanford exchange agreements while simply changing pricing provisions. PGP states that the essence of BPA's transaction regarding Hanford has been and is now an exchange.

The 1963 Hanford exchange agreements and the 1974 letter agreement both preceded the passage of the Northwest Power Act. BPA's obligation to provide an amount of power up to one half of Hanford's output to the IOUs was in place at the time of the passage of the Act. Neither the Act nor the Power Sales Contracts nullified BPA's obligation to provide Hanford power to the IOUs in an existing contract.

The 1974 letter agreement states: "…half the energy which becomes available due to the continued operation of the Hanford Project will be offered for purchase by the companies at the incremental cost of the supply system of continued operation." Letter Agreement, May 8, 1974, p. 2. The language of the agreement ties BPA's obligation to serve the IOU Hanford loads to output from Hanford. The effect of this provision is to reduce the net amount of energy available to serve other BPA loads. This contractual obligation is analogous to BPA's obligation to serve both United States Bureau of Reclamation (USBR) Reserve Power loads, and the Columbia River Storage Power Exchange (CSPE) loads with power output of the Federal Columbia River Power System. Agreements obligating BPA to serve these loads with FCRPS resources were also in place prior to the passage of the Northwest Power Act. For ratemaking purposes, these USBR and CSPE loads, which BPA is contractually obligated to serve, are excluded from BPA's ratemaking load and resource balance. The FCRPS resources used to serve such loads are also excluded from the firm capability of the FBS in BPA's ratemaking load and resource balance.

PGP's argument that BPA's obligation to supply Hanford energy to the IOUs is independent of BPA's contractual obligation to the preference customers to
 include 100 percent of Hanford as an FBS resource is also incorrect. BPA is not obligated by section 7(C) of the Power Sales Contracts to include 100 percent of Hanford's output in the FBS. Section 7(C) states only that, for purposes of restricting power deliveries pursuant to section 5(e) of the Northwest Power Act, the firm capability of the FBS *will be calculated from* the firm capability of the listed resources. It then lists three types of resources that contribute to the FBS: Federal hydro electric projects; resources available under long term contracts in effect at the time of the passage of the Act; and resources acquired to replace reductions in the firm capability of FBS resources. At the time of the passage of the Act, BPA was committed to deliver power to the IOUs by both the Hanford exchange agreements and the 1974 letter agreement. In the list of resources contained in section 7(C) of the Power Sales Contracts, Hanford's *installed* capability is listed at 860 MW. No indication is given that the installed capability is equivalent to Hanford's *firm* capability for FBS purposes. Further, nothing in the Power Sales Contracts limits BPA's treatment of Hanford costs for ratemaking purposes.

BPA's pre-Act obligation to deliver energy to the IOUs, pursuant to the 1974 letter agreement, is carried out by the 1983 Hanford Extension Agreement. Contract DE MS79-83BP90951. Because the energy must be delivered at its incremental cost of production, the obligation is not a load to which costs pursuant to section 7(g) of the Northwest Power Act or any other costs may be allocated. This fact is accounted for in the COSA by listing only a net amount of 72 percent of the Hanford output as are source. Such a listing in the COSA is consistent with the ratemaking treatment used for both USBR and CSPE obligations. The Supply System recovers the costs of Hanford operations for output obligated to the IOUs from the IOUs through rates established by the 1974 letter agreement. BPA therefore excludes both the IOU Hanford loads and that portion of power required to serve such loads from its ratemaking load and resource balance in order not to distort the cost allocation of FBS resources to users of the FBS.

Were BPA to include 100 percent of Hanford as an FBS resource, the preference rate would not change. This is because BPA would have to increase its load obligation by an amount equal to the increased FBS in order to account for the obligation to deliver an identical amount of energy to the IOUs. BPA cannot allocate costs to this IOU Hanford load because the 1974 letter agreement fixes the rate for this load. This load should properly be viewed as an FBS load under this alternative approach because it must be served in order to obtain a net amount of energy for the FBS equal to 72 percent of that produced by Hanford.

An argument could be made that the IOU Hanford load could be accounted for as a 7(f) load. This treatment would be tantamount to saying that BPA is serving the IOU Hanford load with resources costing more than BPA can recover under the terms of the 1974 letter agreement. Because the sole beneficiaries of treating Hanford costs in this manner would be the 7(b) customers, the unrecovered cost of serving the IOU Hanford load from higher cost resources should be allocated to the 7(b) pool. This treatment produces rates identical
[page 114] to those that result from including a net of 72 percent of Hanford resources in the FBS.

**Decision**

*BPA correctly lists 72 percent of Hanford's energy output, the net amount of energy available to BPA under the Hanford agreements, as an FBS resource for ratemaking purposes in the test year. BPA is obligated by agreements in effect at the time of passage of the Northwest Power Act to deliver an amount of energy equal to 28 percent of Hanford's energy output at the cost to those IOUs that are still entitled to such power under the Hanford agreements. The remaining 72 percent of Hanford's output is properly treated as an FBS resource in BPA's ratemaking load and resource balance.*

### 2. Conservation Costs

**Issue #1**

*Should the contract charge methodology be eliminated and conservation costs be recovered through BPA rates?*

## Summary of Positions

In the initial proposal, BPA allocated all conservation costs through rates based on the assumption that a cost sharing methodology would be implemented for determining BPA incentive payments for utilities with non-BPA loads. Ratchye, BPA, E-BPA-28, 8-9; Hickey, BPA, E-BPA-13, 10. An extension of the 1983 rate case methodology for the contract charge was offered as an alternative cost allocation method to be used if the cost sharing policy development was not completed before the end of the rate proceeding. Ratchye. BPA, E-BPA-29, 10; Ratchye, BPA, TR 3125-3126, TR 3132; Hickey, BPA, STR 129, TR 4078.

PGP advocates a cost sharing policy for utilities with non-BPA load in conjunction with recovery of BPA's conservation costs through rates, instead of the contract charge and partial recovery through rates. Fiddler, PGP, E-PG-12, 2, 10. PNGC and WPAG argue that BPA should continue to use the contract charge unless a particular type of cost sharing is adopted. Johnson, PNGC, E-PN-03, 2; Reply Brief, PNGC, R-PN-01, 3; Hutchison, et al., WPAG, E-WA-01, 50-53; E-WA-01S, 14-15. Additionally, PNGC argues that the cost sharing decision purports to allocate conservation costs under section 7(g) of the Northwest Power Act and should, therefore, have been part of the 7(i) rate adjustment proceeding. Initial Brief, PNGC, B-PN-01, 7.

## Evaluation of Positions

The cost sharing proposal and contract charge methodology are designed to address the recovery of conservation costs over non-BPA loads (loads served with resources other than those purchased from BPA). Ratchye, BPA, E-BPA-28, 6. At the time of the 1983 rate filing, BPA intended to fund conservation
[page 115] programs overall regional loads. *See* 1983 COSA, BPA, WP-83-FS-BPA-05, G-22. In the 1983 rate filing, since conservation benefits were accrued to all regional loads and not only to BPA load, a contract charge was used to allocate conservation costs to non-BPA loads; costs associated with BPA loads were recovered through BPA rates. Ratchye, BPA, E-BPA-28, 7.

Since the 1983 rate filing, some of BPA's assumptions for resource planning and acquisition have changed. BPA no longer intends to acquire conservation overall regional loads. Instead, BPA funding of conservation is limited to current signers of conservation contracts and those utilities that are eligible for conservation contracts because they have loads served by BPA. Hickey, BPA, E-BPA-13, 2-3. Moreover, BPA has limited the funding of conservation programs to loads served by BPA by adopting a cost sharing proposal. Cost sharing is the upfront sharing of the cost of conservation program incentives between BPA and the conservation program implementor. Hickey, BPA, E-BPA-13, 10. The result of implementing a cost sharing proposal is that conservation costs associated with non-BPA loads are eliminated from BPA's revenue requirement. Ratchye, BPA, E-BPA-28, 9; Hickey, BPA, TR 4085. The cost sharing proposal was developed and adopted in a separate public involvement process held concurrently with the rate proceeding. Hickey, BPA, E-BPA-13, 10; E-BPA-13S, 7.

PNGC and WPAG do not criticize the general philosophy that cost sharing in conjunction with recovery of conservation costs through BPA rates is an appropriate alternative to the contract charge. Instead, they take issue with the type of cost sharing methodology that was adopted in the separate proceeding. Both parties maintain that conservation cost recovery through rates is in equitable unless cost sharing directly proportional to a utility's non-BPA load had been adopted in that proceeding. Hutchison, et al., WPAG, E-WA-01, 50; E-WA-01S, 14; Johnson, PNGC, E-PN-03, 2, 6; Initial Brief, PNGC, B-PN-01, 5. BPA described in cross-examination how the results of the cost sharing proceeding allow for equitable recovery of conservation costs through rates. The change in program eligiblity [sic] and the adoption of cost sharing for utilities with non-BPA load ensure that BPA funds conservation only on BPA loads. Hickey, BPA, TR 4085. Since BPA is no longer acquiring conservation from non-BPA loads, a nonrate mechanism like the contract charge is no longer required for equitable cost recovery. The amount of cost sharing that is required to ensure that BPA receives all the conservation it pays for was a topic in the cost sharing proceeding and not a subject for the 1985 rate proceeding. Melton, TR 3145-3146; *see* Final Conservation Cost-Sharing Principles, January 21, 1985; *see also* O-29.

The cost sharing proceeding did not undertake, as PNGC claims, the allocation of BPA conservation costs to power rates that is described in section 7(g) of the Northwest Power Act. The cost sharing policy development process determined which conservation costs would be funded by BPA. Program funding decisions are normally made outside the rate proceeding, and the costs are then incorporated into the revenue requirement to be allocated in the rate proceeding. Another example of this procedure is the decision on the restart of Supply System plants, which was made in a public process and the dollar
[page 116] effects then incorporated in the rate proceeding. See BPA Review of Washington Public Power Supply System Projects 1 and 3 (WNP-1 and -3) Construction Schedule and Financing Assumptions, November 1, 1984. Similarly, the cost sharing policy development process determined what portion of a utility's conservation costs would be eligible for funding by BPA. BPA's portion of the costs is then incorporated into BPA's revenue requirement.

**Decision**

*All costs of BPA-funded conservation programs are recovered through BPA rates. The cost sharing policy was adopted by the Administrator on January 21, 1985. Issues related to conservation cost recovery over non-BPA loads are resolved through the funding mechanism for conservation incentive payments rather than by means of a contract charge.*

**Issue #2**

*What method should be used to allocate the conservation revenue requirement among rates?*

**Summary of Positions**

In the initial proposal, all conservation costs were allocated to loads served by Federal resources (FBS and new resource pools). The exchange resource pool includes some costs of the conservation that is not funded by BPA. Therefore, loads served by exchange resources are already indirectly allocated conservation costs. Ratchye, BPA, E-BPA-28, 8-10. PNGC and WPAG argue that all loads, including loads served by exchange resources, should be allocated conservation costs. Johnson, PNGC, E-PN-03, 6-8. Reply Brief, WPAG, R-WA-01, 27. The ICP argues that Surplus Firm Energy and Surplus Firm Power rates should be allocated conservation costs. Kellerman, ICP, E-IC-06, 11. SCE argues that conservation costs should be allocated to surplus firm power rates only if surplus firm power rates do not include the cost of the exchange resource pool. Hull, SCE, E-CE-03R, V-1; Reply Brief, SCE, R-CE-01, 35.

**Evaluation of Positions**

PNGC and WPAG maintain that conservation costs should be allocated to loads served by exchange resources because the new average system cost (ASC) methodology provides that fewer conservation costs are now allowed in computing a utility's ASC. Since the conservation costs passed through the exchange are negligible, exchange loads should be allocated BPA conservation costs. Johnson, PNGC, E-PN-03, 7-8, Reply Brief, WPAG, R-WA-01, 27. In addition, PNGC notes that in the 1983 rate filing, BPA argued that it was not appropriate to allocate conservation costs directly to the DSIs because the DSIs were not receiving funding for conservation during the rate period. PNGC and WPAG point out that the DSIs will receive conservation funding in the test year for this rate filing. Johnson, PNGC, E-PN-03, 6-7; Reply Brief, WPAG, R-WA-01, 28.

[page 117]

In the 1983 rate proceeding, one step of the conservation cost allocation process was based on participant benefits. When participant benefits are the basis for cost allocation, the identification of the loads receiving conservation funding in the test year is relevant. In the 1985 rate proceeding, participant benefits are no longer the basis for cost allocation. Therefore the fact that DSI loads receive conservation funding in the test year is not pertinent to the allocation of conservation costs to loads served by the exchange resource pool. The relevant issue is the amount of non-BPA funded conservation costs included in the exchange resource pool.

Conservation costs enter the exchange resource pool in two ways: the first is through utility sponsored conservation programs. The new ASC methodology includes fewer conservation costs for utility sponsored programs than the previous ASC methodology. Second, ASC includes payments made by generating utilities that participate in BPA-sponsored conservation programs. In the 1983 rate filing, the conservation contract charge paid by generating utilities was an exchangeable cost. In the 1985 rate filing, a cost sharing methodology has been substituted for the contract charge. Adoption of the cost sharing methodology results in fewer conservation costs being exchanged because the cost share amount is less than the contract charge. Therefore, PNGC is correct that fewer conservation costs are included in the cost of the exchange resource pool than in the previous rate filing.

The ICP argues that conservation funding contributes to increased availability of surplus firm power and that utilities purchasing surplus firm energy and capacity are the major beneficiaries of conservation acquired during the surplus period. The ICP considers that BPA's "perceived difficulties in the marketability of surplus firm power" are "an inappropriate reason for not associating appropriate costs with the appropriate products benefiting from those costs." Kellerman, ICP, E-IC-06, 11. Therefore, ICP proposes a formula based on conservation benefits to allocate a portion of the cost of new conservation to the Surplus Firm Power rates. The rationale behind the formula is that new conservation frees up firm generation resources. Therefore, the ICP recommends that a pro rata share of BPA's conservation revenue requirement be substituted for the top increment of generation costs contributing to the Surplus Firm Power rate. Kellerman, ICP, E-IC-06, 10-12. However, BPA is projecting the sale of only three quarters of the projected surplus firm power at the cost-based SP-85 rate. The rest is projected to be sold in the nonfirm energy market. Concentrating a portion of the conservation costs directly on the Surplus Firm power rates will aggravate this revenue underrecovery situation.

SCE agrees with ICP that it is appropriate to allocate conservation costs to surplus power rates because these rate classes benefit from conservation. However, SCE argues that an allocation of conservation costs to surplus power rates is appropriate only if exchange resource pool costs are not allocated to surplus rates. Hull, SCE, E-CE-03R, V-1; Reply Brief, SCE, R-CE-01, 34-35. SCE maintains that a double allocation of conservation costs will occur if surplus rates are allocated BPA conservation costs in addition to the conservation costs included in the exchange resource pool. Reply Brief, SCE, R-CE-01, 34-35. SCE has not quantified the amount of double counting of
[page 118] conservation costs that could occur, nor did SCE argue against PNGC's point that it is now appropriate to allocate BPA conservation costs to loads served by exchange resources because the non-BPA sponsored conservation costs included in the exchange resource pool are diminished from the last rate proceeding.

**Decision**

*Conservation costs are allocated to all loads. It is now appropriate to allocate BPA conservation costs to loads served by exchange resources because fewer conservation costs are included in the exchange resource pool as a result of the new ASC methodology and the cost sharing policy. This allocation does not concentrate conservation costs on the surplus firm power and energy rates, thereby adversely affecting the marketability of surplus firm power. Instead, the pro rata allocation results in an allocation of an equitable share of conservation costs to the surplus firm power and energy rates.*

### 3. Fish and Wildlife Costs

**Issue #1**

*How should BPA's fish and wildlife costs be allocated?*

**Summary of Positions**

BPA allocates fish and wildlife costs only to firm power customers receiving an allocation of the costs of FBS resources. BPA, E-BPA-01, 46. These costs are directly related to the Federal hydro system. Costs incurred to mitigate the damage to fish and wildlife caused by Federal dams on the Columbia River should be charged only to the beneficiaries of those dams, not to all BPA customers.

PPC proposes that BPA's fish and wildlife program costs be allocated to all rates. Wolverton and O'Meara, PPC, E-PP-02, 1. PPC claims that all BPA customers benefit from the existence of the Federal Columbia River Power System. PPC also asserts that preservation of fish and wildlife is a general good, and that nearly everyone in the region benefits. Wolverton and O'Meara, PPC, E-PP-02, 1-2. PPC argues that its allocation proposal is consistent with BPA's allocation of fish and wildlife costs in 1981. Wolverton and O'Meara, PPC, B-PP-01, 50.

PGP maintains that the reduction in the capability of the FBS, resulting from implementation of the Water Budget under the Columbia River Basin Fish and Wildlife Program, is a fish and wildlife cost. Therefore, all customers of BPA benefit from the Water Budget and, under section 7(g) of the Northwest Power Act, these costs should be spread to all customers of BPA. Initial Brief, PGP, B-PG-01, 31-32.

[page 119]

**Evaluation of Positions**

The FCRPS hydro electric projects are defined in the Northwest Power Act as FBS resources (16 U.S.C. §839a(10)). Section 7(g) instructs the Administrator to "equitably allocate in accordance with generally accepted ratemaking principles, and provisions of this Act," all costs and benefits not otherwise allocated by the Northwest Power Act, including fish and wildlife measures. Section 7(g) does not specifically direct an allocation of costs to all customers. Section 7(b)(1) directs the Administrator to allocate costs of FBS resources first to Priority Firm power customers.

Fish and wildlife costs are incurred by BPA to mitigate the adverse effects the Federal hydro system has on anadromous fish. Palensky, BPA, E-BPA-15, 3. Fish and wildlife costs include both the expenditure of funds for mitigating damage done to fish populations, and costs incurred by BPA in adopting specific operations of the Federal hydro system to aid downstream migration of fish, such as the Water Budget. Such expenditures are an internalization of society's costs associated with the hydro electric facilities. These costs are much like the costs a utility incurs at a coal-fired generating facility to internalize the atmospheric pollution costs the facility would impose on society in the absence of pollution control devices. It is standard practice in the electric utility industry to allocate the costs of pollution control devices only to those power purchasers who buy power from that facility. BPA, 1983 Rates ROD, 164.

BPA acknowledges that in the 1981 Record of Decision, the Administrator allocated fish and wildlife costs to all power users. 1981 Rates ROD, Decision VI-19. In that year, however, when the Northwest Power Act was in its nascent stage, BPA anticipated that at least a portion of the expense associated with fish and wildlife may be directed toward programs which are unrelated to the effects of hydro plants. Id. Moreover, the Record of Decision continued, "[a]s the programs for which these expenses are incurred become better defined, it may be possible to develop a more disaggregated allocation of these costs for future rate filings." Id.

In both the 1983 and the 1985 BPA rate filings, BPA has been able to identify the specific purposes of the fish and wildlife expenditures. Those costs should be allocated to the customers that are the assured beneficiaries of the Federal hydro system. The Water Budget, although involving no cash expenditures, is a component part of these costs in that it is a fish and wildlife measure that reduces the capability of the FBS specifically for the purpose of aiding the downstream migration of young anadromous fish. BPA, 1983 Rates ROD, 164.

**Decision**

*Fish and wildlife expenditures, including the Water Budget, are confined to mitigating the effects on fish and wildlife caused by hydro electric facilities on the Columbia River and its tributaries. Therefore, all fish and*
[page 120] *wildlife costs in the test period are allocated to firm power purchasers that are allocated the costs of FBS resources.*

**4. Depreciation Expense**

**Issue #1**

*Should depreciation expense be omitted from the COSA?*

**Summary of Positions**

In the COSA, BPA divides its revenue requirement between annual costs and the Net Repayment Requirement (NRR). Depreciation expense is included in the annual costs, and subtracted from interest and amortization, to determine the NRR. BPA, E-BPA-01, 15-16. Depreciation expense is identified with generation and transmission plant on the basis of the gross investment in the facilities. The NRR is associated with the plant on the basis of the investment base for the facilities. The depreciation expense and NRR are apportioned differently among the customer classes.

The ICP proposes omitting the adjustment for depreciation expense for the following reasons: it makes no difference in the total revenue requirement; it complicates the rate process for no apparent reason; and it is not documented in the record. The ICP also proposes distributing the total interest and amortization among the transmission segments on the basis of the NRR. McCullough, ICP, E-IC-02, 1-3; Initial Brief, ICP, B-IC-01, 14; Reply Brief, ICP, R-IC-01, 12-15.

**Evaluation of Positions**

BPA’s revenue requirement is determined in accordance with the U.S. Department of Energy's repayment policy. The revenue requirement includes annual obligations and interest and amortization for the Federal investment in the FCRPS. Depreciation expense is not a determinant of the revenue requirement. However, BPA's COSA is presented in accordance with generally accepted utility ratemaking practice. Annual operating expenses plus are turn equal the total revenue requirement. Annual operating expenses include depreciation expense. For BPA, the return is the Net Repayment Requirement, which is total interest, amortization and investment service coverage less depreciation expense. This is the same as total revenue requirement less annual operating expenses.

In addition to presenting the cost of service (total revenue requirement) in accord with general utility practice, it also is appropriate to recognize depreciation expense, even though it has no effect on BPA’s total revenue requirement, because the depreciation expense and the return (NRR) are identified with facilities and apportioned among customer classes in different

ways. Depreciation expense is appropriately identified with facilities on the basis of gross plant investment. In accord with general utility practice, the
[page 121] return (NRR) is distributed among the facilities, e.g., transmission system segments, on the basis of the investment base for the facilities. The investment base is the average net plant investment. Net plant investment is the gross plant investment less accumulated depreciation.

Because the recognition of depreciation is in accord with general utility practice, it does not complicate the rate process for no apparent reason. The ICP proposal to segment the total interest and amortization on the basis of the NRR would not simplify the rate process. The depreciation expense must be computed to determine the investment base, which is the basis for the distribution of the NRR.

The ICP assertion that COSA Tables 1 through 5, and the depreciation expense, were not documented is erroneous. It is true that a narrative description of each line and column entry in these tables was not prepared. However, documentation for the COSA does include the computation of depreciation expense for the initial proposal. BPA, E-BPA-01A, Chapters VI and VII. In the final proposal the computation is revised to include the audited financial data for FY 1984.

**Decision**

*Depreciation expense is not omitted from the COSA. It is in accord with general utility practice to include depreciation expense in annual costs and to apportion depreciation expense among facilities, including transmission segments, and among customer classes, differently than the distribution of NRR.*

**5. Transmission Costs**

**Issue #1**

*What method should be used to develop coincidence factors for the Southern Intertie?*

**Summary of Positions**

BPA developed a single coincidence factor for Federal and non-Federal nonfirm deliveries because of expected changes in the pattern of Intertie use due to the new Intertie Access Policy. Revitch, BPA, E-BPA-27, 19.

The ICP argues that a single monthly coincidence factor for all nonfirm service on the Southern Intertie, one that does not distinguish between Federal nonfirm and non-Federal nonfirm, is inappropriate. Wilson, PP&L, E-IC-09, 6-8.

**Evaluation of Positions**

The ICP recommends that coincidence factors for allocating costs on the Southern Intertie be separately determined for Federal nonfirm energy sales, [page 122] and for non-Federal nonfirm energy wheeled by BPA, using data for the period FY 1980-FY 1983. Also, it recommends that coincidence factors used for allocating costs under the 12 CP methodology, for all surplus firm power sold at nonfirm rates on the Southern Intertie, should be coincidence factors used for allocating costs to Federal nonfirm energy sales utilizing the Southern Intertie. Initial Brief, ICP, B-IC-01, 19.

The ICP argues that if individual coincidence factors for Federal and non-Federal use of the Intertie had been developed, a marked difference between the two components would be shown. The range of Federal nonfirm monthly coincidence factors during the FY 1981-FY 1983 period far surpasses that of the non-Federal nonfirm factors. Wilson, PP&L, E-IC-09, 6-8. Moreover, ICP contends that while both services are "nonfirm," one service involves the sale and transmission of Federal energy and the other service involves the wheeling of non-Federal energy. Wilson, PP&L, E-IC-09, 9-10. The ICP further argues that although access to the Intertie will change as a result of the new Intertie Access Policy, patterns of use will not change dramatically from the past. Therefore BPA should wait until there has been actual experience under the new policy and make adjustments, if any, in the next rate case. Wilson, PP&L, E-IC-09, 8, 9.

Historically there has been an inverse relation between Federal and non-Federal use of the Southern Intertie. BPA usually charged the Spill rate when the Intertie was loaded. This caused non-Federal customers to displace thermal generation (IOUs) or BPA purchases (generating public utilities). With elimination of the Spill rate, the ICP argues, thermal resources should be modeled as generating and being sold. Wilson, ICP, E-IC-09S, 7. PGP states that its members will not displace purchases when the NF rate is greater than the PF energy charge. Spettel, PGP, E-PG-07S, 2. Thus, even the ICP recognizes that the pattern of Intertie use by both Federal and non-Federal customers will change. Consequently, a single coincidence factor was developed for both Federal and non-Federal deliveries over the Intertie to account for Intertie scheduling under the IAP. Revitch, BPA, E-BPA-27, 19.

The combination of Federal and non-Federal nonfirm energy loads is an attempt on BPA's part to model equal access to the Southern Intertie by both types of power. The coincidental peak allocation depends on both the coincidence factor and forecasted nonfirm energy sales. Energy forecasts still incorporate the individual capability of Federal and non-Federal utilities to sell nonfirm energy. Revitch, BPA, E-BPA-58R, 6, 7.

The adoption of a uniform intertie adder is consistent with the development of melded coincidence factors. In order to reach a uniform mills per kilowatt adder for is and NF sales, these two classes must be combined for the purpose of allocating Intertie costs.

**Decision**

*The coincidence factor calculation for all nonfirm energy utilizing the Pacific Southwest Intertie takes into account the use that is reasonably*
[page 123] *expected to occur under the Intertie Access Policy. It will more accurately allocate costs between Federal and non-Federal service under expected conditions. Therefore, BPA's method for developing coincidence factors for the Southern Intertie is appropriate. For*

*discussion on the uniform charge that is to be implemented for uses of the Southern Intertie, see Chapter IX, Section H. The ICP's acceptance of a uniform 1.2 mills per kilowatt hour charge (Reply Brief, ICP, R-IC-01, 25) renders moot ICP's concerns over a combined coincidence factor.*

**Issue #2**

*What methodology should be used to allocate transmission costs to the Southern Intertie?*

**Summary of Positions**

BPA measures use of the transmission system in terms of the average of twelve monthly coincidental peak loads placed on the segments by each customer class. This measurement indicates class contribution to the relevant system peak used to determine the need for additional investment in transmission system capability. Therefore, coincidental peak load is a measurement of use closely related to cost causation. Revitch, BPA, E-BPA-27, 16.

SCE feels that use of July's single monthly CP demand would be more appropriate for allocation of transmission costs. Hull, SCE, E-CE-01A, V-4, V-5.

**Evaluation of Positions**

Consistent with BPA's measurement of use of other transmission segments, 12 CP loads are used to identify relative use of the Southern Intertie segment. Revitch, BPA, E-BPA-27, 17. The hour of coincidental peak and associated coincidence factors for loads using the Intertie are measured with respect to the peak load on this segment rather than to loads placed on the transmission system as a whole. Revitch, BPA, E-BPA-01, 33.

SCE argues that it is important to realize that the projected monthly peak demands on the Intertie range from a low in September to a high in July, but it is the system peak demand that influences the size and cost of the facilities and should be used to allocate costs. During July, SCE finds that the non-Federal nonfirm peak demand was 25.9 percent of the July peak demand for the Intertie. The 25.9 percent allocation therefore would be more representative of cost causation and cost responsibility for the Intertie; applying that allocation factor to Southern Intertie transmission costs would result in a scaled down revenue requirement. Hull, SCE, E-CE-01A, V-4, V-5.

Use of a single month (July) as a basis for allocating costs of the Southern Intertie would not take into account the cost causation of that segment of BPA's transmission system. The Intertie was not built for use
[page 124] during only one month or one season. Transmission costs are not seasonally differentiated and energy transmission is required year-round. Therefore, transmission allocation factors should incorporate the need for year-round service. Revitch, BPA, E-BPA-58R, 1, 2.

**Decision**

*The 12 CP allocation method is appropriate for determining the coincidental peak demand for purposes of allocating transmission costs to the Southern Intertie. A 12 CP allocation factor for transmission service takes into account the need to ascribe costs on the basis of both peak usage and annual energy usage.*

**Issue #3**

*How should non-Federal nonfirm wheeling over the Southern Intertie be forecast for cost allocation?*

**Summary of Positions**

In the initial proposal BPA used projections from the NFRAP for forecasts of total non-Federal nonfirm wheeling on the Southern Intertie. Chang, BPA, E-BPA-42, 12. However, transmission rate calculation requires customers specific projections of incidental wheeling to forecast sales subject to firm and nonfirm rates. Total NFRAP projections were distributed among BPA's wheeling customers according to their purchases of incidental wheeling during FY 1983. In addition to the customer distribution of NFRAP forecasts, the projections were separated between direct bilaterals to the PSW and sales made under the Exportable Agreement based on historical data.

The initial proposal remained unchanged in the supplemental testimony except for the NFRAP reduction in projected non-Federal sales. NFRAP still provided total projected non-Federal sales by all customers to the PSW. Chang, BPA, E-BPA-42S, 2. In rebuttal testimony, BPA proposed that all incidental wheeling projections, intra- and extraregional, be based on historical sales. Southwest obligation returns of peak replacement energy from the PNW and Canada were proposed to be included in the development of the IS and IN rates. Chang, BPA, E-BPA-59R, 2.

The ICP recommends that BPA use the NFRAP for all purposes and should not selectively use historical figures for non-Federal nonfirm power wheeled on the Southern Intertie. Initial Brief, ICP, B-IC-01, 20. ICP argues that the revised NFRAP assumption of is sales is not justified and drives up IS-85 costs. ICP also contends that BPA overlooked potential PSW sales from PNW thermal plants that were projected by BPA to be shut down by regional displacement. Correcting this error, the ICP claims, would increase is sales. Wilson, PP&L, E-IC-09S, 6-8.
[page 125]
LADWP also contends that forecasted sales are too low, but agrees with the costs BPA allocated to the IS-85 rate. Parmesano and Whitney, LADWP, E-LA-01, 18, 19, 22.

**Evaluation of Positions**

The NFRAP results relied on in BPA's supplemental proposal showed a reduction in projected non-Federal sales due to increased displacement of non-Federal Northwest resources. Because of this reduction, BPA proposed in rebuttal testimony to use FY 82-FY 84 historical averages of IS and ET-2 (exportable) sales as a projection for FY 1987. Chang, BPA, E-BPA-59R, 2. Both IS and IN were, then, consistently based on historical results, and the monthly distribution of the FY 82-FY 84 averages could reasonably be applied to the coincidence factors developed from FY 80-FY 83 historical data on both Federal and non-Federal sales. As with the initial and supplemental proposals, allocated Southern Intertie costs are spread over forecasted bilaterals to the Southwest. In addition, forecasted obligation return energy is included in the is rate calculation. These adjustments lowered the is rate in rebuttal testimony. Chang, BPA, E-BPA-59R, 2; TR 1219. NFRAP has been revised for the final study and shows PNW thermal plants are available for PSW sales. For further discussion on NFRAP, see Chapter VIII, Section I. With the above changes incorporated into NFRAP and with the resulting NFRAP output compared to historical sales, NFRAP now produces reasonable estimates for Southern Intertie wheeling.

The ICP claims that use of historical non-Federal nonfirm sales for FY 82-FY 84 for one purpose and use of projected loads derived in part from the NFRAP for other purposes creates a mismatch in the COSA cost allocation methodology. Historical figures for FY 82-FY 84 cannot be used for non-Federal nonfirm energy sales without altering the monthly levels of Federal nonfirm sales. Thus, while historical figures for non-Federal nonfirm energy wheeled by BPA on the Southern Intertie can be used for purposes of transmission rate design, the ICP maintains that NFRAP should be used exclusively for allocating costs in the COSA between classes of service on the Southern Intertie. NFRAP should be used for determining Federal nonfirm sales and non-Federal nonfirm sales for purposes of cost allocation under the 12 CP methodology in the COSA. Initial Brief, ICP, B-IC-01, 20, 21.

Since Federal and non-Federal uses of the Southern Intertie are interrelated, it is desirable to use an integrated model to forecast IS, as was done in the initial and supplemental BPA proposals. Chang, BPA, E-BPA-42S, 3. NFRAP was revised in the rebuttal testimony to model the sale of non-Federal nonfirm energy to California utilities at BPA's Standard Nonfirm energy rate, and then to displace PNW baseload thermal resources. Additionally, NFRAP now contains different modeling for daytime and nighttime hours. These revisions increased the FY 87 total California market; thus NFRAP forecasts of overall sales to the PSW are now similar to their historical levels. Roghair, BPA, E-BPA-66R, 4-7.



**Decision**

*NFRAP is used to forecast non-Federal nonfirm wheeling over the Southern Intertie for transmission cost allocation. The appropriate Southern Intertie wheeling projections for cost allocation purposes are derived from NFRAP (E-BPA-66R). which considers the availability of PNW thermal plants. For further discussion on NFRAP, see Chapter VIII, Section I.*

**Issue #4**

*Are quality of service differences between Federal and non-Federal users of the FCRTS recognized in the COSA?*

**Summary of Positions**

The COSA is the principle mechanism used to allocate costs equitably between Federal and non-Federal power utilizing the FCRTS. Chang, BPA, E-BPA-42, 16. In the allocation process, Federal and non-Federal power are considered comparable on a megawatt for megawatt basis. Metcalf, BPA, TR 4217.

PSP&L argues that an equitable allocation of FCRTS costs between Federal and non-Federal power must take into account the subordinate nature of transmission service for non-Federal users and the different, and in many cases onerous, terms and conditions that govern service for non-Federal users relative to Federal users. Pre-Hearing Brief, PSP&L, P-PS-01, 8.

**Evaluation of Positions**

PSP&L mentions, as an example of the subordinate nature of wheeled power, the General Transmission Rate Schedule Provisions (Section 11) which state, in effect, that any capacity in the FCRTS that BPA determines to be in excess of required capacity to transmit Federal obligations will be made available to all utilities. Morris, PSP&L, TR 4212. BPA applies that section when evaluating a utility request for a wheeling agreement. Once a utility has signed a wheeling agreement, power wheeled under that agreement has access to the FCRTS equal to the access enjoyed by Federal power. Silverstein, BPA, TR 4213.

PSP&L suggests that through individual wheeling contracts BPA provides one way wheeling service, whereas Federal customers receive two way service. Initial Brief, PSP&L, B-PS-01, 9. PSP&L does not, however, provide any evidence for its contention that Federal customers receive two way service. However, some FPT wheeling contracts do provide two way service to non-Federal customers. Chang, BPA, TR 4214.

PSP&L also appears to claim that BPA limits designated points of delivery (POD). Morris, PSP&L, TR 4214. BPA has limited firm wheeling points of delivery based on loads served at those points. This limit is not unlike limits placed on power sales customers. It is BPA's normal practice to decide
[page 127] mutually with the customer on a set of points of delivery and points of integration based on the service required. Silverstein, BPA, TR 4214.

PSP&L notes that wheeling rate billing factors include an 11 month demand ratchet. Morris, PSP&L, TR 4215. PSP&L further argues that BPA did not take the demand ratchet into account in setting its proposed wheeling rates. Reply Brief, PSP&L, R-PS-01, 5. A demand ratchet is not unique to wheeling agreements, however; several wholesale power rate schedules also contain such clauses; e.g., the NR and PF rates for power sales to computed requirements customers, and the CF rate. Chang, BPA, TR 4215; Metcalf, BPA, TR 4222. It should also be noted that the 12 CP method of developing allocators for wheeling customers provides recognition of those months when wheeling customers' peak use is less than their contract demand. The 12 CP allocators are then applied in the COSA to all projected firm wheeling demands. Wheeling customers are not, as claimed, subjected to a discriminatory billing factor through the 11 month demand ratchet.

**Decision**

*There are no differences in the quality of service provided to Federal and non-Federal users of the FCRTS that have not properly been addressed in the cost allocation process. PSP&L has provided no evidence to substantiate its claim that non-Federal customers are governed by different terms and conditions than Federal customers. The COSA equitably allocates the FCRTS cost between Federal and non-Federal users. Granting of points of integration and points of delivery for both Federal and non-Federal users of the FCRTS will continue to be mutually agreed upon as a part of the contract negotiations process.*

[page 129]

# VI. SECTION 7(c)(2) INDUSTRIAL MARGIN STUDY

## A. Introduction

The Northwest Power Act provides that beginning July 1, 1985, the rates that apply to BPA's DSI customers shall be equitable in relation to the retail rates charged by public body and cooperative customers to their retail industrial consumers. Section 7(c)(2) requires that the rate be based on BPA’s applicable wholesale rates to public body and cooperative customers, plus a margin typical of that included by these customers in their retail rates to industrial consumers. Section 7(c)(2) also specifies that the DSI rate shall take into account size and character of load, relative costs of capacity, energy, transmission, and delivery facilities, and direct and indirect overhead costs, all as related to delivery of power to industrial customers.

The section 7(c)(2) Industrial Margin Study describes the calculation of the "typical margin." It quantifies adjustments to the margin, consistent with the directives of section 7(c)(2). The margin resulting from this study is added to the applicable Priority Firm Power rate to develop the Industrial Firm Power rate.

## B. Data Base Used to Calculate Unadjusted Margin

**Issue**

*What source of data should be used for calculating the margin?*

**Summary of Positions**

BPA's data base is derived from financial and operating reports submitted to BPA by its public body and cooperative customers; from the annual reports of such customers; and from responses by the customers to BPA data requests. Carr and Taves, BPA, E-BPA-47, 4, 5.

The DSIs believe that the BPA data base does not contain critical data. They argue that the BPA data base includes non industrial and extremely small industrial consumers, which are not representative of industries comparable to the DSIs, and that BPA includes utilities that have no industrial load. The DSIs also contend that BPA’s data base cannot be used to compute the actual industrial margins included in utilities' retail industrial rates. Schoenbeck, DSI, E-DS-12SR, 6-10. The DSIs developed an alternative data base which includes 13 utilities serving 26 industrial customers with peakloads of at least 3.5 megawatts. The DSI data base contains revenue, rate, and cost [page 130] information for firm service industrial consumers of retail utilities. Schoenbeck, DSI, E-DS-02, 12-16. The DSIs and NWU later in the proceeding jointly sponsored a data base consisting of 19 public utilities, including those utilities in the original DSI sample. Hager and Saleba, NWU, and Schoenbeck, DSI, E-NU/DS-01R, 1-4.

WUTC contends that the DSI data base is too small to reflect accurately the margins in the industrial rates of preference utilities. The sample of utilities and industrial accounts is too limited to be termed representative of all industrial load. Rolseth, WUTC, E-NU-01R, 3. APAC also argues that the DSIs' data sample is too small and that if data for industrial consumers can be identified, they should be included in the study, regardless of the size of the load. Cook, APAC, TR 2820-2821. APAC supports the adoption of the joint DSI/NWU data base. Initial Brief, APAC, B-PA-01, 56 (n. 71).

**Evaluation of Positions**

The joint data base and the DSIs' data base include the majority of loads in the region above 3.5 megawatts peak demand. They also provide peak and energy amounts for each industrial consumer, thereby allowing direct power cost allocation. Hager, et al, NWU, NU/DS-01R, 2; Schoenbeck, DSI, E-05-12SR, 2-3, Schedule 2-15. BPA's data base, by contrast, does not limit the size of industrial consumers. One of the major shortcomings of BPA's data base, according to NWU, is that it does not allow identification of the number of consumers or the sizes of individual loads. Oral Argument, NWU, TR 4989-4990.

The DSIs argue that the data base used in determining the industrial margin must be comprised of retail industrial customers that are comparable in size to the DSIs. Schoenbeck, DSI, E-DS-02, 10. However, section 7(c)(2) does not delimit industrial size, but requires that size and character of load will be taken into account when determining the section 7(c)(2) rate. The language does not indicate where in the process size and character of load should be evaluated. APAC supports the view that industry size is not a governing factor for the choice of a data base, but should be considered after the margin is developed. Cook, APAC, TR 2820-2821.

The DSIs urge that load factor be a consideration used in selecting the sample group. Schoenbeck, DSI, E-DS-02, 18. Again, section 7(c)(2) does not delimit the size or character of industrial loads to be used in the analysis. Instead, it allows for adjustments for these factors to be considered in determining the rate.

The DSI data base, which contains information about only 13 preference utilities, is too limited in scope in light of the joint data base, which has the same quality of data for an additional six utilities.

The joint DSI/NWU data base offers significant advantages. The joint data base provides data necessary to compute average power costs to retail industrial consumers. Hager and Saleba, NWU, and Schoenbeck, DSI, E-NU/DS-01R, 1-4. In addition, the cost of service analyses that support the [page 131] joint data base provide cost allocations to industrial rates, thereby allowing detailed disaggregation of margin components. Hager, et al, E-NU/DS-01R, 3. Such a disaggregation allows individual treatment of each component and makes the development of the margin more straightforward.

**Decision**

*Use of the joint DSI/NWU data base allows flexibility and enhances objective analysis. Direct allocation of costs to customers is standard ratemaking practice. The jointly-sponsored data base is built on the conceptual approach of disaggregating costs charged to retail industrial customers for the purpose of determining utility industrial margins. Therefore, BPA uses the data contained in the DSI/NWU data base to determine the industrial margin. The DSI data base, which disaggregates costs in a similar fashion, contains too few utilities and retail industrial consumers to use to determine a margin typical of that employed by preference utilities in their industrial rates.*

## C. Applicable Wholesale Rate

**Issue**

*How should the applicable wholesale rate be determined?*

**Summary of Positions**

In its initial margin study, BPA used a preliminary determination of the average cost of BPA wholesale power to all public agencies as the "applicable wholesale rate" specified in section 7(c)(2). Carr and Taves, BPA, E-BPA-46, 4. BPA then added its proposed margin to this amount to derive the margin-based DSI rate. Carr and Taves, BPA, E-BPA-47, 12; Carr and Taves, BPA, E-BPA-47, 12; Carr, BPA, TR 2603, 2621-2622.

NWU agrees with the BPA initial proposal. NWU believes that the applicable wholesale rate should be derived by applying the PF-85 rate charges to billing determinants of the Priority Firm customer class as a whole. Lessner, et al., NWU, E-NU-9R, 20; Reply Brief, NWU, R-NU-01, 11-12. APAC agrees with NWU that the applicable wholesale rate is the average PF-85 rate to public agencies. Initial Brief, APAC, B-PA-01, 51; Reply Brief, APAC, R-PA-01, 19-21.

The DSIs assert that the applicable wholesale rate is the rate level that results from applying the PF-85 rate to DSI billing determinants. The DSIs argue that the computation of the "applicable wholesale rate" should recognize the effect of DSI load factors on rate level. This effect would be ignored if Priority Firm class billing determinants were used instead of DSI billing determinants. Schoenbeck, DSI, E-DS-02, 507; Schoenbeck, DSI, TR 2758. The DSIs also disagree with BPA's use of a preliminary PF-85 rate. They contend [page 132] that the applicable wholesale rate computation should be based on the final PF-85 rate charges. Schoenbeck, DSI, E-DS-02, 21-23; Schoenbeck, DSI, E-DS-12SR, 20; Initial Brief, DSI, B-DS-01, 20-21.

The DSIs argue that the NWU proposal mismatches the power cost of the preference customers with a margin based on the retail industrial class. This mismatching artificially raises the section 7(c)(2) rate over the comparable industrial rate. Schoenbeck, DSI, E-DS-12SR, 18-20.

**Evaluation of Positions**

Resolution of this issue hinges on the determination of whether industrial load characteristics should be reflected in the calculation of the "applicable wholesale rate" as well as in the computation of the section 7(c)(2) "typical margin." The DSIs argue that industrial load characteristics should be reflected in both determinations; the other parties claim that it should be factored into only the margin.

In general, retail industrial power rates are developed based on the load characteristics of retail industrial consumers, rather than the load characteristics of the utility's entire system. To do otherwise would violate sound ratemaking principles by subsidizing non industrial, low load factor customers at the expense of the industrial customers. The joint data base empirically demonstrates that retail ratemaking typically bases each customer class's power costs on that class's character of load. Load characteristics have a large effect on the wholesale generation and transmission costs that go into calculating the total cost of service to industrial consumers.

The most straightforward reading of section 7(c)(2)(B) leads to the conclusion to use the DSI billing determinants. In determining an equitable DSI rate, BPA must take into account the relative capacity, energy and transmission costs of delivering power to "industrial customers." This can be done only in calculating the "applicable wholesale rate." Generation and transmission costs are largely irrelevant to the margin calculation, which relates primarily to distribution costs.

The term "equitable" has been discussed extensively by APAC. APAC defines "equitable" as meaning "fair" and asserts that, based on their interpretation of the language of 7(c)(2), the average PF-85 rate is a "fair" rate to charge the DSIs. Reply Brief, APAC, R-PA-01, 19. APAC considers the terms "equitable" and "fair" to be synonomous [sic] in this instance. However, dictionaries also define "equitable" as "impartial." *New College Edition -- American Heritage Dictionary*, 443 (1976). In determining the applicable wholesale rate to apply to the DSIs, the Administrator should develop the average wholesale rate to the DSIs in the same manner as average rates are developed for preference customers and other buyers of wholesale power, i.e., by applying billing charges to the approximate billing units. Such an impartial approach appropriately provides the benefits of a high load factor to customer(s) that place such a load on BPA.

[page 133]

NWU argues that the 7(c)(2) language would have been different if Congress had intended for BPA to develop the applicable wholesale rate in the manner proposed by the DSIs. NWU claims that the phrase "wholesale rates to such public bodies and cooperatives as applied to the DSIs" would have been used rather than "applicable wholesale rates to such public body and cooperative customers." Reply Brief, NWU, R-NU-01, 13. NWU also claims that no evidence on the record shows that retail industrial consumers' wholesale rate component is based on the BPA rate at the specific consumer's load factor. Reply Brief, NWU, R-NU-01, 12. However, the data base co-sponsored by NWU and the DSIs essentially allocates power costs to retail industrial consumers in that fashion.

NWU and APAC note that the DSIs advocated use of an average wholesale rate at the time of the hearings on the Northwest Power Act. Initial Brief, APAC, B-PA-01, 53-54; Reply Brief, NWU, R-NU-01, 12-13. This is evidence of the DSIs' expectations, but not necessarily of congressional intent. Inasmuch as the DSIs' statements are self-serving (or, as it turns out in this case, nonself-serving), it is the technical arguments that tip the balance in favor of applying PF rate charges to DSI billing determinants. These arguments, set out below, incoporate [sic] standard utility ratemaking principles in allocating power costs to customer classes.

The major cause of differences between overall average utility power costs and average industrial power costs is in the coincidence, or contribution, of system peak demand of the industrial consumer in relation to that of other utility customers. NWU recognizes the effects of coincident peaking by assigning as a margin component the additional demand charges collected from a particular industrial consumer by its serving utility, which did not have a "time-of-day" pricing structure. Lessner, et al., NWU/DSI, E-NU/DS-01R, Attachment 11. In effect, the production cost of this utility to serve its industrial load was the wholesale power rate applied to the customer billing determinants. In fact, in most instances, the joint NWU/DSI data base determines wholesale power costs by applying PF rate charges to industrial billing determinants. Therefore, using the appropriate billing factors to determine wholesale power costs is demonstrated by the joint data base supported by NWU.

The Northwest Power Act requires that the DSI rate be equitable compared to retail industrial rates charged by publicly owned utilities in the region. If the margin were combined with the average Priority Firm rate, the resulting rate would be greater than an "equitable rate" because industrial consumers typically have higher load factors than utility systems as a whole. For purchasers of wholesale power, higher monthly load factors lead to lower average power costs. Adding the margin to wholesale power costs based on industrial load characteristics is consistent with the Northwest Power Act's requirement that the DSI rate be equitable in relation to retail industrial rates. Symmetrical with determination of the margin, the factors in section 7(c)(2)(A), (B), and (C) must be taken into account in the development of the "applicable wholesale rate."
[page 134]

BPA agrees with the DSIs that the factors to be considered in section 7(c )(2)(A), (B), and (C) of the Northwest Power Act are pertinent to both the margin determination and the applicable wholesale rate determination. BPA considers the factors in the margin calculation by using the joint DSI/NWU data base. Basing the applicable wholesale rate on the DSI billing determinants assures that the same factors are considered in the power cost component of the DSI rate.

BPA recognizes that the applicable wholesale rate computation should be based on final PF-85 rates (prior to any 7(b)(2), DSI floor rate or scaling adjustments) rather than on a preliminary PF-85 rate as BPA initially proposed. BPA expressed some uncertainty during cross-examination about whether it had the computer programming capability to develop a final PF rate prior to developing the IP rate. Carr, BPA, TR 2553-2555. BPA subsequently reevaluated the situation and finds that the two rates can be developed simultaneously.

**Decision**

*The parties advocating the use of the average PF-85 rate have not shown that such an approach is consistent with common practice in utility rate setting efforts. They have also not provided convincing arguments that the power cost determination approach for retail industrial consumers should differ from the approach used for determining the DSIs' applicable wholesale rate. Therefore, BPA develops the applicable wholesale rate by applying forecasted DSI monthly demand and energy amounts to the PF-85 rate as calculated before adjusting for 7(b)(2), DSI floor rate, and scaling. The margin added to this rate will help ensure that the DSI rate is equitable in relation to retail industrial rates.*

**D. Cost Components to be Included in Margin**

**Issue # 1**

*Should non-BPA funded conservation costs be considered a component of the margin?*

**Summary of Positions**

In the initial proposal, BPA implicitly considered conservation, generation, and transmission costs to be power supply costs and therefore excluded them from the margin. Carr and Taves, BPA, E-BPA-47, 11-12; Carr and Taves, BPA, E-BPA-02AA, Item 7.

The DSIs support BPA's exclusion of conservation costs. The DSIs argue that all conservation costs should be considered as power production costs because their purpose is to reduce the amount of generating resources that will have to be acquired to serve load. Schoenbeck, DSI, E-DS-12SR, 5; Carter, DSI, TR 2790.

[page 135]

NWU contends that there are two types of conservation expenses. The first type includes expenses incurred to acquire resources; these expenses should be considered power supply costs and excluded from the margin. The second type includes customer service costs, such as advertising, miscellaneous overhead and customer information; these costs should not be excluded from the margin because they are not directly related to resource acquisition. NWU considers costs funded by BPA conservation programs to be related to resource acquisition. NWU contends that conservation costs not funded by BPA are customer service costs. NWU proposes a method for estimating the portion of conservation costs directly related to resource acquisition for utilities that have not signed BPA conservation contracts. Lessner, et al., NWU, E-NU-9R, 16-17; E-NU-11SR, 5.

**Evaluation of Positions**

The DSIs argue that conservation costs should be treated similarly to costs incurred in building a generation facility. Administrative and general costs associated with the construction of a generating unit are capitalized and assigned to the cost of that resource. The DSIs contend that it is therefore appropriate to assign similar conservation costs to generation. Carter, DSI, TR 2790.

NWU maintains that the only direct costs of the conservation measures are those related to resource acquisition. Hutchison, NWU, TR 2662. NWU doubts that there is a clear link between expenditures for advertising or customer information about conservation and the actual acquisition of the conservation resource. Hutchison, NWU, TR 2656-2657; TR 2661-2662.

During cross-examination, there was considerable debate about whether non-BPA funded conservation costs could be exchanged for Priority Firm power under BPA's revised methodology for determining the average system cost (ASC) of a utility's resources. The discussion focused on the utility used as a proxy by NWU to functionalize conservation costs of utilities that had not signed BPA conservation contracts. The DSIs asked NWU if this utility, by applying to exchange some of its non-BPA funded conservation costs with BPA, had claimed that the costs were production-related. NWU agreed that the utility had made that claim, but pointed out that the average system cost methodology allows only direct costs of the conservation measures to be exchanged, and disallows those costs not necessary to save the actual energy. Hutchison, NWU, TR 2660-2662.

It is difficult to determine the extent to which utility-funded conservation activities, including advertising and customer information, lead to the acquisition of conservation resources. However, it would not be appropriate to include identifiable non-BPA funded conservation expenditures related to nonacquisition in the power cost component.

**Decision**

*Conservation costs not associated with direct acquisition of a resource or energy savings and not reimbursed by BPA are included as a margin component.*
[page 136] *BPA follows this principle only where the data allow disaggregation of conservation costs between non-BPA funded direct acquisition and promotion activities.*

**Issue #2**

*Should a portion of transmission costs be included in the margin?*

**Summary of Positions**

In its initial methodology, BPA excluded all transmission costs from the margin, believing that power supply and transmission costs are not typical margin components. Carr and Taves, BPA, E-BPA-47, 11-12. The DSIs agree. They claim that all transmission costs should be treated as production-related because all transmission contributes to generation-integration. They contend that in BPA's revised ASC methodology, BPA permits utilities to exchange all transmission costs for power at the Priority Firm Power rate. Schoenbeck, DSI, E-DS-12SR, 4.

NWU maintains that not all transmission costs are related to generation-integration. It asserts that high-voltage transmission required to transfer power within a distribution system is distribution-related and should be included in the margin. Full requirements customers do not generally own any significant generation resources, so all transmission costs of full requirements customers are distribution-related. A portion of reported transmission expenses of generating publics should be treated as power cost if the costs are generation-related. For generating utilities that do not separately identify generation-integration costs, transmission costs other than wheeling should be allocated between power supply cost and margin, based on plant investment in generation-integration versus other transmission plant. Lessner, et al., NWU, E-NU-9R, 11-15. NWU claims that classification of transmission costs according to actual use of the facilities is consistent with DSI use of the cost causation principle in analyzing other costs. Lessner, et al., NWU, E-NU-11SR, 5.

**Evaluation of Positions**

The transmission system functions are integrated such that it is difficult to segregate those functions relating to generation-integration from those relating to distribution. NWU acknowledges that voltage level criteria alone are not sufficient to segregate generation-integration transmission facilities from those that perform a distribution function. Lessner, et al., NWU, E-NU-9R, 13-14. NWU admits that some generating utilities do not separately identify generation-integration costs from other transmission costs. NWU therefore had to develop a method for approximating these costs. Lessner, et al., NWU, E-NU-9R, 14-15.

The DSIs underscore the difficulty of segregating transmission costs by pointing out that during BPA's average system cost reconsultation, utilities
[page 137] argued that all transmission costs should be exchangeable with BPA because there is no valid basis on which to distinguish transmission generation-integration costs from other transmission costs. Schoenbeck, DSI, E-DS-12SR, 4.

The impacts on the margin of incorporating the approximation method proposed by NWU are more substantial than not including any transmission components. Without a more substantive basis for delineating between generation-integration and high-voltage distribution, no transmission costs can be justified for inclusion in the margin.

**Decision**

*Transmission costs are assigned to production and are not included in the margin. The evidence on the record does not demonstrate that the disaggregation of transmission costs between generation-integration and high voltage distribution could be accomplished with a high degree of qualitative success.*

**Issue #3**

*Should revenue taxes be a component of the margin?*

**Summary of Positions**

BPA includes revenue taxes in the margin. BPA considers all taxes other than property taxes to be related entirely to the utility’s distribution function because such taxes are based on the sale, rather than the production, of electric power. Carr and Taves, BPA, E-BPA-47, 9. NWU supports this position. Lessner, et al., NWU, E-NWU-11SR, 3.

The DSIs, in contrast, assert that revenue taxes represent a governmental revenue collection device rather than a cost incurred by a utility in providing electric service. The DSIs suggest that such taxes are not typical of all BPA preference utility customers, because the taxes are assessed only on utilities operating in Washington and in certain Oregon cities. The DSIs further argue that, because revenue taxes are not included in BPA's revenue requirement, the inclusion of these taxes in the margin would constitute a windfall rate reduction to other customers. Schoenbeck, DSI, E-DS-02, 17.

**Evaluation of Positions**

NWU considers the DSI argument that revenue taxes are a governmental collection device in valid because public utility payments for BPA power ultimately are sent to the U.S. Treasury. Lessner, et al., NWU, E-NU-9R, 9. NWU also believes that the DSIs' exclusion of revenue taxes is inconsistent with the DSI's general assumption that the margin analysis should be performed as if the DSIs were served at the retail level by public agencies. Lessner, et al., NWU, E-NU-9R, 9. In addition, NWU rebuts the DSIs' claim that revenue taxes should be excluded because they are not paid in all jurisdictions. NWU
[page 138] maintains that this approach would exclude from the margin any cost that appears in some, but not all, public utility industrial rates and therefore would result in calculation of "typical costs included in industrial rates," rather than the "typical margin." Furthermore, NWU discounts the DSI claim that inclusion of revenue taxes would result in a windfall to other customers. The DSI rate is to be based on typical margins without regard to whether comparable costs are included in BPA’s wholesale rate. Lessner, et al., NWU, E-NU-9R, 7-11; Lessner, et al., NWU, E-NU-11SR, 3, 4.

The DSIs’ argument that revenue taxes are not a cost incurred by the utility in providing electric service is convincingly refuted by NWU. NWU maintains that revenue taxes are clearly a cost of doing business because a utility cannot conduct its business without paying the taxes to which it is subject. Because the taxes are based on the sale rather than the production of electric power, a utility would pay no revenue taxes if it did not generate any revenue from providing service to its customers. Lessner, et al., NWU, E-NU-9R, 8. This simply makes such taxes a variable cost instead of a fixed cost. NWU also effectively refutes the DSI position that revenue taxes should be ignored because they are not levied in all jurisdictions. The fact that not all utilities incur revenue taxes is no more a basis for a blanket exclusion from the margin than would be the exclusion of any other cost not incurred by each and every public agency in the region. Lessner, et al., NWU, E-NU-11SR, 4; Lessner, et al., NWU, E-NU-9R, 9-10. Furthermore, the DSIs do not uniformly apply this theory of excluding all costs which do not appear in all rates. NWU cites, as an example, the fact that not all utilities in the DSI data base include distribution costs in the margin. Lessner, et al., NWU, E-NU-9R, 10. NWU also discounts the DSI claim that if revenue taxes were included in the margin, BPA would have to provide a windfall rate reduction to all other customers because BPA does not incur comparable cost in serving the DSIs. This argument is contrary to the premise that the margin is to be based on the typical margin included in the retail industrial rates of public utilities. Lessner, et al., NWU, E-NU-9R, 11.

The DSIs express concern that utilities collecting revenue-based taxes may be subject to abuse by the tax-levying body, especially municipally owned and/or operated utilities. The DSIs are concerned that municipalities may try to shift the taxes levied in their jurisdiction from property taxes or similar assessments to the utility in the form of revenue taxes. Reply Brief, DSI, R-DS-01, 19. This would, through the margin derivation methodology, result in a subsidy from the DSIs to local municipal governments by means of a lower PF rate. Ratepayers would essentially be unharmed, with higher utility bills being offset by lower direct tax burdens.

This argument is unconvincing. First, presupposing such an action by the municipalities is based on speculation, not factual evidence, and therefore is not a rationale for excluding revenue taxes from the margin. Second, municipally owned or operated utilities are subject to General Contract Provision (GCP) 47 of their power sales contract with BPA, which reads in part:

[page 139]

> …(4) Payments made into a governmental entity general fund via taxes or payments in lieu of taxes. The percentage of gross electric revenues used for this purpose shall be an amount not exceeding the greater of the following:
>
> (i) an amount which is equal to five percent of the gross electric revenues, unless a greater amount is provided pursuant to the city charter or agreements in effect as of December 5, 1980; or
>
> (ii) the amount of State or local taxes levied upon the Purchaser's electric system or its operations.

If a municipally owned or operated utility is currently paying the maximum amount allowable under GCP 47 to the city general fund, any attempt to increase that amount places the utility in violation of its power sales contract with BPA.

**Decision**

*Revenue taxes are a cost incurred by a utility in distributing power and therefore are included in the margin. The record fails to provide a compelling reason for not considering revenue taxes as a cost of doing business.*

**Issue #4**

*Should legal expenses related to generation resources be included in the margin as administrative and general expenses?*

**Summary of Positions**

BPA functionalized all administrative and general expenses from its own data base prorata to generation, transmission, and distribution on the basis of functionalization of other operating expenses excluding purchased power. Carr and Taves, BPA, E-BPA-47, 8.

Legal expenses relating to litigation over Washington Public Power Supply System facilities and fees in connection with the 7(k) proceeding were identified for one utility in the NWU/DSI data base. The DSIs contend that these are power cost expenses which should not be included in the margin. Schoenbeck, DSI, E-DS-12SR, 5. NWU includes these expenses in the margin calculation. Hager, et al., E-NU/DS-01, 3.

**Evaluation of Positions and Decision**

The DSIs' argument in opposition to the inclusion of legal costs relating to power production in the margin are persuasive. These expenses were incurred for the sole purpose of reducing power expenses. Furthermore, these [page 140] expenses can be exchanged as production expenses under the Average System Cost Methodology (ASCM). Schoenbeck, DSI, E-DS-12SR, 5. Legal costs associated with terminated plant, however are not exchangeable under the ASCM. NWU failed to show how these costs are related in any way to margins charged retail industrial consumers. Therefore, these legal costs are not included in the margin calculation.

**E. Weighting of the Margin**

**Issue #1**

*What is the proper method for weighting individual utility margins to calculate the "typical" margin?*

**Summary of Positions**

BPA calculated the "typical" margin by deriving margins for each utility in the study sample and weighting them according to the amount of each utility's industrial sales. BPA, E-BPA-46, 4. The weighting of individual margins by energy sales prevents disproportionate influence on the typical margin by small segments of the retail industrial sector. Carr and Taves, BPA, E-BPA-47, 13. The DSIs agree that industrial margins should be weighted by energy sales. Schoenbeck, DSI, E-DS-10R, 6, 7.

NWU suggests that the "typical" margin should be calculated by weighting the margins by the number of industrial customers served by each utility in the study. NWU claims that the method used by BPA and the DSIs produces the margin paid on the typical kilowatt hour, not the typical margin paid by retail industrial customers. Lessner, et al., NWU, E-NU-11SR, 6; Lessner, et al., NWU, E-NU-9R, 18.

**Evaluation of Positions and Decision**

Weighting individual utility margins by number of customers would give disproportionate weight to utilities serving small loads. Moreover, as the DSIs point out, if the margin is to be assessed on a per kilowatt hour basis, then a per kilowatt hour cost is the proper measure of the margin. Schoenbeck, DSI, E-DS-12SR, 17. Common weighting techniques generally give weight to a factor based on its proportionate share of a total amount. NWU does not demonstrate that section 7(c)(2) require; (or even allows) a different weighting technique. Therefore, each utility's margin is weighted according to the utility's industrial energy sales.
[page 141]

**F. Adjustments to the Margin**

## 1. Inflation Adjustment

**Issue #1**

*What inflation factor should be used to escalate industrial margins to the test year?*

**Summary of Positions**

BPA uses historical and forecasted GNP implicit price deflators to escalate the calculated historical margin to FY 1987. Carr and Taves, BPA, E-BPA-47, 2-3.

The DSIs use GNP deflators for those utilities in which the margin calculation was based upon a cost of service study for a test year other than FY 1987. However, they argue that those margins to industrial consumers purchasing under rate schedules, as opposed to contract purchasers, should be inflated using labor cost indices. The DSIs believe that the typical margin will escalate more slowly than the general rate of inflation. Schoenbeck, DSI, E-DS-02, 19-20.

APAC asserts that the use of GNP deflator series for all of the margin costs is inappropriate. APAC agrees with the DSIs that contractually specified margins should be used. APAC supports the use of the GNP deflators only for there sold purchased power component of the margin, and recommends the use of the Handy-Whitman or a similar index for the remainder of margin costs. Cook, APAC, E-PA-09R, 4-5.

**Evaluation of Positions and Decision**

The GNP price deflator is a widely used inflation index, and is appropriate to use under circumstances where a myriad of costs exists and no other source of inflation estimates provides wide-ranging cost indices. Lessner, et al., NWU, E-NU-08, 12. BPA uses price deflators in many studies not directly associated with the rate process. Use of the Handy-Whitman indices, as advocated by APAC, does not address the components of the margin unrelated to construction. The DSIs' use of GNP price deflators to inflate industrial margins not governed by contract indicate at least tacit support.

The GNP price deflators are an appropriate mechanism to inflate the industrial margins. Use of more detailed indices, such as Handy-Whitman, is not warranted due to the limited nature of their application. Therefore, BPA uses GNP price deflators to increase the margin from the relevant utility test year to the BPA test period.

[page 142]

**Issue #2**

*What is the appropriate method for inflating margins to retail industrial consumers whose rates are contractually based on the cost of BPA power?*

**Summary of Positions**

BPA did not originally incorporate the margins specified in contracts to retail industrial consumers. BPA testified that such treatment is inconsistent with its initial methodology in which the IP-85 rate is developed based on the average PF-85 rate plus a margin. Carr and Taves, BPA, E-BPA-47, 11-12; Carr, BPA, TR 2701-2702.

The DSIs argue that contracts under which major industrial consumers purchase power either contain no escalators or contain margins that are tied to the production cost component of the contract rates. The DSIs point out that BPA indicates that its rates, which are the relevant production costs, will decline in real terms. Schoenbeck, DSI, E-DS-02, 20.

**Evaluation of Positions**

Contractually derived margins for retail industrial customer loads could have significant impact on the overall weighted margin. Margins based on a percentage of the wholesale cost of power will change differently than the rate of inflation if power cost increases differ. The DSIs claim that it is inappropriate to ignore contract margins because to do so would over state the test period margin, based on the data used in the study, as well as ignore business arrangements between the utilities and their industrial consumers. Schoenbeck, DSI, E-DSI-02, 20.

The DSIs subsequently claim that to use contractually specified margins exposes them to the risk in future rate cases of utilities redefining the source of power in those contracts under which retail industrial customers are served. The result could be a much larger industrial margin for the utility with no rate impact on the industrial customer. Reply Brief, DSI, R-DS-01, 7-8.

The position of the DSIs on the issue of using contractually-specified industrial margins is unclear. Throughout the proceedings, the DSIs lobbied for BPA to adopt contract margins in determining the typical margin. BPA was persuaded that contract margins should be recognized. The latest DSI argument on this issue appears to conflict with their earlier position. The arguments they put forth on this issue in their reply brief are speculative, contradictory, and without foundation, and therefore cannot be considered in determining the margin derivation methodology.

**Decision**

*The initial BPA methodology, by its nature, did not distinguish between contract margins and average margins for industrial consumers. With the* [page 143] *adoption of the joint DSI/NWU data base, it is now possible to inflate contract margins in the manner intended. BPA is convinced that, where possible, actual business arrangements should be recognized. As a result of the arguments in favor of doing so, BPA inflates contract margins using the factors specified in the retail industrial contracts.*

**2. Size and Character of Load Adjustments**

**Issue #1**

*Should the margin be adjusted for load factor differences between the DSIs and retail industrial consumers?*

**Summary of Positions**

BPA's character of load adjustment took into account load factor differences between the DSIs and retail industrial customers included in the BPA data base. BPA, E-BPA-46, 12. BPA did not take a position on whether a load factor adjustment to a margin computed from the NWU/DSI data base would be appropriate.

The DSIs propose a load factor adjustment for the portion of the margin accounted for by "other costs" (miscellaneous costs). The DSIs assert that these costs are allocated to consumers based either on demands placed on a utility's system or on the number of customers served. The DSIs argue that with increased load factors, these costs would be spread out over a larger number of kilowatthours, resulting in lower "other costs" per unit sold. The DSIs propose to apply the utilities classified margin costs identified as "other costs" to billing units of a 98 percent load factor class of customer to accomplish the adjustment. Schoenbeck, DSI, E-DS-12SR, 11-13.

NWU opposes a load factor adjustment. NWU argues that since the joint data base used to derive the margin is composed of retail industrial customers comparable in size to the DSIs, an adjustment for character of load is inappropriate. Lessner, et al., NWU, E-NU-11SR, 8-9. NWU asserts that "the Administrator should take into account relative cost characteristics of retail industrial and retail non-industrial loads. Using a data base that includes no non-industrial loads negates the need for any adjustment." NWU also cites the "volatile nature" of DSI loads in opposition to any downward. adjustment to the margin for character of load adjustment. Initial Brief, NWU, B-NU-01, 38-39.

APAC opposes an adjustment to the margin for load factor differences. While the average monthly load factors for the DSIs are high, in recent years the DSI annual load factors have been relatively low. Cook and Shanker, APAC, E-PA-02, 21-22; Initial Brief, APAC, B-PA-01, 58-59. The ICP opposes a downward adjustment for similar reasons. It cites the swing nature of DSI loads, contending that such loads can be more costly to serve than are more reliable loads. McCullough, ICP, E-IC-10, 3-7.

[page 144]

**Evaluation of Positions**

The DSIs did not adjust the margin computed from their original data base to take into account load factor differences between DSI and retail industrial loads. They stated that such an adjustment was unnecessary because the retail industrial consumers in their study sample were comparable to the DSIs from a cost standpoint. Schoenbeck, DSI, E-DS-02, 17-18. The DSIs do propose a load factor adjustment to the "other cost" component of the margin when using the joint data base, which includes six additional utilities and twenty-three additional industrial loads. Schoenbeck, DSI, E-DS-12SR, 13-15, Attachment 20. The DSIs derived a load factor adjustment of 12 mills per kilowatt hour by applying classified margin costs from the joint data base to billing determinants of a 98 percent load factor customer. Schoenbeck, DSI, E-DA-12SR, Schedule 1.

NWU argues that a load factor adjustment is not appropriate if the data base used to compute the margin is comprised of retail industrial consumers comparable in size to the DSIs. Lessner, et al., NWU, E-NU-11SR, 8-9. To make an adjustment based on monthly load factor is not appropriate due to the "swing" nature of the DSIs. The annual load factor of "swing" operations will undoubtedly be lower than plants operated as baseload facilities. To make an adjustment for monthly load factors would double count the character of load; BPA has already taken character of load into consideration by adopting the joint data base. Reply Brief, NWU, R-NU-01, 16.

While the DSIs use a comparison of average monthly DSI load factors and retail industrial load factors to support a downward adjustment to the margin, APAC demonstrates a need to recognize the effect of annual load factor on margin costs. APAC points out that annual load factors of the DSIs in recent years have been much lower than the average of their monthly load factors. Cook and Shanker, APAC, E-PA-02, 21. APAC also cites testimony by BPA supporting BPA's assertion that DSI aluminum smelters will continue to be swing plants characterized by low annual load factors. Cook, APAC, E-PA-09R, 5-7. As APAC notes, BPA must be ready to serve the DSIs at a level based on their annual peak operating levels; therefore, annual load factors are the appropriate measure of relative costs being incurred to serve a load. Initial Brief, APAC, B-PA-01, 59.

The DSIs argue that monthly load factors do affect the margin. They claim that lower monthly load factors significantly increase retail industrial margins, based on the data used in the study. Reply Brief, DSI, R-DS-01, 21-24. However, the record does not demonstrate how margins are affected by monthly load factors. The DSIs have only made generalized statements regarding utility practices to support their position. On the other hand, it can be argued that annual load factors should be utilized if a load factor adjustment is to be incorporated, based on a more straightforward rationale.

A utility provides capacity to a customer based on absolute peak demand requirements, not monthly load factors or average monthly load factors. The cost of providing capacity is almost exclusively an annual fixed cost to the
[page 145] utility and does not vary with the amount of loading on the facilities. As BPA stated in cross-examination: "The *per unit* delivery facility cost would be higher … with the lower load factor" (emphasis added). Carr, BPA, TR 2564. As the DSIs themselves state, if fixed costs are spread over fewer units of product, the per unit cost of the product increases. Reply Brief, DSI, R-DS-01, 22. Load factors do not address units (kilowatt hours) of product, per se, and monthly load factors are not guaranteed to account for the same number of kilowatt hours each month. If the DSIs reduce their operating level, then the per unit cost to BPA to provide facilities to the DSIs will increase, even if monthly load factors do not change. Logically, then, monthly load factors should not be used to allocate an annual cost because the magnitude of the load (the number of units of product) may vary significantly by month even though the load factor may not change by month. Consequently, annual load factors are more important to consider when allocating annual costs than monthly load factors.

The decision to adjust the margin for load factor considerations requires that sufficient evidence of the need to make an adjustment exists or has been demonstrated. Neither of these conditions has been met. The DSIs have not presented persuasive evidence nor have they crafted a convincing argument that monthly load factors are commonly used by utilities to allocate costs for setting retail industrial rates.  On the contrary, the use of annual load factors is a more intuitive and logically consistent approach to use for this purpose.  Other evidence presented leads to the conclusion that annual load factors for the DSIs are not likely to be superior to the retail industrial consumers used in the study.  If the DSIs, especially the aluminum companies, are relegated to swing plant status, they should not be expected to maintain high annual load factors as well as high monthly load factors.

**Decision**

*An adjustment to the margin for average monthly load factor considerations is not warranted. The DSIs realize the benefits of high monthly load factors in the determination of the applicable wholesale rate.  The evidence presented does not empirically relate costs included in utility margins to monthly load factors.  The effects of annual load factors should be recognized when evaluating utility costs included in industrial margins.  The record does not indicate that annual load factors for the DSIs are expected to differ substantially from annual load factors for the retail industrial consumers.  On these grounds, BPA concludes that a character of load adjustment based on monthly load factors is not justified.*

**Issue #2**

*Is an adjustment to the margin for "size of load" appropriate?*

**Summary of Positions**

BPA did not initially include an adjustment for size of load because load size does not create a significant cost difference between service to the DSIs
[page 146] and to retail industrial consumers.  BPA held that although several of the DSIs have loads that are greater in size than those of retail industrial consumers in the region, some are smaller.  Carr and Taves, BPA, E-BPA-47, 16, 25.

The DSIs assert that the industrial consumers in their original data base are comparable to the DSIs in terms of size.  Thus, no further adjustment would be necessary.  Schoenbeck, DSI, E-DS-02, 17-18.  However, the DSIs incorporate a size adjustment to account for the addition of six utilities in the NWU/DSI joint data base, since those utilities (which were not included in the DSIs' original data base) serve a number of small industrial consumers and substantially impact the weighted distribution cost component of the margin.  The DSIs recommend that the cost of the delivery facilities used by BPA to serve the DSIs be substituted for the distribution cost allocated by the preference utilities to their industrial customers.  Schoenbeck, DSI, E-DS-12SR, 12-14.

NWU believes that no additional adjustment needs to be made to the margin to account for the difference in load size of the DSIs and retail industrial consumers.  Lessner, et al., NWU, E-NU-08, 14.  NWU maintains that the same criteria used to establish the original DSI data base were used in selecting the additional six utilities for the joint data base; therefore, there is a level of comparability in size between the two data bases.  Lessner, et al., NWU, E-NU-11SR, 9, 10.

**Evaluation of Positions**

The differences in costs to serve large versus small loads is central to the issue of adjusting the margin to account for size differentials between the DSIs and retail industrial consumers. The DSIs maintain that there is a clear inverse relationship between size of load and margin. This is due primarily to costs of delivery facilities. A smaller customer, receiving service at secondary distribution voltage, would have certain distribution costs included in the margin, whereas a customer that receives service at transmission or primary distribution voltage would not have distribution costs allocated to its margin. Schoenbeck, DSI, E-DS-12SR, 11.

In their direct case, the DSIs argued that no adjustment had to be made to the margin to account for differences in size of loads. Schoenbeck, DSI, E-DS-02, 17. Since the loads used in their study were comparable in size to the DSI loads, no adjustment was necessary. Schoenbeck, DSI, E-DS-02, 18. However, in surrebuttal, the DSIs claim that a size adjustment is appropriate if the jointly sponsored NWU/DSI data base is adopted. This could be accomplished by substituting the cost of DSI delivery facilities for the comparable facilities included in the margin of the utility sample. Schoenbeck, DSI, E-DS-12SR, 13. The weighted distribution costs derived from the DSIs' initial sample of 13 utilities and 26 industrial consumers versus the joint data base including 6 additional utilities and 23 industrial consumers is markedly different. The additional 23 industrial consumers are, on average, less than one sixth the size (32.8 aMW vs. 6.0 aMW) of the average
 industrial consumer in the initial DSI data base, and have a weighted distribution cost over five times as large (2.83 mills vs. 0.55 mills). This result empirically demonstrates that the size of a load impacts the margins. Reply Brief, DSI, R-DS-01, 22-23.

The record indicates that some of the retail industrial customers in the sample are served over secondary voltage systems, i.e., distribution facilities. Schoenbeck, DSI, E-DS-12SR, 11. Whether delivery facilities are of transmission voltage or distribution voltage is immaterial when defining their purpose, which in this case is to provide service to industrial consumers. Delivery facilities provided by utilities to serve their retail industrial consumers are analogous to delivery facilities provided by BPA to serve the DSIs. Reply Brief, DSI, R-DS-01, 25. The issue here is the relationship of the size of the load to the cost of providing those delivery facilities. The DSIs have effectively demonstrated that consumers served over distribution facilities are more costly to serve on a mills per kilowatthour basis than are consumers that are served over transmission facilities, due primarily to the fact that consumers served over distribution facilities are much smaller and do not benefit from the economies of scale that transmission-level service provides. In proposing that BPA adjust the distribution cost component of the margin to take into account the similar purpose of utility/BPA delivery facilities, the DSIs are essentially proposing that similar functions be given similar costs for purposes of developing the typical margin. Such an adjustment could allow a margin determination which would be independent of the particular sample selected yet remain bound to the entire sample.

The joint data base was extracted primarily from utility cost of service studies, and therefore allows a detailed analysis of costs included in the distribution function category. This in turn allows a comparison of distribution costs incurred by retail industrial consumers with costs that would be incurred by the DSIs for receiving service from BPA. By comparing utility industrial consumer distribution costs with DSI delivery facility costs, BPA could identify the relationship between size of load and distribution cost. Reply Brief, DSI, R-DS-01, 25. It is noteworthy that BPA's DSI delivery costs (0.52 mills/kwh) are very close to the unit cost in the original DSI sample of 26 industrial consumers (0.55 mills/kwh) even though the average size of DSIs (170 average megawatts) is over five times greater. On the surface it would appear that about one half mill/kilowatthour is the limit to delivery facility costs for very large loads. Selection of either 0.53 or 0.55 mills/kwh would be reasonable in this instance and would implicitly recognize the significant size differentials of the DSIs and retail industrial consumers.

Comparing the approximate 0.53 mills/kwh cost of DSI delivery facilities to the weighted distribution cost of the retail industries included in the joint data base (approximately 0.87 mills/kwh) would result in an adjustment to the margin that would simultaneously recognize the purpose and the relative costs (and hence, size) of the facilities. This would achieve two desirable results. First, a measure of rate predictability would be added to future [page 148] rate adjustment proceedings. Second, in the event that the data base for implementing section 7(c)(2) were to be readdressed in the future, the criteria could be expanded with less concern about arbitrary limits to the size of load that would be eligible for inclusion.

**Decision**

*BPA adjusts the margin for size characteristics by substituting BPA's DSI delivery facility costs for the weighted distribution costs to industries in the joint data base. Although the record does not establish a clear relationship between size of load and margin based on documented utility intent, making such a substitution provides a reasonable method for taking size differences into account in developing the margin. To ignore the relationship between size of load and costs of delivery facilities would give undue weight to the smaller retail industrial consumers served over distribution facilities, thereby overstating the distribution cost component of the margin.*

**Issue #3**

*Should the 7(c)(2) analysis recognize any differences in seasonality of load between the DSIs and retail industrial consumers?*

**Summary of Positions**

BPA contends that retail industrial process loads tend not to vary across seasons, but instead remain fairly stable, similar to DSI loads. Carr and Taves, BPA, E-BPA-47, 16. NWU for the most part supports BPA’s position. Lessner, et al., NWU, E-NU-11SR, 10. The DSIs assert that there is no evidence that retail industrial margins are seasonally differentiated. Schoenbeck, DSI, E-DS-10R, 5-6. The PF-85 rate itself, according to the DSIs, adjusts for seasonality in the power cost component of the IP rate. Schoenbeck, DSI, E-DS-02, 6.

WUTC proposes applying a uniform demand charge, weighted to reflect the 27-month rate period. Appropriate uniform demand charges should recognize that the rate period is composed of 10 winter demand months and 17 summer demand months. Rolseth and Folsom, WUTC, E-NU-01SR, 3-5.

**Evaluation of Positions and Decision**

There appears to be general agreement among the litigants that seasonal loads are not a factor in developing the margin. No evidence has been submitted indicating that margins or margin components vary seasonally.

WUTC proposes to normalize demand charges over the 27-month rate period. However, BPA's test period is FY 1987, a 12 month period. WUTC has not provided a persuasive argument for weighting demand charges over the 27-month period the rates will be in effect, nor has it demonstrated how such an
[page 149] approach would address concerns regarding seasonality of the margin. BPA agrees with the DSIs that applying PF-85 rate charges properly adjusts for seasonality in the power cost component of the 7(c)(2) rate. Given that BPA's rate case is based on a 12-month test period, it would be inconsistent to use a 27-month period to reflect seasonality in the applicable wholesale rate. Furthermore, there is no evidence that margin costs are seasonally differentiated. Additional adjustments to the margin component or the power cost component of the IP rate are not appropriate.

**Issue #4**

*Should a premium be included in the margin to reflect the risk of revenue uncertainty to BPA in serving DSI loads?*

**Summary of Positions**

BPA did not explicitly address the possible risk of serving large loads in calculating the margin.

NWU argues that a risk premium should be included to account for the swing nature, and associated risks, of serving DSI loads. NWU recommends a risk premium based upon BPA's Revenue Uncertainty Analysis. Lessner, et al., NWU, E-NU-08, 15-18; Lessner, et al., NWU, E-NU-9R, 20-22; Lessner, et al., NWU, E-NU-11SR, 10-11.

ICP cites the DSIs' own statements that a number of DSI plants are now swing plants. DSI loads vary with business cycles; the character of DSI loads is quite poor and therefore should be charged higher margins. McCullough, ICP, E-IC-10, 3-6.

The DSIs oppose a risk premium on the grounds that risk is already reflected in the applicable wholesale rate via the Revenue Uncertainty Analysis. Also, the DSIs contend that there is no evidence of a risk premium component in retail industrial rates. Schoenbeck, DSI, E-DS-]OR, 7-9.

**Evaluation of Positions**

The margin to be added to the applicable wholesale rate to determine the IP-85 rate is to be "typical" of industrial rates of public agency customers. BPA recognizes that large changes in DSI loads will cause commensurate short term changes in revenues. ICP and NWU point out that the DSIs are now characterized as swing plants within the aluminum industry and that they thus pose a risk to BPA revenue recovery. The argument can be made that risks to metered requirements customers are lower because they have no investment in generating plant, therefore their power costs are variable costs, in contrast, power production costs are fixed costs to BPA. Therefore, BPA faces greater levels of risk of not covering costs in the event of major load curtailments by customers. However, no evidence was submitted demonstrating that retail industrial customers are subject to a risk component in the margins paid to retail utilities. Schoenbeck, DSI, E-DS-10R, 8.

[page 150]

In determining a "typical" margin, the Administrator should attempt to mirror utility practices of including costs in the margin. BPA recognizes that many retail utilities have minimum bill provisions established in their industrial rates in order to provide short-term protection against revenue declines due to load curtailment. In a sense, these could be considered the utilities' approach to dealing with risk. Such considerations are, however, more appropriately a rate design issue rather than a margin calculation consideration.

**Decision**

*A risk premium adjustment to the margin is not supported by the record. Parties proposing a risk premium to reflect DSI revenue uncertainty in the margin fail to demonstrate that utilities typically include a risk factor in their retail rates.*

### 3. Character of Service Adjustment

**Issue #1**

*Does the quality of service to the first quartile warrant an adjustment to the 7(c)(2) margin?*

**Summary of Positions**

BPA is not obligated to plan for or acquire resources for the purpose of serving the first quartile of the DSI load. As a result, first quartile service may be restricted if nonfirm energy is unavailable. The character of service adjustment accounts for BPA's right to restrict service to the first quartile. Carr and Taves, BPA, E-BPA-47, 19-20.

NWU contends that no character of service adjustment should be made to the margin. NWU asserts that full service to the first quartile is assured during the rate period. Lessner, et al, NWU, E-NU-11SR, 13.

APAC asserts that if BPA's historical margin calculation included some nonfirm energy sales to retail industrial consumers, any character of service adjustment must take the nonfirm nature of those sales into account. Cook and Shanker, APAC, E-PA-02, 22-23.

The DSIs believe that the character of service adjustment should take into account several factors. BPA can restrict first quartile service "at any time and for any reason" to assure BPA's ability to meet its other firm obligations. The existence of adverse water conditions is not required for interruption of the first quartile. BPA does not incur costs of planning and acquiring resources to serve the first quartile. Mizer, DSI, E-DS-11R, 3-4.
[page 151]

**Evaluation of Positions**

BPA acknowledges that the DSI first quartile, under rate case assumptions, would be the first market served with nonfirm energy. Carr, BPA, TR 2686. BPA states also that the first quartile could be served with provisional drafts, while nonfirm energy sales made under the NF rate are not made using provisional drafts. Carr, BPA, TR 2690-2691.

Although BPA operates its resources to serve the first quartile on a firm basis, it does not plan to acquire resources sufficient to serve the first quartile on a firm basis. Restrictions to the first quartile could occur if either adverse water conditions arose or if BPA were able to make more sales of surplus firm energy at the SP rate than it currently expects. Carr, BPA, TR 2689. Furthermore, in evaluating the "firmness" of service to the first quartile, BPA analyzes expected service under 40 different water conditions. Carr, BPA, TR 2700. The results of this analysis indicate that a portion of the first quartile will not need to be restricted in FY 1987, given current expectations of the load/resource situation. Past DSI operating levels are not pertinent to this aspect of the analysis.

NWU argues that sufficient nonfirm energy is forecasted to be available in all but the lowest water years to meet first quartile requirements. NWU also cites the DSIs' priority of claim to any available nonfirm energy. Furthermore, NWU cites the practice in which BPA operates its existing resources as if the DSI first quartile were a load that BPA must serve on a firm basis. NWU asserts that service to the DSI first quartile has historically been quite reliable relative to service to retail industrial consumers, and therefore if any downward adjustment for character of service is made, it should be based upon cost differences between providing firm service to the DSI first quartile with respect to providing firm service to retail industrial loads. Lessner, et. al, NWU, E-NU-11SR, 13-16.

NWU's contention that retail industrial consumers are served under contractual or other arrangements that provide for interruptions in service, thereby eliminating any need for a character of service adjustment to the margin, is not persuasive. Interruptibility provisions to loads that are considered firm are common in industrial contracts. Lessner, et al., NWU, E-NU-11SR, 14-15. BPA also has the ability to interrupt the second and third quartiles of the DSI load in certain situations, and these are loads that are considered firm for planning purposes. Carr, BPA, TR 2529.

APAC's position regarding appropriate treatment of nonfirm energy sales to retail industrial consumers in determining the character of service adjustment is well taken. However, it has not been shown that any retail industrial sales included in the joint data base were associated with nonfirm energy.

**Decision**

*A downward adjustment to reflect a lower quality of service to the first quartile is appropriate. Although many retail industrial consumers are served*
[page 152] *under contracts or other arrangements that provide for interruptions in service, it has not been shown that the contracts or the retail rates include elements related to nonfirm service to retail industrial consumers. Nor is there evidence on the record that the interruptibility of service to retail industrial consumers is significantly different from DSI second and third quartile interruptibility provisions. In contrast, service to the DSI first quartile is dependent on the availability of nonfirm energy. Under adverse water conditions BPA would not have sufficient resources to serve the entire first quartile in the test year given its projected loads and resources.*

**Issue #2**

*What rate should BPA use to reflect the cost of providing firm service to all four quartiles of the DSI load in determining the character of service adjustment?*

**Summary of Positions**

In order to account for the quality difference between Premium (100 percent firm) and Standard service to the DSIs, BPA uses the IP-85 Premium rate as the cost of providing firm service to the first quartile when calculating the character of service adjustment. Carr and Taves, BPA, E-BPA-47, 19-23.

APAC recommends that the Nonfirm Energy rate be subtracted from the PF-85 rate, rather than from the IP Premium rate, to quantify the premium that a typical industry would pay for firm service. According to APAC, the PF-85 rate is appropriate since its use would recognize the cost differences faced by preference utilities in serving industrial consumers with firm power as opposed to nonfirm energy. Cook and Shanker, APAC, E-PA-02, 23-24.

The DSIs contend that the character of service adjustment should recognize the difference between BPA's costs of serving other loads on a firm basis as opposed to those costs incurred in providing service to the first quartile. Mizer, DSI, E-DS-11R, 3.

**Evaluation of Positions and Decision**

BPA's intent in developing the character of service adjustment was to quantify the appropriate differential for providing nonfirm service to the first quartile based upon, in part, BPA's own cost incurrence. Carr, BPA, TR 2595. The relevant costs in this instance are the opportunity costs to BPA, not to public agencies. Carr, BPA, TR 2624. The primary difference between the IP Premium rate and the IP Standard rate relates to the distinction between serving the first quartile with firm power as opposed to nonfirm energy. Carr, BPA, TR 2624.

APAC does not support its assertion that the PF-85 rate is pertinent to BPA's cost of providing firm service to the DSI first quartile. The PF-85 [page 153] rate level is not indicative of either BPA's cost of serving the first quartile on a firm basis or of the revenues BPA would collect under the IP-85 Premium rate.

BPA uses the IP-85 Premium rate to determine the character of service adjustment as the proper measure of the cost of firm service to the entire DSI load.

**Issue #3**

*In determining the margin, how should BPA treat the portion of service to the DSI first quartile that is dependent on the availability of nonfirm energy?*

**Summary of Positions**

It is anticipated that the DSI first quartile will be partially served using surplus firm power unsold at the SP rate and surplus firm power made available during the fish migration assistance period and the precritical period. Carr and Taves, BPA, E-BPA-47, 20-21. Therefore, the character of service adjustment is calculated to reflect only the portion of first quartile load that is dependent on nonfirm energy availablility [sic].

APAC asserts that BPA understates the portion of service dependent on the availability of nonfirm energy. According to APAC, the whole purpose of the adjustment is to account for the fact that service is interruptible, so BPA should assume a factor of 100 percent. Cook and Shanker, APAC, E-PA-02, 24. The DSIs agree with APAC that BPA should recognize that 100 percent of the first quartile is subject to interruption at any time. Carter, DSI, E-DS-03, 14; Mizer, DSI, E-DS-11R, 3.

**Evaluation of Positions and Decision**

Any character of service adjustment should recognize that the current resource surplus provides a degree of certainty of service to the first quartile. Carr and Taves, BPA, E-BPA-46, 13-14. If BPA did not expect to have firm surplus energy available during the test period, then the DSIs' and APAC's argument that the character of service adjustment should take into account 100 percent nonfirm service would be persuasive. Current estimates indicate, however, that surplus firm energy will be available during the rate period.

From a contractual perspective, first quartile service is 100 percent interruptible. However, the probability is that, even under critical water planning, BPA would have to restrict service to only that portion of the first quartile not served with unsold surplus firm power; that is, power made available during the fish-migration assistance period and the precritical period and unsold surplus during the other 9 1/2 months. BPA, E-BPA-46, Table 4, Table A-4. Therefore, the character of service adjustment is calculated by taking into account the probability that first quartile service
[page 154] will not be entirely subject to restriction during the test period. The final proposal assumes 100 percent firm service during the fish migration and precritical period, and partial firm service during the remaining 9 1/2 months based on revised estimates of available (unsold) surplus firm energy.

**Issue #4**

*What is BPA's opportunity cost of providing first quartile service nonfirm energy?*

**Summary of Positions**

BPA measured the opportunity cost of providing service to the first quartile as the average nonfirm target revenue, exclusive of low cost displacement sales. Carr and Taves, BPA, E-BPA-100, Table 4.

APAC uses the NF Standard rate to quantify the difference between firm service and nonfirm service to the first quartile. Cook and Shanker, APAC, E-PA-02, 2 3-24.

The DSIs assert that BPA's true opportunity cost can be no higher than the average revenue for all nonfirm energy as estimated by BPA's nonfirm revenue analysis. The DSIs also suggest that the opportunity cost could actually be lower. If the nonfirm energy being used to serve the DSI first quartile were to become available to other nonfirm markets, the average nonfirm revenue would be further depressed. Carter, DSI, E-DS-03, 15-16.

**Evaluation of Positions**

BPA recognizes that an evaluation of the opportunity cost to serve the DSI first quartile should consider expected nonfirm market conditions during the rate period. The DSIs claim that BPA may not be able to sell all nonfirm energy now serving the DSI first quartile in alternative markets at the NF Standard rate. Carter, DSI, DS-03, 15-16. The DSIs' assert that the opportunity cost should be valued at a level lower than the projected average nonfirm energy revenue. Carter, DSI, E-DS-03, 15-16. However, the first quartile receives a higher level of service than other nonfirm markets. BPA operates its resources, within each operating year, to provide service to the first quartile as if it were a firm load. Carr, BPA, TR 2686. For this rate filing, BPA assumes that the DSI first quartile is served first with available nonfirm energy before competing markets are served. Carr, BPA, TR 2686-2687. There is a high likelihood that, particularly during certain portions of the year, BPA could be serving the first quartile with nonfirm energy during periods when it could be serving other markets at the NF Standard rate or possibly the NF Standard rate with guaranteed service. However, BPA acknowledges that the opportunity cost of serving the first quartile is lower during certain periods of the year when the supply of nonfirm energy is typically greater relative to demand. Therefore, sales under the NF Low Cost Displacement rate should be recognized in the derivation of the opportunity cost to serve the first quartile.

[page 155]

BPA also recognizes that available surplus firm power sold as nonfirm energy accounts for a portion of nonfirm revenues. This portion of BPA's nonfirm revenues is actually from sales of firm power that BPA cannot market under the Surplus Firm Power rate, so it is available for sales under the NF rate schedule or for first quartile service. BPA recognizes the amount of surplus firm power available for service to the first quartile by reducing the amount of service which is dependent upon the availability of nonfirm energy. The derivation of opportunity costs should consider only those sales that have not been accounted for elsewhere. Therefore, the calculation of BPA's opportunity cost of providing service to that portion of the first quartile which is dependent on availability of nonfirm energy should be based on nonfirm energy sales from nonfirm resources, and should not include sales of surplus firm power which may be sold under the NF-85 rate schedule.

**Decision**

*The evidence on the record indicates that the opportunity cost to serve the first quartile varies depending on season, annual rainfall, and other factors. The average energy revenue derived from sales of available nonfirm energy, including both NF High Cost and Low Cost Displacement rate sales, is an appropriate representation of BPA's opportunity cost of serving the DSI first quartile with nonfirm energy. Surplus firm power available for providing service to a portion of the first quartile is recognized elsewhere in the character of service adjustment. Therefore, sales of surplus firm power under the NF-85 rate schedule will not be included in the derivation of BPA's opportunity cost of serving the first quartile.*

**Issue #5**

*Is BPA's development of the character of service adjustment consistent with Exhibit U, as referenced in the power sales contracts?*

**Summary of Positions**

BPA did not explicitly address Exhibit U in the 7(c)(2) industrial margin study.

NWU believes that BPA's character of service adjustment is indirect conflict with provisions of Exhibit U. McCullough, NWU, E-NU-07. NWU also believes that Exhibit U mandates the methodology for determining the post-1985 DSI rate. Reply Brief, NWU, R-NU-01, 18.

**Evaluation of Positions**

NWU contends that line 1 of Exhibit U dictates that BPA charge firm rates to the DSIs for all four quartiles of DSI load. McCullough, NWU, E-NU-07, 1; Reply Brief, NWU, R-NU-01, 18. NWU also claims to demonstrate algebraically that BPA's character of service adjustment results in no margin being added to the nonfirm energy element of the adjustment, and that the first quartile of the DSI load is in fact being priced at the nonfirm energy rate, thereby violating the requirements of the exhibit. McCullough, NWU, E-NU-07, 3.
[page 156]
NWU incorrectly interprets Exhibit U insofar as determination of the DSI margin is concerned. Exhibit U was developed to demonstrate, in general terms, the sequencing of the post-1985 rate determination process BPA expected to follow. Certain details to the rate formulation process were included in the exhibit for clarification and discussion purposes only. Items such as percentage service to the DSI first quartile, the multiplier representing the DSI rate, including margin, and the wholesale rate deriviation [sic] were meant to provide understanding to all parties of BPA's intentions in developing the post-1985 rates.

The transcript from the 1981 rate adjustment proceedings where Exhibit U was introduced clearly demonstrates that sequencing and consistency between the sequencing steps were the main issues resulting in the development of the exhibit. (See 1981 Wholesale Power and Transmision [sic] Rate Adjustment Proceedings, TR 6116-6129, 6652-6654.) BPA stated during cross-examination that item one of Exhibit U was a formula for determining the amount of revenues that BPA would recover from sales to the DSIs consistent with item two of the exhibit, which develops the costs to serve the DSIs.

NWU, in contrast, asserts that Exhibit U is a formula for determining the DSI rate itself. NWU says that BPA's development of a character of service adjustment results in no markup to the nonfirm energy used to serve the first quartile (Reply Brief, NWU, R-NU-01, 18) and relies on an algebraic derivation of BPA's character of service adjustment to support this contention. McCullough, NWU, E-NU-07, Attachment 1. The conclusions drawn by NWU from the mathmatics [sic] of Attachment 1 are logically inconsistent. The in consistency stems from the algebraic derivation of the margin-based rate. It is true that the NF-85 rate (average revenue) is used in the development of the character of service adjustment, and hence impacts the IP Standard rate. However, derivation of the margin is not relevant to the application of the rate in this case. The two processes are not intertwined. BPA serves all levels of DSI operation under a single rate (IP Standard or IP Premium), rather than having discrete rates to each quartile. The NF rate is simply used to modify the IP Premium rate margin (applied to all four quartiles of service) to account for the lower quality of service under the IP Standard rate margin (also applied to all four quartiles of service). Since the components of the margin are added prior to adding the applicable wholesale rate and then multiplying by the DSI loads pursuant to Exhibit U, it cannot be asserted that BPA is charging a discrete rate for service to the first quartile.

Item 1 of Exhibit U must be interpreted in a manner that is consistent with the language in section 7(c)(2)(B), which provides that the Administrator take into account "other service provisions" when developing the DSI margin-based rate. The lower quality of service to the first quartile of the DSI load must be recognized in the development of the post-1985 DSI rate. In order to be consistent with section 7(c)(2), the margin that is combined with the applicable wholesale rate to public agencies and cooperative customers in Item 1 of Exhibit U can only be a margin which recognizes the lower quality of service to the DSI first quartile. Indeed, Item 2 of Exhibit U, which illustrates the derivation of costs to serve the DSIs for the purpose of the [page 157] DSI delta determination, recognizes the costs of serving a portion of the DSI load with nonfirm energy. Therefore, it is appropriate to recognize the nonfirm nature of service to a portion of the DSI first quartile in the margin in order to provide for consistency in deriving revenues and costs in the DSI delta determination.

**Decision**

*BPA's treatment of the first quartile in its character of service adjustment is consistent with Exhibit U, as well as consistent with section 7(c)(2).*

[page 159]

## VII. SECTION 7(b)(2) RATE TEST STUDY

### A. Introduction

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct a rate test in order to protect BPA's preference and Federal agency customers' (7(b)(2) customers') wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test could result in a reallocation of casts from the 7(b)(2) customers to BPA's other rate classes.

The methodology to implement section 7(b)(2) was developed in a 7(i) process that preceded the 1985 wholesale power and transmission rate filing. That 7(i) process culminated in the Administrator's Record of Decision for Section 7(b)(2) (7(b)(2) ROD). The 7(i) process conducted to develop the implementation methodology for section 7(b)(2) was designated as the first phase of the 1985 rate filing; the 7(b)(2) ROD and the record on which it is based are a part of the record of this proceeding. However, the issues resolved in the 7(b)(2) ROD are the law of the case (Judge Wenner, TR 4; *see also* O-17, O-19, O-21, and O-28) and are therefore not matters to be reconsidered for this Record of Decision. Certain issues requiring interpretation of the statute were resolved in the Legal Interpretation for section 7(b)(2) (49 FR 23998 (1984)). The Legal Interpretation was developed in a public comment process that also is considered a part of the 1985 rate filing; the Legal Interpretation and the record underlying it are a part of this proceeding. The following sections discuss issues that were reserved for this proceeding.

The section 7(b)(2) rate test was performed for the first time in conjunction with the 1985 rate filing. The purpose of the Section 7(b)(2) Rate Test Study is to describe the application and results of the section 7(b)(2) rate test methodology. The study describes the development of the implementation methodology, including the Legal Interpretation and the 7(i) process. It also describes the sequence of steps used by the Supply Pricing Model (SPM) to calculate the two sets of rates that are compared in the rate test. The study then discounts and compares the two sets of rates and calculates the difference. If a positive difference between the rates in the program case and the rates in the 7(b)(2) case had existed, an amount of costs to be reallocated in the rate case test year (FY 1987) would have been calculated.

**B. Financing Benefits**

Section 7(b)(2) directs BPA to quantify the additional resource costs that would be faced by the 7(b)(2) customers if the Northwest Power Act's provision [page 160] for BPA acquisition of resources were not in effect. The financing benefits analysis was performed by BPA witness Paul M. Heid of Wertheim & Co., BPA's financial adviser. 7(b)(2) ROD at 15. The analysis appears as an Appendix to the Section 7(b)(2) Rate Test Study, E-BPA-03.

**<u>Issue #1</u>**

*What time period should be considered when determining the interest rate for the combustion turbines assumed to provide system reserves to the 7(b)(2) case?*

**<u>Summary of Positions</u>**

The combustion turbines used to value forced outage reserves in the value of reserves analysis were assumed to be available to provide reserves in 1983. Armstrong, BPA: E-BPA-54R, 2; STR 764. BPA's financing benefits analysis for the initial proposal therefore assumed that the combustion turbines would be built and financed during calendar year 1982. BPA, E-BPA-03, A-7. The interest rate calculated for the analysis was computed based on the Bond Buyer 30-Year Revenue Bond Index for calendar year 1982. BPA, E-BPA-03, A-10.

PPC supports BPA's time period for calculating the interest rate. Wolverton and O'Meara. PPC, E-PP-04R, 15-16.

The DSIs claim that the time periods over which the interest rates in the program case and the 7(b)(2) case were calculated are not comparable. Initial Brief, DSI, B-DS-07, 119-120. They propose that the Bond Buyer Index average, on which the interest rate is based, be calculated for January through July 1982. Peseau, DSI, E-DS-06, 14; Pre-Hearing Brief, DSI, P-DS-01, 49.

**Evaluation of Positions**

The DSIs' criticism of BPA's method of calculating the interest rate for reserves in the 7(b)(2) case is based on the claim that the two (program case and 7(b)(2) case) interest rates to BPA's initial proposal were not comparable. The DSIs support their method of a using a 7-month average of the Bond Buyer Index as a benchmark for calculating the 7(b)(2) case interest rate by concluding that "the same time period" would then be used in the 7(b)(2) case as in the program case. Peseau, DSI, E-DS-06, 14. This is incorrect. The program case interest rate is estimated using a full year's data, Armstrong, BPA, E-BPA-54R, 2; STR 765; the DSIs do not provide evidence for their claim that 7 months' data were used. The DSI "check on the reasonableness" of using the 7-month average of the Bond Buyer Index as the benchmark 7(b)(2) case, Peseau, DSI, E-DS-06, 15, is also in error. The projected BPA borrowing rate is based not on the rate for Treasury bonds, as the DSIs imply, but on the rate for 20-year U.S. Government Bonds. BPA, E-BPA-07A, Chapter 14, A-3 and A-4. The DSI comparison of the Bond Buyer Index and the Treasury Bond averages is therefore not appropriate.
[page 161]
PPC supports BPA's use of a full year's data by pointing out that to assume all financing would occur for the construction of the combustion turbines in a 7-month period, as the DSIs suggest, is unrealistic. Wolverton and O'Meara, PPC, E-PP-04R, 15.

The DSIs' Initial Grief continues to assert that the interest rate for construction of the combustion turbines in 1982 should be higher than in BPA's initial analysis. It states that "interest rates in *the year* prior to October 1, 1982, were significantly higher" (emphasis added). Initial Brief, DSI, B-DS-01, 121-122. This statement appears to support BPA's use of a 1-year average of the Bond Buyer Index.

BPA acknowledges that basing the interest rate on the average of the Bond Buyer Index for FY 1982 is more reasonable than basing it on calendar year 1982 as was done for the initial proposal in order to be consistent with the interest rate in the program case. Armstrong, BPA, STR 766-767.

**Decision**

*The DSI proposal to base the financing cost for the 7(b)(2) case on the first 7 months of 1982 is neither reasonable nor supported by the evidence. The financing cost for reserve resources in the 7(b)(2) case is based on the Bond Buyer Index average for FY 1982. This provides consistency of bases for the program case and 7(b)(2) case analyses.*

**Issue #2**

*What basis should be used to estimate the interest rates for the financing benefits analysis?*

**Summary of Positions**

BPA's analysis of financing benefits uses the Bond Buyer 30-Year Revenue Bond Index as a benchmark for estimating the interest rate for reserve resources in the 7(b)(2) case and for additional resources. The financing rate for the reserve resources is calculated by adding 50-75 basis points to the average 1982 Bond Buyer Index. The financing rate for the additional resources is estimated by adding 75-100 basis points to the Bond Buyer Index of May and June 1984. BPA, E-BPA-03, A-9 and A-10; Heid, BPA, E-BPA-30, 6-7.

The DSIs support BPA's use of the Bond Buyer Index as a benchmark, Peseau, DSI, E-DS-06, 12-13, but they propose that 125 basis points be added to the Bond Buyer Index for 1982. Peseau, DSI, E-DS-06, 13-14 and 15-19; Pre-Hearing Brief, DSI, P-DS-01, 49.

OPUC suggests that BPA "should reconsider its use of the yields on the Bond Buyer Index as a proxy for the yields on the bonds" of the financing entity. Nyegaard, OPUC, E-OP-02, 4. OPUC proposes a interest rate for the reserve resources 100 basis points higher than that used by BPA. Nyegaard, OPUC, E-OP-02, 7; Pre-Hearing Brief, OPUC, P-OP-01, 4. For the additional [page 162] resources, OPUC claims only that the 75-100 basis points BPA added to the Bond Buyer Index was not enough. Nyegaard, OPUC, E-OP-02, 7-8; Pre-Hearing Brief, OPUC, P-OP-01, 4.

PPC argues that BPA overstates the costs of both the combustion turbines and future additional resources by not recognizing the relatively low risk of constructing nonnuclear resources. Initial Brief, PPC, B-PP-01, 19-20; Reply Brief, PPC, R-PP-01, 4, 7. PPC adds that the interest rate for additional resources is too high because it is based on the Bond Buyer Index average for May and June 1984. Reply Brief, PPC, R-PP-01, 6-7.

**Evaluation of Positions**

Both the DSIs and OPUC base much of their arguments for higher financing costs on their claim that the bond market would perceive the Washington Public Power Supply System (Supply System) and the financing entity as similar credit risks. Peseau, DSI, E-DSI-06, 16; Nyegaard, OPUC, E-OP3; Initial Brief, OPUC, B-OP-01, 25. BPA agrees that the membership of the financing entity assumed for section 7(b)(2) would be substantially the same as that of the Supply System. However, significant differences exist. The resources that the section 7(b)(2) financing entity is assumed to construct are nonnuclear, while the Supply System's construction program is nuclear. Inherent therein are differences in resource technology reliability, construction cost, and length of construction period. Those differences would all serve to cause the bond market's perception of risk for the construction projects of the section 7(b)(2) financing entity to be less than the perceived risk of the Supply System. Heid, BPA, E-BPA-53R, 2-3. PPC points out the higher risks in a nuclear construction program relative to a nonnuclear program: the longer necessary lead time, including financial commitment; the high capital cost; and technical difficulties that can lead to cost overruns and even plant terminations. Wolverton and O'Meara, PPC, E-PP-04R, 18-20.

OPUC asserts that the resource-related differences between the financing entity and the Supply System are irrelevant because the Supply System's bonds are backed by BPA net billing. Initial Brief, OPUC, B-OP-01, 24; Reply Brief, WUTC/OPUC, R-OP/WU-01, 15. This argument only enforces BPA's position that the 7(b)(2) financing entity and the Supply System are not similar investment risks, since the bonds of the financing entity would not be backed by net billing arrangements. WUTC/OPUC claims that BPA's acquisition of resources in the program case (the source of financing benefits) "is the closest thing to a net billing arrangement and would have a similar effect on financing cost rates." Reply Brief, WUTC/OPUC, R-OP/WU-01, 15. The WUTC/OPUC claim is not only unsubstantiated, it is untrue. Net billing is a unique solution to the recurring situations arising from the region's Hydro-Thermal Power Program. Net billing is distinct from BPA's resource acquisition authority in two respects. First, net billing requires the provision of Federal power to the participants in the resource construction, whether or not the resources ever generate power; acquisition does not. Second, net billing provides for direct Federal backing for resource construction financing; acquisition does not. The two arrangements thus cannot be argued to "have a similar effect" on [page 163] the bond market's perception of the financing entity and its bonds' financial strength.

OPUC suggests that the 7(b)(2) financing entity would face interest rates for additional resources comparable to the actual yield on the bonds issued by Snohomish County Public Utility District No. 1 (Snohomish PUD) in November 1983. This alleged comparability is used to support OPUC's argument that the financing cost for additional resources should be higher than was estimated by BPA. OPUC cites the market's perception of similarities of the financing entity and the Supply System, and the default on Supply System bonds, as support for the higher interest rates that would result from using the rates for Snohomish PUD as a benchmark. Nyegaard, OPUC, E-OP-02, 7-8; Initial Brief, OPUC, B-OP-01, 27. OPUC's claim for similar credit risks of the 7(b)(2) financing entity and Snohomish PUD is unsubstantiated. Instead, the bond market would view the 7(b)(2) entity's financing risk as less than that of Snohomish PUD because of the sharing of risks among all the members of the joint operating agency. Heid, BPA, E-BPA-53R, 4. WUTC/OPUC supports its claim of the similarity of Snohomish PUD and the financing entity by stating, "[i]f (OPUC) is correct about what would have happened in 1982, (OPUC) is clearly correct about what happened in 1984." Reply Brief, WUTC/OPUC, R-OP/WU-01, 17. Not only is the WUTC/OPUC statement clearly an unsubstantiated leap of faith, but the conditional on which the sentence is based is shown *infra* to be untrue.

Both the DSIs and OPUC argue that BPA has developed too low an estimate for the interest rates at which the 7(b)(2) financing entity could sell its construction bonds. The DSIs would add 125 basis points to the Bond Buyer Index in 1982 to reflect the similarity of the 7(b)(2) entity membership to that of the Supply System, discussed above, and the construction-related and dry-hole risks. The DSIs claim that the BPA analysis "assumed away" the construction risk and dry-hole risk of the combustion turbines in the value of reserves analysis, and that an additional 50-75 basis points should be added to the Bond Buyer Index to account for those risks. Peseau, DSI, E-DS-06, 17-19. The DSI witness admitted during cross-examination that his evaluation of the construction and dry-hole risks of the value of reserves combustion turbine (the Beaver plant) was based on his experience while employed at OPUC (Peseau, DSI, STR 774-775), but that he had performed no specific analysis of those risks for that plant. Peseau, DSI, STR 779. Consequently, the proposed 50-75 basis points adjustment is unsupported. The BPA analysis did not "assume away" the construction-related and dry-hole risks, but assumed that those risks would be borne by the suppliers of the components of the combustion turbines, and by the participants of the 7(b)(2) entity in the case of the additional resources. BPA, E-BPA-03, A-6. These are common arrangements in utility construction financings, especially for construction of established-technology generation plants by joint operating agencies. Heid, BPA, E-BPA-30, 3-4; E-BPA-53R, 4-6; STR 715; STR 717.

OPUC, although proposing that the section 7(b)(2) financing benefits analysis should use a benchmark different from the Bond Buyer Index, yet recommends a financing cost for the combustion turbines of 100 basis points
[page 164] than the BPA estimate (which is based on the Bond Buyer Index). The 100 basis points represents the average difference between the Bond Buyer Index and the actual "net interest cost rate" of Supply System bond issues in February and May 1982. Nyegaard, OPUC, E-OP-02, 4. OPUC's proposed financing rate thus incorporates the 50-75 basis point adder the BPA analysis uses to reflect the effect of the Supply System bonds issued in 1982. Plus 100 basis points to account for "the perceived problems of the Supply System." Nyegaard, OPUC, E-OP-02, 6-7; STR 756. The Supply System effect is doublecounted by OPUC. The WUTC/OPUC claim that BPA's testimony is remiss in not explaining the reason for the 100 basis points difference between the Bond Buyer Index yields in 1982 and the Supply System bond yields, Reply Brief, WUTC/OPUC, R-OP/WU-01, 16, is not pertinent. The interest cost of the Supply System bonds, and the difference between that cost and the Bond Buyer Index, is irrelevant in that BPA does not recognize any similarity between the Supply System and the 7(b)(2) financing entity for purposes of the financing benefits analysis, as discussed *supra*. Similarly, for the additional resources, OPUC argues that the BPA analysis "fails to take into account the interest rate premium that investors would have demanded before loaning money to the public bodies that are also Supply System participants." Nyegaard, OPUC, E-OP-02, 7. OPUC's claim is not true. BPA's analysis added 75-100 basis points to the Bond Buyer Index expressly to incorporate the impact of the Supply System default on the market's perception of risk inherent in the hypothetical financing of the 7(b)(2) entity. BPA, E-BPA-03, A-9 and A-10; Heid, BPA, E-BPA-30, 6-7. The distinction that WUTC/OPUC attempts to make between the two parts of the WUTC/OPUC adder to the Bond Buyer Index is unclear. The 100 basis points above and beyond BPA's 50-75 basis points adder seems to be not a direct result of the participation of most of the 7(b)(2) customers in the Supply System. Instead, the 100 basis points is an estimate of the lack of "willingness or ability of the participants to raise electric rates" to pay their debt service obligations. Reply Brief, WUTC/OPUC, R-OP/WU-01, 16. The 100 basis points amount is unsubstantiated. In any case, whether or not the Supply System existed concurrently with the financing entity, presumably the bond market would evaluate this particular risk when pricing the financing entity's bonds.

As discussed *supra*, PPC correctly points out the higher interest costs that would likely be faced by an entity constructing nuclear resources, rather than nonnuclear resources. The 20-25 basis point differential suggested by BPA, Heid, BPA, STR 704-705, would not, however, logically be *subtracted*, as PPC suggests, from the interest rate determined by BPA's analysis. The Bond Buyer Index cannot be assumed to be based upon only public utilities constructing nuclear power plants, and BPA's adder for additional risk is not based upon nuclear resource construction. It would thus be reasonable only to *add* the 20-25 basis points if the financing entity were constructing nuclear resources. PPC provides two additional reasons for its claim that the financing rate for additional resources should be lower than in BPA's analysis. First, PPC claims that BPA "ignores the lessening negative affect (sic) over time of the Supply System default." PPC does not quantify the amount which the Supply System effect would be reduced over the 5-year test period. PPC asserts that BPA admitted in cross-examination its "oversight" in
[page 165] not considering this "lessening" effect. Reply Brief, PPC, R-PP-01, 6. a careful reading of the transcript, however, shows that the BPA analysis did not quantify the reduction in the effect of the Supply System default because it would have been speculative to do so. Heid, BPA, STR 693. The effect of the Supply System default itself is impossible to quantify. Heid, BPA, E-BPA-30, 7. PPC provides no quantification of the impact consideration of the "lessening" effect of the Supply System default would have on the 7(b)(2) rate test. Second, PPC seems to suggest that use of the Bond Buyer Index for May and June 1984 as a basis is unreasonable because interest rates during that period were abnormally high. Reply Brief, PPC, R-PP-01, 6-7. Interest rates do fluctuate. BPA's analysis in Appendix a of E-BPA-03 does not purport to project interest rates for the entire 7(b)(2) rate test period. It simply provides a basis for that projection using data as recent as possible and using as little speculation as possible. Heid, BPA, STR 693. The fact that interest rates have declined since the analysis was performed, Reply Brief, PPC, R-PP-01, 6-7; Heid, BPA, STR 693-4, provides no justification for BPA picking and choosing the base period for its analysis.

**Decision**

*The basis for the BPA financing benefits analysis is sound. The Bond Buyer 30-Year Revenue Bond Index provides a useful benchmark for the interest costs of the 7(b)(2) financing entity. The margins by which BPA increased the Bond Buyer Index are reasonable approximations of the effect on the bond market of the Supply System 1982 bond issues and subsequent default.*

### C. Reserve Benefits

Section 7(b)(2) requires the quantification of the benefits to the 7(b)(2) customers arising from the system reserves provided by BPA 's restriction rights on the DSI loads. These benefits become a cost in the 7(b)(2) case, since the 7(b)(2) customers are required to provide their own system reserves.

**Issue #1**

*How should reserve benefits be quantified?*

**Summary of Positions**

BPA quantifies reserve benefits using the methodology used for the value of reserves analysis performed for the 1985 WPRDS. The analysis performed for the 7(b)(2) rate test required two changes to the WPRDS analysis. First, the financing benefits analysis performed for the reserve resources indicates that the 7(b)(2) customers could have financed the combustion turbines in 1982 at an interest rate lower than the BPA borrowing rate in the value of reserves analysis. This lower interest rate is used in the 7(b)(2) case, thereby [page 166] reducing the debt service and thus the value of reserves below that calculated in the 1985 WPRDS. Second, the value of reserves was reduced by the proportion of DSI loads that are not "within or adjacent" to 7(b)(2) customer service areas. This step reflects the assumption that a portion of the DSI load continues to be served by BPA, or is served by entities other than 7(b)(2) customers. BPA, E-BPA-03, 18-19; Armstrong, BPA, E-BPA-32, 12.

The DSIs assert that the reserve benefits provided by the DSI first quartile, represented by the character of service adjustment in the program should be shown as a cost in the 7(b)(2) case. Peseau, DSI, E-DS-06, 5; Pre-Hearing Brief, DSI, P-DS-01, 46-47; Initial Brief, DSI, B-DS-01, 115; Reply Brief, DSI, R-DS-01, 39. The DSIs also submit that the assumption of firm service to the DSI first quartile in the 7(b)(2) case requires an increased reserve requirement for that additional load. Initial Brief, DSI, B-DS-01, 118; Peseau, DSI, E-DS-06, 8. The DSIs argue that the cost of the combustion turbines used to value reserves should not be scaled down in the 7(b)(2) case as done in the program case to reflect the amount of the Federal reserve requirement. Peseau, DSI, E-DS-06, 6-7; Pre-Hearing Brief, DSI, P-DS-01, 47-48.

PPC believes that the proportion of DSI load that is not "within adjacent" should be calculated using four quartiles of DSI load rather than the three quartiles BPA uses. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 5; Pre-Hearing Brief, PPC, P-PP-01, 4; Initial Brief, PPC, B-PP-01, 10.

**Evaluation of Positions**

Reserve benefits, the absence of which increases the 7(b)(2) customers' cost of power in the 7(b)(2) case, are calculated using the same value of reserves analysis as is performed for each rate filing. BPA, E-BPA-03, 18. The decision to determine reserve benefits in this manner was made during the hearing that developed the implementation methodology for section 7(b)(2). 7(b)(2) ROD at 9. The 7(b)(2) ROD is the law of this case, Judge Wenner, TR 4; *see also* O-17, O-19, O-21, and O-28; the use of the value of reserves analysis to quantify reserve benefits is therefore not at issue in this proceeding.

The value of reserves analysis does not value BPA restriction rights on the first quartile of DSI load. The reason for this is that BPA does not plan or acquire resources to serve the first quartile, BPA, E-BPA-08, 335; Peters, BPA, E-BPA-57R, 10, as discussed more fully in Chapter VIII, Section H. The DSIs cite the character of service adjustment to the 7(c)(2) margin as support for the assertion that the reserves they believe are provided by the DSI first quartile should be valued in the 7(b)(2) case. Peseau, DSI, E-DS-06, 4. The character of service

adjustment recognizes the interruptible character of service to the first quartile, Carr and Taves, BPA, E-BPA-48SR, 5, but does not imply that the reserves provided by the first quartile require valuation in some other manner. BPA, E-BPA-08, 336. The DSI argument itself quotes the 7(b)(2) ROD: "A determination will be made in the relevant rate proceeding as to whether the restriction rights on the first quartile of DSI load *provide*
[page 167] *reserves*" (emphasis added). Peseau, DSI, E-DS-06, 3; 7(b)(2) ROD at 11. That the restriction rights on the first quartile "*have value*" (emphasis in original), Peseau, DSI, E-DS-06, 4-5, is not a sufficient reason for increasing the reserve costs of the 7(b)(2) customers in the 7(b)(2) case. The DSI contention that not including the first quartile in the value of reserves analysis "incorporates an inappropriate bias in the 7(b)(2) rate test analysis," Reply Brief, DSI, R-DS-01, 41, is not germane here. BPA uses the rate case value of reserves analysis to value reserve benefits (pursuant to the 7(b)(2) ROD); the rate case value of reserves analysis does not consider the first quartile. The 7(b)(2) rate test cannot be said to be biased inappropriately in that the correct method is used.

The DSI argument that the reserve requirement in the 7(b)(2) case should be increased to account for the increased firm load (the DSI first quartile) from the program case is based on an incorrect perception of the basis for the determination of the Federal reserve requirement. The DSIs support their position by citing BPA's method of calculating the federal reserve requirement in 1982 according to firm power loads. Peseau, DSI, E-DS-06, 8. That method is not germane here: the current methodology determines the federal reserve requirement according to "resources in operation during the test year." BPA, E-BPA-08, 337; Armstrong, BPA, E-BPA-54R, 5. a change in firm loads will not affect the reserve requirement. Armstrong, BPA, STR 745.

The third point made by the DSIs related to reserve benefits is that the full amount of reserve resources, not a scaled-down amount, would have been built by the 7(b)(2) customers in the 7(b)(2) case. The DSIs claim that the 7(b)(2) customers would thus face the entire cost of the combustion turbines, not the proportion of the reserve requirement divided by the plants' capability. Peseau, DSI, E-DS-06, 5-7. This issue is rendered moot by the decision in the 7(b)(2) ROD to quantify reserve benefits using the value of reserves analysis performed for each rate filing. Armstrong, BPA, E-BPA-54R, 6. The value of reserves analysis "scales down" the combustion turbine costs for the amount of reserves needed, BPA, E-BPA-08, 343; reserve benefits must be calculated in the same fashion. Armstrong, BPA, E-BPA-54R, 6.

PPC proposes that the proportion of "within or adjacent" DSI loads should be calculated based on four quartiles instead of three. No reason or support was advanced for this proposal. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 5. Using three quartiles of DSI load to calculate the proportion that is "within or adjacent" is reasonable in that the value of reserves analysis, which the "within or adjacent" proportion adjusts, is based on three quartiles. The analysis is thus internally consistent. Armstrong, BPA, E-BPA-54R, 4.

**Decision**

*BPA's method to calculate reserve benefits is proper. It uses the value of reserves analysis performed for the rate filing, adjusted only for financing benefits and the proportion of "within or adjacent" DSI loads. It thus comports with the 7(b)(2) ROD.*

[page 168]

**Issue #2**

*How should the costs of reserve resources be allocated in the 7(b)(2) case?*

**Summary of Positions**

BPA allocates the costs of reserve resources associated with the proportion of "within or adjacent" DSI loads to the 7(b)(2) customers. BPA, E-BPA-03, 19-20; Armstrong, BPA, E-BPA-32, 10; E-BPA-54R, 3.

The DSIs support BPA's method. Peseau, DSI, E-DS-16R, 1.

PPC argues that the cost of reserve resources in the 7(b)(2) case should be allocated to "contract and surplus power loads" as well as to the 7(b)(2) customers. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 3; Pre-Hearing Brief, PPC, P-PP-01, 3-4; Initial Brief, PPC, B-PP-01, 6-9. PPC claims that BPA's allocation is inequitable and biases the rate test toward triggering. Reply Brief, PPC, R-PP-01, 9-10.

**Evaluation of Positions and Decision**

PPC originally claimed that BPA's allocation of the cost of reserve resources in the 7(b)(2) case is a "problem," but did not provide any basis for the claim. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 3. PPC asserts that BPA's allocation is inequitable in that it provides for "different treatment between the two cases." Reply Brief, PPC, R-PP-01, 9-10. The 7(b)(2) implementation methodology, as summarized In Appendix C of the 7(b)(2) ROD, explains that "public utilities will incur a level of costs based on the value of the reserves provided by the DSI restriction rights as determined in BPA's rate proposal from those DSIs that are within or adjacent." 7(b)(2) ROD at 43. The purpose of the reserve benefits analysis is to determine the costs that would be borne by the 7(b)(2) customers in the 7(b)(2) case. Armstrong, BPA, STR 736. The value of reserves analysis quantifies those costs; the next step is clearly to allocate the costs to the 7(b)(2) customers. Armstrong, BPA, E-BPA-54R, 3.

BPA's allocation to the 7(b)(2) customers of the costs of the reserve resources in the 7(b)(2) case, adjusted for the proportion of "within or adjacent" DSI loads, is reasonable. The allocation of costs is consistent with the implementation methodology described in the 7(b)(2) ROD. The reserve benefits amount represents the costs that the 7(b)(2) customers would bear in the 7(b)(2) case to provide their own system reserves.

**D. Section 7(g) Costs**

Section 7(b)(2) refers specificially [sic] to certain costs whose treatment for ratemaking is specified in section 7(g): conservation, resource and conservation credits (billing credits), experimental resources, and uncontrollable [page 169] events.  In addition, section 7(b)(2) defines these applicable 7(g) costs as those that are "charged such customers" (the 7(b)(2) customers).  The Legal Interpretation for section 7(b)(2) (49 FR 23998, 24000 (1984)) prescribes that the applicable 7(g) costs will be excluded from the program case rates before they are compared with the 7(b)(2) case rates.  As further explained in the 7(b)(2) ROD, the 7(b)(2) case rates will include the applicable costs of experimental resources and uncontrollable events; and they will include the costs of billing credits and conservation to the extent that those resources are required to serve the 7(b)(2) customers' loads in the 7(b)(2) case.  7(b)(2) ROD at 4-5.

During this proceeding, APAC's testimony related to the treatment of 7(g) costs was stricken.  *See* O-28.  That testimony addressed issues of methodology that were decided in the section 7(b)(2) Legal Interpretation and the 7(b)(2) ROD.  PPC's testimony on the treatment of 7(g) costs, however, was not stricken insofar as it pertained to modeling of the rate test rather than to the 7(b)(2) implementation methodology.  *See* O-21.

**Issue #1**

*How should section 7(g) costs be treated?*

**Summary of Positions**

The Supply Pricing Model calculates the rates for the program case by simulating the calculations made for the rate filing as closely as possible.  BPA, E-BPA-03, 9; Armstrong, BPA, E-BPA-32, 9.  Consequently, savings from BPA conservation programs are netted out of the program case load forecast, and the costs of BPA conservation programs are allocated to rates.  Armstrong, BPA, STR 761.  For the 7(b)(2) case load forecast, the savings from BPA conservation programs are added back to the loads, Armstrong, BPA, E-BPA-54R, 6-7; E-BPA-03, 16; STR 761, and the costs of BPA conservation programs are excluded from the 7(b)(2) case rates.  BPA, E-BPA-03, 18; Armstrong, BPA, STR 761.  For the 1985 rate filing, conservation costs are the only applicable 7(g) costs.  Armstrong, BPA, E-BPA-32, 14-15; STR 729.

PPC proposes that the 7(b)(2) customers' load should be the same in the 7(b)(2) Case as in the program case.  That is, programmatic conservation savings should not be added back to the loads in the 7(b)(2) case.  Wolverton, Lucas, and Spettel, PPC, E-PP-01, 14; Pre-Hearing Brief, PPC, P-PP-01, 7-8; Initial Brief, PPC, B-PP-01, 15-18.  In addition, PPC appears to suggest that the array GENOTH more accurately represents 7(g) costs than does the array CONSRV.  Wolverton, Lucas, and Spettel, PPC, E-PP-01, 15; Pre-Hearing Brief, PPC, P-PP-01, 7.

APAC supports PPC's position that both cases should use the same load forecast.  Initial Brief, APAC, B-PA-01, 48-50.
[page 170]
The DSIs disagree with the PPC position on the issue of 7(g) costs.  Peseau, DSI, E-DS-16R, 2.

The ICP agrees with BPA's use of the CONSRV array rather than GENOTH.  McCullough, ICP, E-IC-16R, 3.

**Evaluation of Positions**

PPC algebraically equates (a) the subtraction of 7(g) costs from the program case rates before the rate test is performed with (b) adding those costs to the 7(b)(2) case rates. PPC is concerned that the 7(b)(2) customers receive "no power for the resources paid for through that adjustment." PPC would omit the adjustment of loads in the 7(b)(2) case to rectify the situation. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 14. APAC adds that increasing the 7(b)(2) case loads by the conservation savings in the program case unfairly biases the rate test toward triggering. Initial Brief, APAC, B-PA-01, 50. The logic behind this assertion is unclear, since the costs of BPA conservation as well as the savings are removed from the 7(b)(2) case. For the rate test, the 7(b)(2) customers are allocated the costs of only the amount of conservation needed to serve their loads. Armstrong BPA, E-BPA-54R, 7. For the 1985 filing, no additional resources other than Idaho Falls (i.e., no conservation) are needed to meet the loads of the 7(b)(2) customers. *See* BPA, FS-03. Therefore, no 7(g) costs or corresponding megawatts of conservation affect the 7(b)(2) case rates.

The treatment of 7(g) costs for the rate test was determined by the Legal Interpretation. The load forecast to be used to calculate rates for the rate test is described in the 7(b)(2) ROD as "the same as … the program case, except that [it] will not include estimates of programmatic conservation savings." 7(b)(2) ROD at 41. The PPC and APAC proposal is precluded from consideration here. The PPC argument to the contrary, Reply Brief, PPC, R-PP-01, 11-12, has no basis and thus cannot be considered.

The term "applicable 7(g) costs" was defined in the section 7(b)(2) Legal Interpretation as "the costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), viz, costs chargeable to 7(b)(2) customers for conservation, resource and conservation credits, experimental resources and uncontrollable events." Legal Interpretation, 49 CFR at 24000. For the 1985 rate filing rate test, the applicable 7(g) costs are comprised entirely of conservation costs. Armstrong, BPA, E-BPA-54R, 7; STR 729; STR 761. The SPM array GENOTH, as the PPC witness testifies, is made up of BPA administrative and general costs, cash lag, and expenses of the Northwest Power Planning Council, among other costs. Wolverton, PPC, STR 787; BPA, E-BPA-03A, 252-253. These costs are not applicable 7(g) costs as defined by the Northwest Power Act. The array CONSRV contains only the costs of BPA conservation programs and is thus the appropriate source of 7(g) cost data for the 1985 rate filing. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 15; BPA, E-BPA-03A, 260-263; McCullough, ICP, E-IC-16R, 3. PPC argues that "[t]here is no testimony or evidence that conservation costs have been allocated pursuant to §7(g)." Reply Brief, PPC, R-PP-01, 12. The evidence sought
[page 171] by PPC clearly exists in the definition of section 7(g) costs in the Legal Interpretation.

**Decision**

*BPA treats 7(g) costs correctly. The methods BPA uses when treating 7(g) costs are prescribed by the section 7(b)(2) Legal Interpretation and by the 7(b)(2) ROD. Since the applicable 7(g) costs for the 1985 rate filing rate test are all conservation costs, it is appropriate to use the SPM array CONSRV as a vehicle for 7(g) costs for this rate test. In addition, because no BPA* *conservation is needed as an additional resource, no 7(g) costs are allocated to the 7(b)(2) customers in the 7(b)(2) case for the 1985 rate test.*

**E. Supply Pricing Model**

The BPA Supply Pricing Model, as modified by the parties to the 7(i) proceeding for section 7(b)(2), was selected as the basis for the modeling of the rate test. 7(b)(2) ROD at 31. The SPM projects wholesale and retail power rates by simulating the ratesetting processes of BPA and its retail utility customers. For the section 7(b)(2) rate test, it projects power costs (rates) for the program case and the 7(b)(2) case for the 7(b)(2) customers for the 5-year rate test period.

PPC expresses concern that the SPM should accurately reflect the data and methodologies used in the rate filing, particularly if changes in assumptions or data were to occur as a result of the 7(i) process. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 16. BPA fully intends that the SPM should be sufficiently flexible to incorporate any assumptions or methodologies that are used in the relevant rate filing. Armstrong, BPA, E-BPA-31, l-2; 7(b)(2) ROD at 44. In addition to potential changes to the SPM itself, the data input to the SPM will be updated as necessary to incorporate changes to the pending rate proposal in assumptions or data. 7(b)(2) ROD at 39. This process was demonstrated in BPA supplemental and rebuttal testimony. Armstrong, BPA, E-BPA-32S, 1-4, and Attachments 1-3; E-BPA-54R, 14-15 and Attachment 2.

**<u>Issue #1</u>**

*Does the SPM correctly model the allocation of confirm energy to markets?*

**<u>Summary of Positions</u>**

The SPM allocates confirm energy to markets on an annual basis. The SPM allocation algorithm uses a standard deviation value that reflects the monthly deviations from the Operating Year (OY) 1939 average of nonfirm energy generation. This allows the SPM to approximate the monthly allocations of nonfirm energy from the Rate Analysis Model (RAM). Armstrong, BPA, E-BPA-32S, 3; STR 730-731.

[page 172]

PPC proposes that a monthly allocation loop be included in the SPM to approximate more closely the allocations of nonfirm energy in the Nonfirm Revenue Analysis Program (NFRAP). Wolverton, Lucas, and Spettel, PPC, E-PP-01S, 3.

The ICP disagrees with PPC's proposed changes to the SPM. McCullough, ICP, E-IC-I6R, 1-2.

**<u>Evaluation of Positions</u>**

The SPM is a simulation model. As such, it is not designed to duplicate the processes and result of BPA's ratesetting methodologies, but to approximate them as closely as possible. BPA, E-BPA-03, 9; Armstrong, BPA, E-BPA-32, 3-6. a decision must be made regarding the tradeoff between any alleged "increased accuracy of more detailed and complex modeling" and the increase in the administrative burden of operating the model and reduced understandability."

Armstrong, BPA, E-BPA-32, 8. The proposal made by PPC would increase the complexity and reduce the understandability of the SPM, with an unpredictable effect on accuracy. Armstrong, BPA, E-BPA-54R, 12. It is also unclear that the SPM's nonfirm energy allocation introduces any bias to the section 7(b)(2) rate test, since the same method is used for both the program case and the 7(b)(2) case. Armstrong, BPA, E-BPA-54, 12-13. PPC cites the impact of "secondary effects" to support its contention of different conditions in the two cases. Reply Brief, PPC, R-PP-01, 13. PPC presents no empirical analysis to support its assertion that the modeling of the rate test would be enhanced by implementing the PPC proposal. In contrast, the ICP presents evidence that changes proposed by PPC actually reduce the accuracy with which the SPM simulates BPA's ratesetting process. McCullough, ICP, E-IC-16R, 1-2. This is clearly an undesirable result.

**Decision**

*Evidence supports the SPM's allocation of nonfirm energy to various markets. The use of a standard deviation value incorporating monthly deviations from OY 1939 average nonfirm energy generation adequately accounts for the differing amounts of nonfirm energy available in all months. In addition, the simulation, rather than duplication, of the NFRAP's monthly allocations promotes ease of administration and ease of understanding.*

**Issue #2**

*Does the SPM adequately account for service to the DSIs' first quartile by sources of power other than nonfirm energy?*

**Summary of Positions**

The SPM determines expected service to the first quartile of DSI load using regional nonfirm energy generation, then treats the service as if it came solely from BPA. Armstrong, BPA, E-BPA-54R, 12; STR 741.



PPC argues that the SPM "inflates the expected amount of sales that BPA will make to the DSI top quartile." Wolverton, Lucas, and Spettel, PPC, E-PP-01, 11. PPC restates the argument by claiming that the "nonfirm power service to the DSI top quartile is overstated." Wolverton, Lucas, and Spettel, PPC, E-PP-01S, 2. *See also*, Reply Brief, PPC, R-PP-01, l4. In addition, PPC claims that the first quartile is not served entirely with nonfirm energy, and that the SPM should account for the other sources of first quartile service. Wolverton, Lucas, and Spettel, PPC, E-PP-01S, 3; Pre-Hearing Brief, PPC, P-PP-01, 6-7.

**Evaluation of Positions**

PPC's assertion that service to the DSI first quartile with nonfirm energy is overstated by the SPM is correct. The amount of overstatement approximates the amount of service BPA provides the first quartile from sources other than nonfirm energy and open market surplus energy. These other sources are flexibility, provisional draft, and Firm Energy Load Carrying Capability (FELCC) energy. Armstrong, BPA, E-BPA-54R, 11-12; STR 741. The computer code changes proposed by PPC would eliminate the overstatement of nonfirm service to the DSI first quartile.

Wolverton, Lucas, and Spettel, PPC, E-PP-01, 12. In doing so, however, the service to the first quartile from flexibility, provisional, and FELCC energy would be disregarded. Service to the first quartile, and the related expected revenues, would be understated. Armstrong, BPA, E-BPA-54R, 12. PPC expressed concern that the SPM overstates BPA non firm sales to markets other than the DSI first quartile, due to the SPM treating regional nonfirm generation as if it were sold solely by BPA. Wolverton, Lucas, and Spettel PPC, E-PP-01, 11-12. The SPM allocates nonfirm energy by a method that implicitly considers the amount of service from flexibility, provisional draft, and FELCC energy to the DSI first quartile. This method avoids the understatement of service to the first quartile that would occur if service from only nonfirm energy were considered, and does not affect the estimated service to other markets. Armstrong, BPA, STR 742. The method the SPM uses to allocate nonfirm energy responds correctly to changing load estimates. As the DSI loads decrease, the approximated level of service from flexibility, provisional draft, and FELCC energy also decreases. Armstrong, BPA, E-BPA-54R, 12. PPC proposes that the SPM algorithm that determines service to the DSI first quartile be replaced by the PPC algorithm. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 12. The result of implementing PPC's suggestion would be that the SPM would understate the total expected service to the DSI first quartile relative to the results of the rate test. a further result would be to underestimate the expected revenues from the first quartile and thus to bias the rate test results. Armstrong, BPA, E-BPA-54R, 12. PPC provided no potentially more accurate alternative to BPA's nonfirm energy allocation method.

**Decision**

*The SPM adequately determines BPA service to the DSI first quartile from nonfirm, flexibility, provisional, and FELCC energy.*

[page 174]

**Issue #3**

*Does the SPM bias the section 7(b)(2) race test by allocating costs only according to energy loads and resources?*

**Summary of Positions**

Allocation of protected costs is performed by the SPM on the basis of average energy loads. BPA, E-BPA-03, 13; Armstrong, BPA, E-BPA-32, 6.

The ICP asserts that the SPM's energy-only allocation results in a systematic underallocation of costs to the Priority Firm (PF) rate pool. This could bias the rate test toward triggering. McCullough, ICP, E-IC-11, 2-3; Pre-Hearing Brief, ICP, P-IC-01, 11-13; Initial Brief, ICP, B-IC-01, 23.

The DSIs agree with the ICP. The DSIs argue that capacity allocations should be reflected in the SPM to alleviate the SPM's "distort[ed] pool-by-pool cost allocations." Peseau, DSI, E-DS-16R, 2-3; Initial Brief, DSI, B-DS-01, 124-125.

**Evaluation of Positions**

The SPM, because of its allocation according to only energy loads, does allocate costs to rate pools differently than does the Rate Analysis Model (RAM). The SPM, relative to the RAM, allocates more Federal transmission and residential exchange capacity costs to the PF rate pool. This effect is offset by the smaller Surplus Firm Power revenue deficiency in the SPM than in the RAM. Armstrong, BPA, E-BPA-32, 6-7. The ICP cites several examples to support their allegation of systematic bias resulting from the SPM's energy-only allocation of costs. The examples -- overallocation to PF of transmission costs, underallocation of the costs of unsold surplus, and overallocation of exchange costs -- are, however, inconclusive. The ICP itself reaches conflicting conclusions in two successive answers in its direct testimony. First, "[t]he tendency of SPM to underestimate the allocation of costs to the PF rate pool, such as transmission and the costs of the unsold surplus, reduces the cost in the 7(b)(2) world." Then, "[i]n the 7(b)(2) world, the reallocation of surplus as a cost must be borne by a smaller number of customers and, thus, increases rates more in the 7(b)(2) case than in the rate case." McCullough, ICP, E-IC-11, 4. The DSIs agree with the ICP proposal "to better reflect capacity allocations in … the SPM." Peseau, DSI, E-DS-16R, 3. Neither the ICP nor the DSIs offers compelling argument or analysis supporting claims of systematic bias in the rate test caused by the SPM's energy-only allocation of costs. The inaccuracies inherent in the allocations performed by the SPM of costs that are capacity-related, as explained above, offset each other. In addition, because allocations are performed the same way for the program case and the 7(b)(2) case, any potential bias that would affect the results should be prevented. Armstrong, BPA, E-BPA-32, 7; STR 750-751.



**Decision**

*Sufficient evidence has not been provided that the SPM clearly biases the rate test by performing cost allocations on au energy-only basis. The over- and under-allocations of capacity-related costs that do occur tend to offset each other. Since the same allocation methods are used for both the program case and the 7(b)(2) case, the rate test cannot be assumed to be biased.*

**Issue #4**

*Should transmission costs be the same in the program case and the 7(b)(2) case?*

**Summary of Positions**

The SPM uses repayment data to calculate transmission costs for both the program case and the 7(b)(2) case. The 7(b)(2) case does not include amounts budgeted for transmission related to conservation and new resources. BPA, E-BPA-03, 12 and 18.

PPC is concerned that the amount of transmission-related costs is the same in both cases, when the 7(b)(2) case amount should be lower. PPC asserts that because leads [sic] in the 7(b)(2) case are lower than those in the program case, the effective transmission rate in the 7(b)(2) case is higher than it should be. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 6-7; Initial Brief, PPC, B-PP-01, 12-13; Reply Brief, PPC, R-PP-01, 8-9.

**Evaluation of Positions and Decision**

PPC is correct that the amounts of transmission costs are the same in the program case and the 7(b)(2) case, and that this results in the same amount of costs being spread over a smaller amount of loads in the 7(b)(2) case than in the program case. PPC contends that in the 7(b)(2) case BPA does not subtract, as it should, the transmission costs related to conservation and new resources. Wolverton, Lucas, and Spettel, PPC, E-PP-01, 7; Initial Brief, PPC, B-PP-01, 12-13; Reply Brief, PPC, R-PP-01, 9.

The SPM allocates the correct transmission-related costs in the 7(b)(2) case. The costs inlcuded [sic] in the 7(b)(2) case equal those in the program case because BPA plans no investment in the 7(b)(2) rate test period for transmission related to conservation and new resources. BPA's method is correct.

[page 177]

# VIII. WHOLESALE POWER RATE DESIGN STUDYRATE DESIGN STUDY

The Wholesale Power Rate Design Study (WPRDS) is the final step in the development of BPA's wholesale power rates. The costs allocated to rate classes in the COSA are adjusted to reflect BPA's rate design objectives, to comport with contractual requirements and applicable legislation, and to reflect the results of other BPA studies. In addition to the traditional rate design adjustments such as excess revenues and value of reserves, the WPRDS considers for the first time the Northwest Power Act rate directives in section 7(b)(2) for the preference customer rate limit and section 7(c)(2) for the determination of the DSI rate. Rate design also incorporates various revenue stability measures including the use of the 1939 water condition to determine excess revenues, adjusted billing determinants for computed requirements customers, and adjustment clauses.

BPA is proposing 12 rate schedules. Changes to the rate schedules include the irrigation discount in the PF and NR rates, the increased flexibility in the SP rate, and the change in the SI rate reflecting a possible 5-year contractual arrangement with the Hanna Nickel Smelting Company. The only new rate schedule, the experimental SS-85 Share-the-Savings rate, represents an alternative to the NF-85 rate for nonfirm energy sales.

## A. Rate Design Adjustments

### 1. DSI Floor Rate

**Issue #1**

*How should the DSI floor rate be determined?*

**Summary of Positions**

Section 7(c)(2) of the Northwest Power Act provides that DSI rates after July 1, 1985 shall not be "less than the rates in effect for the contract year ending on June 30, 1985." In its initial proposal, BPA anticipated that all DSI power sales made during OY 1985 would be made at the IP-83 Standard rate. BPA calculated the DSI floor rate based on a projection of the revenues that would result from the application of the IP-83 Standard rate to forecasted OY 1985 billing

determinants. Revenues received from individual DSIs due to application of the IP-83 customer charge to billing determinants greater than operating levels were excluded. The floor rate was equal to total revenues calculated according to this method, reduced by the Exchange Adjustment Clause, divided by forecasted DSI energy billing determinants during OY 1985. BPA, E-BPA-08A, 11-12; BPA, E-BPA-08, 139; Peters, BPA, E-BPA-33, 20.
[page 178]
BPA's initial proposal was prepared in the spring and summer of 1984 and did not anticipate DSI incentive rate sales during OY 1985. However, BPA implemented the DSI incentive rate for the period September 1984 through February 1985. For September through February, sales previously forecast to be made at the Standard rate were replaced with sales at the incentive rate. In BPA's supplemental proposal prepared in November 1984, the calculation of the DSI floor rate was changed so that it would not be based on a period in which incentive rate sales occurred. The DSI floor rate was calculated as the average projected IP-83 Standard rate for the remaining six months in which the incentive rate was not in effect. Because the months the incentive rate was in effect were primarily higher rate winter months, the resulting rate floor was lower. Peters, BPA, E-BPA-33S, 6.

In January 1985, BPA anticipated that a new DSI incentive rate offer would be made for the remainder of OY 1985. BPA stated that it did not intend to amend its proposal as calculated, which included average revenues for the period March 1985 through June 1985 calculated by multiplying the loads for that period as projected in November by the IP-83 Standard rate. Metcalf, BPA, TR 4654-4656. In order to gain support for the incentive rate offer, BPA indicated that it wished to preserve the supplemental proposal's floor rate method for the second incentive rate period so that the second incentive rate offer could not drive down the floor rate. Metcalf, BPA, TR 4656.

The DSIs propose that the "rates in effect" are the rates that were actually charged. Therefore, BPA should incorporate both the IP-83 Standard rate and the incentive rates that were actually charged, including all applicable charges and credits, in the calculation of the DSI floor rate. Schoenbeck, DSI, E-DS-04, 2; Initial Brief, DSI, 0-DS-01, 78-79. Another DSI floor rate proposal is described in Issue #2.

The Oregon Farm Bureau proposes that BPA use actual DSI loads and the full rate schedule for the entire operating year (OY 1985) to determine the floor rate. Ashcom, OFB, E-OF-01, 8.

OPUC/WUTC proposes calculating the floor rate as a weighted Standard rate applied to Standard rate sales. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 12-13; Initial Brief, OPUC/WUTC, B-OP/WU-01, 16-18. In its reply brief, the commissions support BPA's initial proposal floor rate of 26.8 mills/kWh. As an alternative, the commissions accept with reservations BPA's Evaluation draft decision, which uses FY 1987 billing determinants. Reply Brief, OPUC/WUTC, R-OP/WU-01, 12-14.

APAC argues that the floor rate determination should be a normalized calculation that uses projected test year billing determinants and the Standard IP-83 rate. Cook, APAC, E-PA-02S, 2-3; Initial Brief, APAC, B-PA-01, 64.

WPAG and NWU propose an alternative floor rate using the IP-83 rate schedule applied to the test year (FY 1987) billing determinants. Hutchison, et. al., NWU, E-NU-06, 1-2; Reply Brief, NWU, R-NU-01, 5; Hutchison, et. al., WPAG, E-WA-01, 64-65; Hutchison, et. al., WPAG, E-WA-01S, 6; Initial Brief, WPAG, B-WA-01, 32-33; Reply Brief, WPAG, R-WA-01, 10.

[page 179]

**Evaluation of Positions**

The calculation of the DSI floor rate incorporates three major variables. These are the rate charges in effect for the contract year ending June 30, 1985, the loads (billing determinants) to which these rates are applied, and the average revenues resulting from the application of the rates to the loads.

The DSIs are the only party to advocate the inclusion of Incentive rate billing determinants and Incentive rates in the calculation of the floor rate. They contend that the term "rates in effect" specified in section 7(c)(2) of the Northwest Power Act has a plain meaning: the actual charges at which the DSIs purchased power. Schoenbeck, DSI, E-DS-04, 2; Initial Brief, DSI, B-DS-01, 77-79.

The Administrator's Record of Decision for the 1983 Final Rate Proposal states, "Any agreement to adopt an alternate (Incentive) rate will include language stating that the floor rate will not be based on such an alternate rate." BPA, 1983 Rates ROD, 268. Such language was also included in both the Record of Decision on Implementation of the IP-83 Industrial Incentive Rate and in the DSI Incentive rate contracts. Peters, BPA, E-BPA-33, 23-24; BPA, Implementation of the IP-83 Industrial Incentive Rate, Administrator's Record of Decision, 28-29; Initial Brief, NWU, B-NU-01, 21-26. The argument made by the DSIs to include revenues from Incentive rate sales in the calculation of the floor rate disregards BPA's stated intention not to base the floor rate on the Incentive rate.

BPA's exclusion of Incentive rate loads and revenues from the calculation of the floor rate in the supplemental proposal is consistent with BPA's intent with respect to the floor rate. The reason for such an exclusion is two-fold. First, BPA determined that broad customer support was necessary for a special rate such as the Incentive rate to work. Second, BPA attempted to provide protection to its non-DSI customers from any potential long-term harm from a special short-term DSI rate that was not based on costs. BPA, 1983 Rates ROD, 267-268; Peters, BPA, E-BPA-33, 23-24. Virtually all other parties agree with BPA that the Incentive rate revenues should not be included in the calculation of the floor rate. Cook, APAC, E-PA-10R, 2, 5; Hutchison, et. al., NWU, E-NU-06, 2; Hutchison, et. al., NWU, E-NU-06S, 3; Initial Brief, NWU, B-NU-01, 13, 16-19; White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 12; Initial Brief, OPUC/WUTC, B-OP/WU-01, 15-16; Hutchison, et. al., WPAG, E-WA-01S, 7; Initial Brief, WPAG, B-WA-01, 32.

The parties that agree to eliminate Incentive rate sales from the floor rate calculation, however, disagree strongly with BPA’s treatment of the 6-month period from September 1984 through February 1985, during which Incentive rate sales were made. BPA excluded all Incentive rate loads and revenues during that period from the calculation of the rate floor as presented in supplemental testimony. In supplemental testimony, WPAG, APAC, and NWU

claim that the practical effect of BPA's approach is to lower the DSI floor rate, thereby violating the assurances given by the Administrator in both the 1983 Rates ROD and the Industrial Incentive Rate ROD that the
[page 180] incentive rate would not affect the floor rate. By eliminating incentive rate sales, which occur predominantly in winter months, the floor rate is based only on summer Standard rate sales. As a result, the supplemental proposal floor rate is lower than in BPA's initial proposal, which assumed no incentive rate sales and was therefore based on both winter and summer Standard rate sales. These customers claim that BPA is ignoring the "hold harmless" provisions of the 1983 Rates ROD, the Industrial incentive Rate ROD, and the Incentive rate contracts. Initial Brief, NWU, B-NU-01, 19-20; Hutchison, et. al., NWU, E-NU-06S, 6-7; Cook, APAC, E-PA-02S, 2; Initial Brief, APAC, B-PA-01, 65-68; Hutchison, et. al., WPAG, E-WA-01S, 7.

In light of the stated purpose of the DSI floor rate, which is to ease the transition from cost-based to equity-based DSI rates, certain arguments are worthy of careful consideration. First, inclusion of the incentive rate loads and revenues in the calculation of the floor rate would lower the floor rate, thereby potentially harming BPA's non-DSI customers in the transition from cost-based to equity-based DSI rates. BPA's initial and supplemental proposals attempted to exclude the incentive rate from the calculation of the floor rate. The seasonal nature of the rates, however, caused the floor rate calculation to be lower than it would have been had more winter loads entered into the calculation. In response to BPA's supplemental proposal, the non-DSI customers provided several arguments against BPA's proposal to exclude Incentive rate sales for the 6-month period.

Several parties object to BPA's method of eliminating the 6-month Incentive rate period on the grounds that the period for which BPA calculates the floor rate becomes too short. APAC points out that section 7(c)(2) states that the floor rate is to be based on the rates in effect for a full year. Initial Brief, APAC, B-PA-01, 66. Also, APAC contends that normal ratemaking procedures require a full 12 months of data. Initial Brief, APAC, B-PA-02S, 2. NWU, APAC, and WPAG each describe a potential outcome of BPA's elimination of incentive rate sales. In an extreme case, had BPA sold DSI power at Incentive rates for the entire period, the floor rate would be zero. Hutchison, et al., NWU, E-NU-06S, 7; Initial Brief, NWU, B-NU-01, 20; Hutchison, et al., WPAG, E-WA-01S, 7. BPA shares this concern that the Incentive rate not be based on too short a time period. Metcalf, BPA, TR 4655.

NWU extends this time related argument to costs. The NWU argues that section 7(c)(1)(A) requires the floor rate to be cost based. NWU points to BPA's description of the floor rate test as "a means to smooth the transition from (1) a DSI rate based on the cost of resources plus the net cost of the exchange not recovered from other customers to (2) a DSI rate equitable in relation to the retail prices paid by industrial customers served by BPA's preference customers. By establishing a minimum level for the DSI rate, the floor rate test constrains the impact on BPA's other customers caused by the change in methodology for establishing the post-1985 DSI rate." Initial Brief, NWU, B-NU-01, 26-27. Thus, the purpose of the floor rate is to protect BPA's non-DSI customers from the impact of a sudden drop in the DSI rate. If the DSI equity-based rate were less than the previous cost-based floor rate, the floor rate would be deemed to be the IP rate. In NWU's view, by excluding [page 181] the higher cost winter months, the floor rate calculation is not fully cost-based. The floor rate must be based on an entire year of cost-based Standard rate sales. Initial Brief, NWU, B-NU-01, 26-27.

The parties offer several solutions to the inadvertant [sic] effects of eliminating incentive rate sales from the calculation of the floor rate. APAC provides two proposals, related in that each forecasted loads do not include Incentive rate sales. In supplemental testimony APAC proposes to apply Standard IP-83 charges to BPA's October forecast of billing determinants. Cook, APAC, B-PA-02S, 3. In its initial brief, APAC proposes to calculate the floor rate by applying the IP-83 charges to billing determinants forecasted for the DSIs during the development of the IP-83 final proposal. This yields 26.8 mills/kWh excluding the 1.8 mill/kWh VOR credit. Cook, APAC, B-PA-01, 67.

OPUC and WUTC propose a method to remove the temporary effects of the aluminum market and possible induced shifts in use caused by the incentive rate. They would develop weighted average rates assuming constant DSI loads over the year. As an alternative, seasonal weights over a 3-year period during which no incentive discounts were offered should be used. This would be much like BPA's approach to calculating the 7(c)(2) margin. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 12-13; Initial Brief, OPUC/WUTC, B-OP/WU-01, 16-18. A third proposal is put forward by OPUC/WUTC and WPAG. For other customers to be held harmless, they propose an "application of the IP-83 rate to the DSI loads which BPA would have served without the incentive rate offer." Hutchison, et al., WPAG, E-WA-01S, 6-7; White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 13. To follow this approach consistently and completely, the loads during OY 1985 would have to be forecast assuming an IP-83 Standard rate for the entire period.

NWU and WPAG both propose to apply the IP-83 Standard rate to test year billing determinants. Hutchison, et. al., NWU, E-NU-06, 1-2; Reply Brief, NWU, R~NU-01, 5; Hutchison, et. al., WPAG, E-WA-01, 64-65; Hutchison, et. al., WPAG, E-WA-01S, 6; Initial Brief, WPAG, B-WA-01, 32-33; Reply Brief, WPAG, R-WA-01, 10. The use of test year billing determinants obviates the need for resolution of the controversy regarding which particular loads from OY 1985 would be appropriate in the calculation of the floor rate. As an alternative, however, NWU supports BPA's initial proposal floor rate of 26.8 mills/kwh. Initial Brief, NWU, B-NU-01, 28. The commissions agree the use of FY 1987 billing determinants (BPA's draft decision) is an acceptable alternative. They have, however, two reservations about this technique: (1) the floor rate should not be allowed to change from rate period to rate period, and (2) the FY 1987 loads used should be the last billing determinants previously documented in the record. Reply Brief, OPUC/WUTC, R-OP/WU-01, 12-14.

It is clear from section 7(c)(2) of the Northwest Power Act that the floor is to be based on the IP-83 rate schedule. Accepting NWU and WPAG's proposal, the IP-83 rate schedule can be compared to the IP-85 rate schedule by applying both to test year billing determinants. The following two revenue calculations would be compared: (FY 1987 loads IP-83 rates) and (FY 1987 loads IP-85 rates). This methodology resolves any arguments about whether [page 182] exclusion of incentive sales in the winter produces a seasonal bias that unintentionally lowers the floor rate. It also renders moot the arguments as to whether to include or exclude incentive rate revenues from the floor rate calculation. Furthermore, the use of test year billing determinants allows the direct comparison of the IP-83 and IP-85 rate schedules. This comparison can be made because the test year loads can be factored out of both sides of the equation. Using the IP-83 rate schedule applied to test year billing determinants would allow BPA to change rate designs from one rate filing to another and still have an unbiased floor rate test.

Comparison of the IP-83 Standard rate to the IP-85 Standard rate by application of each to test year (FY 1987) loads is superior to the various proposals that advocate the use of a single year's average rate. For instance, the use of average rates for OY 1985 runs the risk of short-term aberrations in DSI economics and load patterns, which have the potential to swing the floor rate, a rate which may be in effect for many years. If the Incentive rate had not been implemented, DSI loads might have decreased and revenues from the IP-83 customer charge would have caused average DSI revenues to be much higher than anticipated. In fact, absent the incentive rate offers, the DSIs could have manipulated OY 1985 average revenues simply by taking maximum loads in the summer period and curtailing during the winter. Any floor rate test which uses loads that have been fixed in a single year is not logical because of the permanence that would be embodied in the floor rate as a result of the aberrations inherent in that fixed set of loads. It is therefore more appropriate to assume that a floor rate test should be based on the application of the IP-83 rate schedule to a set of loads which normalize aberrations pertaining to seasonality, sales at the incentive rate, the effects of the customer charge on revenues, and other peculiarities indicated in arguments made by the various parties. Such loads which have these aberrations removed are the *projected* loads from the test year.

The *IP-83 rate schedule* represents the rates in effect: that is, the Standard rate which was based on section 7(c)(1)(A) of the Northwest Power Act. Applying that rate schedule to test year loads will allow consistency in the floor rate test while accounting for changes in projected DSI load shape and load factors.

The DSIs propose contradictory arguments with respect to the calculation of the DSI equity-based rate and the floor rate. They argue that the applicable wholesale power rate for calculating the DSI equity-based rate is the Priority Firm *rate schedule*. Simultaneously, they argue that the floor rate is an *average rate* amount. The calculation of the DSI equity-based rate and the floor rate should be consistent, using the *rate schedules* for determining both rates.

**<u>Decision</u>**

*The floor rate calculation is based on the IP-83 rate schedule applied to test year (FY 1987 for this rate filing) billing determinants. This method is consistent with the language in section 7(c)(2) of the Northwest Power Act,*
[page 183] *which requires that the floor rate be based on the rates in effect for the contract year ending June 30, 1985. This method also assures that the floor rate will not be based on the OY 1985 incentive rate sales. Finally, this method of using test year loads allows BPA to change its rate design in subsequent rate filings and yet maintain an unbiased floor rate test.*

**<u>Issue #2</u>**

*Should BPA make adjustments to the IP-83 rates used in calculating the floor rate?*

**Summary of Positions**

BPA's proposals for calculating the floor rate contain two adjustments to the IP-83 rate schedule. The first of these adjustments concerns the Incentive rate. This adjustment was discussed earlier. The second concerns BPA's decision to exclude revenues received from individual DSIs due to application of the IP-83 customer charge to billing determinants greater than operating levels. The DSIs propose that should BPA determine to exclude Incentive rate effects, then BPA must consider and exclude certain other costs from the IP-83 Standard rate. The DSIs claim that these adjustments should be made because: (1) costs included in the IP-83 rate have been shifted into the contract year ending June 30, 1985, from other periods; (2) such costs were not anticipated by Congress when the DSI floor rate provisions were enacted; and (3) such costs were not properly allocable to the DSIs, although included in the IP-83 Standard rate. For these reasons, the DSIs believe that such costs adversely affect the floor rate calculation by not affording the DSIs the rates Congress intended. The specific items that the DSIs claim should be excluded from the IP-83 Standard rate are:

1. ASC deemers;
2. deferral;
3. Implementation of new ASC methodology;
4. proper allocation of excess revenue; and
5. unsold surplus power revenue deficiencies.

Schoenbeck, DSI, E-DS-04, 4-5; Initial Brief, DSI, B-DS-01, 84.

BPA responded to the DSIs' proposal by including two adjustments: (1) implementation of the new ASC methodology, and (2) elimination of the costs of the deferral on the IP-83 Standard rate. BPA, Evaluation, A-01, 253.

PPC argues that the DSI proposal is illegal and discriminatory. PPC urges that DSI rates should not be set as if BPA had perfect foresight in all
[page 184] instances. The rates of BPA's other customers do not enjoy such considerations. Wolverton, et al., PPC, E-PP-04R, 13.

Both WPAG and NWU disagree with the DSIs' proposal. Had Congress intended a the floor rate to be adjusted for occurrences such as the deferral or the full implementation of the new ASC methodology, section 7(c)(2) would have specifically included adjustment provisions. Reply Brief, WPAG, R-WA-01, 10-11; Reply Brief, NWU, R-NU-01, 6.

APAC argues that the DSI proposal violates a basic ratemaking principle, the prohibition against retroactive ratemaking. Cook, APAC, E-PA-10R, 1. The cost items that BPA and the DSIs propose to eliminate from the calculation of the floor rate have been previously found by the Administrator to be properly included in the IP-83 Standard rate. Therefore, these costs should not be eliminated. Reply Brief, APAC, R-PA-01, 22-23.

APAC also disagrees with BPA's proposal to eliminate amounts that would be collected under the customer charge provision in the IP-83 rate schedule beyond the level of a demand charge. APAC claims that the IP-83 customer charge is an integral component of the IP-83 rate, and without it the IP-83 demand and energy charges would be different. Thus, APAC argues, all revenues from the IP-83 rate should be included in the floor rate calculation. Cook, APAC, E-PA-02, 26-28; Cook, APAC, E-PA-02S, 2-4; Initial Brief, APAC, B-PA-01, 67-68.

**Evaluation of Positions**

APAC proposes to include revenues from application of the IP-83 customer charge to billing determinants greater than the operating level. Cook, APAC, E-PA-02, 26-28; Cook, APAC, E-PA-02S, 2-4; Initial Brief, APAC, B-PA-01, 67-68. This issue is rendered moot by the decision to apply the IP-83 Standard rate to the test year loads. In any case, the APAC proposal is inconsistent with the purpose of the floor rate. It would have the potential of raising the floor rate significantly because of a provision in the IP-83 rate designed to moderate short-term load and revenue savings.

The DSIs argue that since BPA has adjusted the IP-83 rates to remove the effects of the Incentive rate, the IP-83 rate should be adjusted in consideration of other factors. They argue that the IP-83 rate used in the floor rate calculation should be adjusted to remove the effects of certain costs and methodologies used in a prior ratemaking process, which they believe are contrary to the rate protection that Congress intended by providing the floor rate. Schoenbeck, DSI, E-DS-04, 4-5; Schoenbeck, DSI, E-DS-04S, 1-3; Initial Brief, DSI, B-DS-01, 77-78, 87-97. The DSIs support BPA's initial decision to eliminate the effects of the deferral and to include the full implementation of the new ASC methodology. This action is appropriate because in the period the floor rate comes into effect the deferral costs will have been fully recovered and the new ASC methodology will be fully implemented. To continue to collect these costs would result in a "perpetual windfall" for BPA's other customers. BPA should also recognize the remaining costs the DSIs
[page 185] have outlined, that arise from similar nonrecurring or extraordinary events. Reply Brief, DSI, R-DS-01, 46-54.

APAC argues that the Record of Decision in the 1983 rate filing attempted to define and support the Administrator’s reason for adopting each component included in the IP-83 rate. The 1983 Rates ROD contains no special consideration for the various cost components of the IP-83 rate such as deferral costs. APAC points out that, although rates may not be based on perfect information, they cannot be adjusted retroactively to match actual cost incurrence or actual use. Cook, APAC, E-PA-10R, 5. The PPC agrees, concluding that BPA should not exclude the items suggested by the DSIs in calculating the floor rate. They suggest that unforeseen events will always affect BPA's rates. Such events are a regular and usual part of utility ratemaking. Wolverton, et al., PPC, E-PP-04R, 14.

APAC and the PPC are correct that ratemaking is not a perfect science and that retroactive ratemaking is not common practice. Setting the floor rate, however, does not involve retroactive ratemaking. Rather, it involves the application of the results of historical events to develop future rates, much like the use of a historical test year to set prospective rates. APAC and NWU take exception to this analogy. APAC contends the floor rate calculation applies a historical rate, not historical events. Reply Brief, APAC, R-PA-01, 24. NWU contends BPA's analogy constitutes sophistry. Historical costs may be normalized, but not historical rates. Reply Brief, NWU, R-NU-01, 6-7. Neither APAC's distinction between a rate and an event nor NWU's distinction between historical cost data and historical rates are persuasive. Rates are comprised of costs and rates are themselves an event. APAC, NWU and PPC all overlook the major point that it is common ratemaking practice to review historical test year events to eliminate those that are nonrecurring or extraordinary when setting future rates. Moreover, BPA, PPC, NWU and other parties argue that "rates in effect" should not include the IP-83 incentive rate. This argument must be premised on consistent logic. APAC, for instance, admits that the incentive rate is unique. Reply Brief, APAC, R-PA-01, 23. The parties then urge the Administrator to ignore the incentive rate in calculating the floor since the incentive rate is unique. This logic justified the contractual provisions by which the Administrator obtained waivers from the DSIs that the floor rate would not be based on the incentive rate. It is the same logic which drives the Administrator to examine other aspects of the IP-83 rate schedule.

Ample precedent exists for this view. For example, the Federal Energy Regulatory Commission, in its regulations under the Natural Gas Act, has adopted the following rule concerning costs incurred during a 12-month test period:

> The 12 months of experience shall be adjusted to eliminate nonrecurring items (except minor amounts), but this shall not preclude the filing company from including items which, on the basis of existing facts, it can show will be experienced or from including an appropriate normalizing adjustment, e.g., rate case expenses, in lieu of a nonrecurring item.



18 CFR 154.63(e)(2). As a Commission Administrative Law Judge explained, "'The purpose of this rule is to prevent a company from overrecovering its expenses by including excessive amounts in its test period figures and continuing to collect rates based on those figures indefinitely." *Distrigas of Massachusetts Corporation*, Docket No. RP79-23-003, 18 FERC ¶63,036, 65,119.

There are other examples. See, for instance, the Commission's Uniform System of Accounts. WPAG argues that BPA should not rely on the Commission's Uniform System of Accounts on the grounds that the Commission's system has no application to the floor rate nor do those regulations have the force of law. Reply Brief, WPAG, R-WA-01, 11. The floor rate is an unique provision in the Northwest Power Act, and there is little legislative guidance as to how the floor rate should be implemented. *See* Reply Brief, NWU, R-NU-01, 6. In such a case, Commission rules certainly can guide BPA as to what standard ratemaking practice might be. The historical test year analogy is the most appriopriate [sic] guidance available. Account 188, for instance, covering research, development and demonstration expenditures, provides:

> C. In certain instances a company may incur large and significant research, development and demonstration expenditures which are nonrecurring and which would distort the annual research, development, and demonstration charges for the period. In such a case the portion of such amounts that cause the distortion

> may be amortized to the appropriate operating expense account over a period not to exceed 5 years unless otherwise authorized by the Commission.

18 CFR 101.188. The purpose of such provisions is to prevent distortion of future rates based on nonrecurring or extraordinary events during a test year. It is such reasoning that has led BPA to agree that incentive rate sales should be excluded from the determination of the floor rate in order to prevent long term harm to BPA's non-DSI customers. likewise, it is appropriate to examine the IP-83 rate structure to determine if any components might provide BPA's non-DSI customers a perpetual windfall. As NWU observes, the floor rate was designed to be a bridge between cost-based DSI rates and equity-based DSI rates. Initial Brief, NWU, B-NU-01, 9-10. This position does not invite a windfall to non-DSI customers.

It is not relevant that BPA did not decide the issue of adjustments to the IP-83 rate for the purposes of the floor rate determination during the 1983 rate case. BPA did, in fact, reach one floor rate determination that considered the role of the incentive rate. It is significant, however, that BPA determined that the remaining issues regarding the floor rate would be deferred until the 1985 rate case. BPA, 1983 Rates ROD, 268. The relationship between the incentive rate and the floor rate was determined to be important to the *implementation* of the IP-83 rate schedule. For that reason, it was included in the 1983 Rates ROD. The other issues proposed by the DSIs appropriately are addressed in this rate adjustment proceeding.
[page 187]
In the case of the floor rate, the intent of the legislation also must be taken into account. For instance, NWU attacked BPA's initial proposal because it "violates the intent of the section 7(c)(2) floor rate provision." Initial Brief, NWU, B-NU-01, 26. NWU urges:

> C. The purpose of the floor rate is to *smooth the transition* from cost-based DSI rates in effect until June 30, 1985 to an equitably based rate in effect from July 1, 1985 and there after (emphasis added).

Initial Brief, NWU, B-NU-01, 9.

In its reply brief, however, NWU states, "One searches the Regional Act in vain for Congressionally mandated smoothness. One surmises, in fact, that 'smoothness' is no test at all." Reply Brief, NWU, R-NU-01, 9. This example demonstrates one of the many in consistencies that appear in NWU's arguments.

NWU has also urged that the purpose of the floor rate was to protect "non-DSI customers from the rate shock that would result from such a abrupt shifting of revenues." Initial Brief, NWU, B-NU-01, 10. If such were the purpose of the floor rate, then the purpose has been achieved. The average PF-85 rate is very close to the average PF-83 rate. NWU now urges that, "just as a rose is a rose, rates in effect means rates in effect. The statute allows for not more inquiry than that." Reply Brief, NWU, R-NU-01, 6. If NWU is correct, then BPA is not permitted to pick and choose among rates in effect in order to exclude the incentive rate from calculation of the floor rate. Furthermore, if NWU is correct, then BPA was not justified in contractually requiring the DSIs to waive their rights to a floor rate set on "rates in effect" by excluding incentive rate sales. The logic of NWU's argument is that such a waiver may have been unlawful. NWU cannot urge BPA to reject one floor rate methodology because it violates the intent of section 7(c)(2) (Initial Brief, NWU, B-NU-01, 26) and then argue that BPA has no authority to inquire into the meaning of the statute. Reply Brief, NWU, B-NU-01, 6. BPA rejects such ill-founded logic.

In this light, some of the DSI proposals have merit; namely, the adjustments for the deferral and the phase-in of the new ASC methodology. The treatment of the deferral was an unusual attempt by BPA to recover in its 1983 rates the unrecovered costs from previous rate filings. As a result, the 1983 rates were increased for previously unrecovered costs. It would be unfair to the DSIs to incorporate these costs in post-85 rates by using an IP-83 rate that has not been adjusted to account for the effects of the deferral. Initial Brief, DSI, B-DS-01, 87-88; Reply Brief, DSI, R-DS-01, 46. NWU says that because it is possible for BPA to incur a deferral in any given rate period, the deferral is not a nonrecurring event. Reply Brief, NWU, R-NU-01, 8. NWU is correct that the potential for incurring a deferral is always present. In normal practice, however, BPA does not assume it will have a deferral at the end of a rate period that will have to be recovered in subsequent rate periods. Metcalf, BPA, TR 4593. Thus, the deferral in 1983 was an unusual event. Other utilities object to adjusting the IP-83 rate by [page 188] arguing the deferral was caused by the DSIs or the deferral was the responsibility of the DSIs. Reply Brief, APAC, R-PA-01, 25; Reply Brief, WPAG, R-WA-01, 11. Allocation of the deferral was an issue resolved in the 1983 rate case. Arguments that the DSIs should have been allocated more of the deferral in that rate case do not justify collection from them multiple times the amount that was allocated to them by including it in the floor rate. Regardless of the source or responsibility of the deferral, the deferral remains an unusual event. Therefore it is improper to allow the costs of the deferral to remain in the IP-83 rate for purposes of calculating the floor rate.

The phase-in of the new Average System Cost methodology is also an unusual event that unduly affects the average 1983 DSI rate. In this case, as the DSIs contend, the phase-in of the new ASC methodology is a short-term measure to avoid a sudden large increase in retail rates. The long-term effect of this phase-in should be eliminated for the same reason the Incentive rate sales were excluded from the floor rate. The phase-in is a short-term measure adopted to benefit other customers. The DSIs claim that it would be unfair to eliminate the Incentive rate from the calculation of the floor rate without also eliminating the impacts of the ASC methodology phase-in. Initial Brief, DSI, B-DS-01, 88-90; Reply Brief, DSI, R-DS-01, 46. With regard to the transition from pre-1985 to post-1985 rate directives, the new ASC methodology will be fully implemented by July 1, 1985, at a time when the floor rate test will be in effect. If the IP-83 rate were not adjusted for the new ASC methodology, DSI rates would be held artificially high, thereby preventing a smooth transition to post-85 DSI rates.

Several utilities oppose the deferral and ASC phase-in adjustments to the IP-83 rate on the grounds that these adjustments are not specifically stated in section 7(c)(2). Reply Brief, NWU, R-NU-01, 6; Reply Brief, WPAG, R-WA-01, 10-11. This argument is without foundation. Since the deferral and ASC phase-in adjustments are extraordinary or nonrecurring events, Congress could not have anticipated them in writing the Northwest Power Act. Some interpretation of legislative directives is required to address the impacts of these aberrations.

The DSIs advanced several other proposals to adjust the IP-83 rate. The ASC deeming provisions, surplus power adjustments, and allocation of excess revenue, unlike the deferral and ASC methodology phase-in, are not one-time adjustments. The DSIs argue that the balances collected in the deemer accounts shift the collection of those revenues from the present to the future and that those balances should be used to offset the floor rate. Initial Brief, DSI, B-DS-01, 85-87. There are three basic flaws to this argument. First, those balances may never be collected. Peters, BPA, TR 4577. Thus, an adjustment based on these balances would be hypothetical. Second, it is unclear that the deeming utilities would have signed exchange contracts if the deeming provision had not been included. An additional hypothetical circumstance is thus invoked. Third, the deemer clause will continue to be a part of the post-1985 ratemaking procedure. It is thus a part of both pre-1985 and post-1985 rates.

[page 189]

Similarly, BPA continues to forecast that not all surplus sales will be sold at the fully allocated costs, as happened in the 1983 rate case. The DSIs contend that BPA's reasoning that no adjustment is necessary for surplus power costs included in the IP-83 Standard rate because it is a recurring event fails to recognize that an "extraordinary" cost need not be based on a nonrecurring event. Reply Brief, DSI, R-DS-01, 48. BPA's other customers argue the DSIs are not entitled to rate floor protection for cost levels which are extraordinarily higher in the IP-83 Standard rate than are expected to occur any time after 1985. The DSIs contend that the IP-83 Standard rate contains an extraordinarily high *level* of surplus power costs, and that such costs will decline in the future. Reply Brief, DSI, R-DS-01, 49. Failure to make an adjustment, claim the DSIs, will provide a windfall to the non-DSI customers. They urge that the rate floor be reduced by 1.3 mills/kwh to reflect the expected level of unsold surplus in the coming rate period. Initial Brief, DSI, B-DS-01, 92.

There is no certainty that unrecovered costs of surplus power will decline. In the 1983 rate filing, of 1211 MW of surplus power available, BPA assumed that 700 MW would be sold. Thus, 511 MW were assumed to be associated with unrecovered surplus power costs in OY 1985. In FY 1986, of 1700 MW of available surplus, BPA assumes that 1090 will be sold. In FY 1987, of 1427 MW of available surplus, BPA assumes that 1090 MW will be sold. Therefore in FY 1986, there are 610 MW of surplus power associated with unrecovered surplus power costs, and the amount of such power for FY 1987 is 337 MW. Both the availability and the marketability of surplus power is subject to a great deal of uncertainty. BPA therefore should not accept the DSI argument that the level of unrecovered exchange costs will decline with any degree of certainty.

It is likely that the DSIs will not be allocated as large a share of those costs as they were in the 1983 rate case. But that is a consequence of the change in the DSI rate directives. The 1983 rate case allocation resulted from the DSIs' responsibility under section 7(c)(1)(a) for exchange costs not allocated to other customers.

Incorporation of the Miller decision in the nonfirm energy rate (see Section I) involves a change in cost allocation rather than an extraordinary cost item. The DSIs claim that a lower level of exchange costs should be assumed in the IP-83 Standard rate for determination of the floor rate as a result of the Miller decision. They claim that these exchange costs will be nonrecurring in post-85 firm power rates and thus nonrecurring insofar as the rate floor calculation is concerned. The DSIs state that they should not be penalized through a high floor rate because IP-83 rates were inappropriately high. Reply Brief, DSI, R-DS-01, 51. Further, no specific order from the Federal Energy Regulatory Commission or any court requires BPA to recalculate the DSI rates retroactively as a result of the Miller decision and make rate adjustments to correct any errors in subsequent rate filings. It is a relatively straightforward calculation to adjust the IP-83 rate to remove the effects of the deferral and the phase-in of the new Average System Cost methodology; such changes merely adjust costs. To adjust the IP-83 rate to reflect excess revenues under conditions that are different from the ones [page 190] assumed in the rate filing would reopen virtually all decisions made in arriving at the 1983 rates. At the very least the forecast of nonfirm sales would have to be changed. This would be inappropriate for the limited purpose of determining the DSI floor rate in the 1985 rate filing.

**Decision**

*Customer charge revenues derived from application of the charge to billing determinants above billing demands are not included because the customer charge was intended to moderate short-term revenue swings, not increase the DSI rate for years to come. The floor rate has been further adjusted to remove the effects of the deferral and the new Average System cost methodology. The floor rate protects BPA's other customers from a decline in the DSI rate caused by the change in ratemaking methodology. It protects the DSIs from having to pay for many years the extraordinary, nonrecurring deferral and exchange costs included in the IP-83 Standard rate.*

**Issue #3**

*Should the floor rate be adjusted for the value of reserves (VOR) credit?*

**Summary of Positions**

BPA's calculation of the floor rate results in a floor rate that has not been reduced by a value of reserves credit. BPA, E-BPA-08A, 11-13; BPA, E-BPA-08, 43, 139; Peters, E-BPA-33S, 6-7, Attachment 2, 1. This floor rate is compared to a margin-based rate that has not been reduced for VOR credit. In comparision [sic], if the floor rate is higher than the margin-based rate, then the floor rate is reduced by the VOR credit and becomes the effective DSI rate. If the margin-based rate is higher than the floor rate, the margin-based rate is reduced by a value of reserves credit and becomes the effective DSI rate.

The DSIs argue that the floor rate used in the comparision [sic] with the margin-based rate should be reduced by the value of reserves credit included in the IP-83 rate schedule prior to the comparison. This floor rate would then be compared to the margin-based rate which has not been reduced by a VOR credit calculated for current rates. Schoenbeck, DSI, E-DS-04, 5, Schedule 1, Schedule 2; Schoenbeck, DSI, E-DS-04S, Schedule 4; Initial Brief, DSI, B-DS-01, 95-97; Schoenbeck, DSI, TR 4519-4520. If the floor rate is higher, it is then reduced by the VOR credit applicable to the current rates and becomes the effective DSI rate. If the margin-based rate is higher, it would be reduced by the VOR applicable to the current rates, and would become the effective DSI rate. Initial Brief, DSI, B-DS-01, 95-97.

**Evaluation of Positions**

The DSIs maintain that the rates in effect are those rates that they Actually paid in OY 1985. The DSIs received a VOR credit in their effective
[page 191] rates during OY 1985. The DSIs argue that the IP-83 VOR credit should be incorporated in the floor rate, and if the floor rate is the effective post-1985 rate, it should then be adjusted further for a VOR credit applicable to the current rate. Initial Brief, DSI, B-DS-01, 96.

They argue that BPA has calculated "a floor rate which is higher than any rate in effect during CY 1985" (emphasis in original). This, they claim, resulted from not recognizing the VOR credit in the IP-83 rate in the calculation of the floor rate. Initial Brief, DSI, B-DS-01, 96. They claim that BPA did not recognize the VOR credit a rising from CY 1985 in the floor rate calculation because BPA believes that doing so amounts to inappropriate "double counting" of the reserve credit. They conclude that this concern is unfounded. They argue that the floor rate can only increase the charges to the DSIs; it cannot reduce the charges so as to result in an excessive reserve credit. Initial Brief, DSI, B-DS-01, 96. They conclude their argument by citing the intent of Congress, as stated in Appendix B:

> The rate will be set *at a level no less than that set for the year 1984-85* [the rate floor] and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers… The rate is *then* adjusted for reserves.

S. Rep. No. 272, 96th Cong., 1st Sess., Appendix B, 59 (1979) (emphasis supplied by DSIs).

The issue raised by the DSIs revolves around the fact that the floor rate is calculated before, not after, it is determined to be the effective current rate. The computation of the floor rate should be comparable to the computation of the margin-based rate with which it is compared. The margin-based rate is calculated as the margin, based on priority firm billing determinants, added to the priority firm rate. The margin therefore does not take into account a VOR credit. In order for a comparison of like quantities to be made, the floor rate also should not take into account the VOR credit. Once the comparison is made, the effective current rate for the DSIs is determined. At this point, it is proper to take into account a VOR credit that adjusts the effective DSI rate.

**Decision**

*Both the floor rate and the margin-based rate are calculated without accounting for a VOR credit. The current VOR credit is applied to the current effective rate once that rate has been determined. This methodology complies with the language of section 7(c)(2) and section 7(c)(3) of the Northwest Power Act, and is consistent with the purpose of the floor rate.*
[page 192]

## 2. Test Year and Scaling

**Issue #1**

*Should FY 1987 be the test year?*

**Summary of Positions**

BPA has selected FY 1987 as the test year within the 27-month rate period. Parker, BPA, E-BPA-24, 2-4. OPUC/WUTC recommends the use of FY 1986. Rolseth and White, OPUC/WUTC, E-OP/WU-01S, 1-5.

**Evaluation of Positions and Decision**

BPA uses fiscal year data in its ratesetting process in order to be consistent with its budget period. Cost data for both FYs 1986 and 1987 are used in the process of scaling to set test period rates. Parker, BPA, E-BPA-24, 3. Because of scaling, therefore, the choice of fiscal year will not result insignificant changes to the final rates. The choice of FY 1987 as the test year is based on its proximity to the end of the rate period, when changes that might otherwise result in a new filing can be incorporated into the current process. OPUC/WUTC advocates a FY 1986 test year. They cite cost revisions contained in BPA's supplemental proposal as evidence that FY 1987 forecasts are subject to greater error than the FY 1986 forecasts. Rolseth and White, OPUC/WUTC, E-OP/WU-01S, 3. The revisions affect FY 1987 more than FY 1986 not because of increased error, however, but because of the timing of expenditures. The most notable example of this is the Supply System costs, which were reduced in the supplemental proposal by $40.7 million in FY 1986 and $151.1 million in FY 1987. Kallio, BPA, E-BPA-17, 7; Kallio, BPA, E-BPA-17S, 1-2. Therefore, because of its proximity to the end of the test period, FY 1987 is used in the final proposal.

**Issue #2**

*Should the cost and revenues for the final 3 months of FY 1985 be included in the scaling process?*

**Summary of Positions**

BPA's current scaling method is based on FYs 1986 and 1987 only; the last 3 months of FY 1985 are not included. BPA, E-BPA-08, 40-46. The Joint Parties propose the inclusion of those three months to avoid overcollection of revenues. Wolverton, et al., Joint Parties, E-JP-01, 14-18.

**Evaluation of Positions**

The proposal to exclude FY 1985 revenues from the ratesetting process is based on the difficulties involved in determining the appropriate level of
[page 193] costs for a relatively minor portion of the fiscal year. Any method of distributing FY 1985 costs into the last 3 months would be arbitrary. Parker, BPA, E-BPA-24, 5; Parker, BPA, TR 3500-07. The Joint Parties propose to add one-fourth of the difference between FY 1987 and FY 1985 revenue requirements to the scaling process. Wolverton, et al, Joint Parties, E-JP-01, 17. They justify the use of 25 percent of fiscal year costs by claiming that "several costs …

occur on a regular basis." Initial Brief, Joint Parties, B-JP-01, 20. This statement is in sufficient to conclude that 25 percent would be a representative proportion of costs in the last 3 months of the fiscal year. The Joint Parties also maintain that BPA's case is weakened by acknowledging the existence of revenue forecasts for the three months in question. Reply Brief, Joint Parties, R-JP-01, 22-24. The issue is not the ability to forecast revenues, but the ability to estimate revenue requirements. BPA's projected revenues in a three-month period are not an accurate proxy for the revenue requirement in the same time period. Furthermore, the current proposal contains rate levels that are comparable to current rates, which will minimize any variance of revenues collected during the 3 months in question.

**Decision**

*No reliable method of estimating the revenue requirement for the 3 months of FY 1985 has been demonstrated. The difference between revenues collected under current and proposed rates will be minimal for the last 3 months of FY 1985. Therefore, BPA does not include the costs and revenues for these 3 months in the scaling process.*

### 3. Seasonal Differentiation

**Issue**

*How should the rate design adjustments be seasonally differentiated?*

**Summary of Positions**

In BPA's initial and supplemental proposals some of the rate design adjustments were seasonally differentiated in proportion to the billing determinants for the loads to which the adjustments were allocated. Other adjustments were seasonalized using the same percentages used in the COSA. Peters, BPA, TR 4247-4248. During cross-examination BPA agreed that it is appropriate to seasonalize all rate design adjustments using the COSA percentages. Metcalf, BPA, TR 4250. PGP proposes that rate design adjustments be seasonally differentiated on the basis of allocation factors instead of billing determinants. Knitter, PGP, E-PG-11, 2. NIU proposes crediting the nonfirm revenues to the seasons in which they are earned. Hittle, NIU, E-NI-01, 8; Initial Brief, NIU, B-NI-WS-NE-01, 10. NIU also proposes assigning the capacity-related rate design adjustments to seasons on the basis of loss of load probability (LOLP). Hittle, NIU, E-NI-025, 5. LOLP is the basis on which the capacity costs are seasonalized in the COSA. NIU acknowledges that it is reasonable and appropriate to seasonalize all rate [page 194] design adjustments, except equalization of demand, in accordance with the COSA percentages. Initial Brief, NIU, B-NI-WS-NE-01, 10-12.

**Evaluation of Positions**

The use of billing determinants to seasonally differentiate the rate design adjustments provides a variety of results for dividing costs between winter and summer seasons. BPA, E-BPA-08, Table 6; Peters, BPA, E-BPA-33S, Attachment 3. The PGP's proposed use of allocation factors instead of billing determinants also would provide a variety of cost divisions between seasons. Applying the COSA seasonal differentiation percentages to the rate design adjustments maintains the seasonal relationships found to be appropriate in the Marginal Cost Analysis and Cost of Service Analysis. Additionally, uniform seasonal differentiation helps simplify a complex process. However, seasonal differentiation percentages are not applicable to the equalization of demand adjustment because it is computed separately for each season. BPA, E-BPA-08, Table 18.

It is not appropriate to credit nonfirm energy revenues to the seasons in which they are earned. To do so would assign most of the benefits from the nonfirm sales to the summer season, while most of the costs are apportioned to the winter season. The costs of producing firm power and nonfirm energy are Joint costs. Metcalf, BPA, E-BPA-64R, 8. Over two-thirds of the Joint generating costs are assigned to the winter seasons. BPA, E-BPA-01, Table 7; BPA, FS-BPA-01, Table 7. Crediting nonfirm revenues to the season when earned would credit over 90 percent of these revenues to the summer season. Hittle, NIU, E-NI-02, 9; BPA, FS-BPA-08, Table 10. This would be illogical. In addition, the ability to make a large amount of summer power and nonfirm energy sales stems in part from foregoing sales in the winter. During the winter, water (energy) is stored to assure meeting loads in future periods and to provide the water budget for fish flow enhancement in the summer season.

**Decision**

*The uniform seasonal differentiation percentages used in the COSA are applied to all rate design adjustments except equalization of demand. This maintains the appropriate seasonal cost relationships and it helps simplify a complex process. Crediting of nonfirm energy revenues to the seasons when they are earned fails to recognize system operation that uses the flexibility of the Federal hydro electric system to make nonfirm energy available when it is marketable, or needed for fish flow enhancements. Moreover, the crediting of nonfirm revenues to the seasons when such revenues are earned would produce widely divergent seasonal rates. Such rates would not reflect relative costs incurred in the seasons as indicated in the Marginal Cost Analysis.*

### 4. Sequencing

**Issue #1**

*When should the adjustments for the section 7(b)(2) cost and credit occur in the rate design sequence?*

[page 195]

**Evaluation and Decision**

The sequencing of the adjustment for the 7(b)(2) cost and credit was raised as an issue by several parties in this rate proceeding. The draft decision in the Evaluation of the Record stated that the issue is moot because the preference customer rate test does not trigger. BPA, Evaluation, A-01, 258. APAC replied that the issue must be resolved because "one purpose of this watershed rate proceeding is to apply certain statutory directives for the first time." Reply Brief, APAC, R-PA-01, 18. A decision on this issue has no practical application in this rate proceeding since the preference customer rate test does not trigger. Furthermore, a decision on sequencing the 7(b)(2) cost and credit in this rate proceeding made on a theoretical basis would not necessarily be binding for future rate proceedings. Therefore, no decision on the sequencing of the 7(b)(2) cost adjustments has been made.

**Issue #2**

*Should the DSI markup rate be calculated before or after the Priority Firm Power rate is adjusted for equalization of demand?*

**Summary of Positions**

BPA originally calculated the DSI markup rate before the demand charges for the Priority Firm and Firm Capacity rates were equalized. The DSI markup rate was calculated before the equalization of demand charges because equalization of demand depends on the final allocated costs to the PF customers. Peters, BPA, E-BPA-33, 3-7; BPA, E-BPA-08, 12. The DSIs argue that the DSI markup rate should be calculated after the equalization of demand. They state that the equalization of demand charges results in a reduction in the PF rate; therefore, calculating the DSI markup rate before equalization of demand results in a DSI rate that exceeds the retail rate charged industrial customers of the region's preference customers. Schoenbeck, DSI, E-DS-02, 21-22; Initial Brief, DSI, B-DS-01, 20-22.

**Evaluation of Positions and Decision**

For the initial proposal, BPA calculated the DSI markup rate using a preliminary PF rate before equalization of demand charges in order to simplify the rate calculations. In cross-examination, BPA indicated that applying the 7(c)(2) margin to the PF rate after equalization of demand would make the rate calculation more complex but would not be impossible. Peters, BPA, TR 4138. BPA has discovered that the modeling difficulties are not as great as originally anticipated. Therefore, the Rate Analysis Model has been modified so that the DSI markup rate is calculated after equalization of demand and after the PF rate is reclassified using MCA percentages based on a load management program.

[page 196]

### 5. DSI First Quartile

**Issue #1**

*What generation cost should be assigned to DSI first quartile service?*

**Summary of Positions**

BPA does not plan or acquire resources to serve the DSI first quartile, so generation costs are not allocated in the COSA to the first quartile service. Instead, an opportunity cost is assigned for the first quartile and included in the rate design adjustment for excess revenues. In the initial proposal, BPA computed the total opportunity cost by multiplying the annual average nonfirm energy rate, less the transmission component, by the amount of expected first quartile service. BPA, E-BPA-08, 31, 123; Peters, BPA, E-BPA-33, 10-11. PPC argues that the value of the nonfirm energy to non-DSI customers varies during the year, while service to the DSIs is fairly even through the year even during months when nonfirm energy is valuable because it is scarce. PPC also proposes to recognize a higher quality of first quartile service by using the monthly average nonfirm energy rate plus the guarantee surcharge to measure the opportunity cost. In months when no nonfirm energy is available to non-DSI customers, PPC proposes using the NF-85 standard rate plus the guarantee surcharge. O'Meara, PPC, E-PP-03, 15-16. The DSIs argue that the opportunity cost is actually lower than that estimated by BPA because the average nonfirm rate would be less if the energy were offered in the nonfirm energy market. Carter, DSI, E-DS-03, 15; Reply Brief, DSI, R-DS-01, 28.

**Evaluation of Positions and Decision**

The generation portion of the annual average nonfirm energy rate is used to measure the opportunity cost of serving the first quartile. This methodology is fair and equitable for first quartile service with nonfirm energy, provisional drafts, and surplus firm power sold in the nonfirm markets. It approximates the revenue BPA could receive in other markets. The Positions and arguments are the same as those discussed in the 1983 rate proceeding. *See* 1983 Rates ROD, 254-6.

**6. Excess Revenues Adjustment**

**Issue #1**

*How should the excess revenues be allocated in light of the new NF-85 rate proposal?*

**Summary of Positions**

In the initial and supplemental proposals BPA included only Federal generation and transmission costs in the nonfirm energy rate. Exchange
[page 197] resource costs were not included. BPA divided the excess revenues between FBS and new resources and between segments of the Federal transmission system. BPA, E-BPA-08, Tables 8 and 9; Peters, BPA, E-BPA-33S, 8. BPA revised its proposed NF-85 rate to include exchange resource costs. Metcalf, BPA, E-BPA-64R, 23-25 and Attachment A10. *See* Section I. It is thus no longer appropriate to credit excess revenues against only the Federal generation and transmission costs. This issue was not raised in testimony but arises from BPA's new proposal.

**Evaluation of Positions and Decision**

The excess revenues are divided between generation and transmission based on the generation and transmission components of the target average revenue. The generation and transmission portions of the excess revenues are then divided between Federal and exchange resources by determining the increases in the generation and transmission components of the target average revenue due to the inclusion of exchange resource costs and loads. These increases, as percentages of the target average revenue components, represent the portions of the generation and transmission excess revenue credits allocated to loads served by the Exchange resource. The balances of the generation and transmission excess revenue credits are allocated to loads served by the Federal resources.

## B. Value of Reserves Analysis

BPA provides a credit to the DSIs to reflect the value of the system reserves that they provide. In the initial proposal BPA included a study assessing the value to BPA of the reserves provided by BPA's ability to restrict the DSIs' load. Issues related to the value of reserves analysis are discussed in this section.

**<u>Issue #1</u>**

*Has BPA correctly measured the forced outage reserves provided by the DSIs?*

**<u>Summary of Positions</u>**

BPA's capacity reserve requirement is based on the resources in operation during the test year. Reserves are calculated as 5 percent of hydroresources and 15 percent of thermal resources. The maximum Federal reserve requirement for FY 1987 is 1290 MW. In prior rate cases, BPA assumed the construction of combined cycle combustion turbines with a capacity of 1880 MW to provide reserves. The test year reserve requirement, 1290 MW, is less than the 1880 MW capacity of the combustion turbines. Therefore, the existing assumed facilities will cover the reserve requirement for FY 1987. BPA, E-BPA-08, 337. The value of forced outage reserves is the annual cost of the combustion turbines prorated based on the amount of reserves required in the test year to
[page 198] the amount of generation installed. BPA, E-BPA-08, 343. Hourly output from the System Analysis Model shows no expected forced outages over the next 7 years due, for the most part, to the forecasted surplus. BPA, E-BPA-08, 338.

The PPC argues that the uncertain nature of the DSIs' load in the Pacific Northwest is good reason to compensate the DSIs far the reserves they provide in accordance with short-term load-resource balances. O'Meara, PPC, E-PP-04R, 22. However, both PPC and OPUC argue that BPA overstates the amount of reserves provided by the DSIs in light of the low level of expected forced outages for the near term and the amount of BPA's unsold surplus. White, OPUC, E-OP-01, 8-9; O'Meara, PPC, E-PP-03, 2-3.

The DSIs argue that BPA understates the amount of reserves they provide. The DSIs argue that BPA has departed improperly from general ratemaking principles by determining the value of forced outage reserves from a Federal reserve requirement based on resources, rather than on forecast loads. Peseau, DSI, E-DS-05, Attachment 2, 4-5.

**<u>Evaluation of Positions</u>**

In making its case that BPA overstates the value of DSI forced outage reserves, PPC argues four points. First, no forced outages are expected over BPA's 7 year planning horizon. Second, BPA expects an unsold surplus in FY 1986 and FY 1987 that could be used to meet an unexpected decrease in resources. Third, most of the firm surplus that BPA does expect to market will be sold to the Pacific Southwest. Regional preference dictates that this power should be made available to the Pacific Northwest prior to the interruption of DSI loads. O'Meara, PPC, E-PP-03, 2-3. Fourth, a DSI may terminate its contract with BPA at any time and is not required to provide replacement reserves for the remaining life of the contract. O'Meara, PPC, E-PP-04R, 22. According to PPC, the result is that BPA currently pays large sums to the DSIs for reserves that BPA does not need, on the assumption that the DSIs will continue to provide such reserves at some uncertain date in the future, when BPA is no longer surplus. O'Meara, PPC, E-PP-03, 4.

The DSIs object to the PPC proposal that would treat the value of reserves as a function of the year-by-year probabilities that the reserves will be used. Forced outage capacity reserves are acquired to protect a utility against unexpected variations in peak load. By their very nature, capacity reserves have a low probability of use. Peseau, DSI, E-DS-15R, 1-2. The value of reserves is not derived from expected use for particular periods of time but from the reserves' usefulness in planning a sensible resource mix over the planning horizon. Peseau, DSI, E-DS-05, Attachment 2, 4. Finally, the DSIs assert that they and BPA both have recognized in past rate cases the long-term nature of DSI reserves. DSI capacity reserves are available throughout the 20-year lives of the DSI power contracts. Peseau, DSI, E-DS-15R, 2.

The DSIs also object that the PPC would use the unsold surplus for reserves. Such a proposal assumes that the surplus cannot be sold, whereas
[page 199] BPA would be prudent to attempt to sell all of it. Peseau, DSI, E-DSI-15R, 3. In addition, BPA has no assurance that surplus capacity will exist in sufficient amounts to support forced outages during the peak periods when they are most likely to occur. Peseau, DSI, E-DS-15R, 3; O'Meara, PPC, TR 4790-4791. BPA's current forecast of unsold firm surplus is considerably reduced from BPA's initial proposal.

Regarding the PPC proposal to use the 60 day pull-back provision under the Pacific Southwest contracts to provide reserves, the DSIs argue that such contracts require BPA to provide notice prior to terminating firm power deliveries. Since forced outages are emergencies that usually occur during the peak period, the 60-day pull-back provision is not useful in forced outage situations. The DSI contracts, on the other hand, require no advance notice of delivery restrictions. Peseau, DSI, E-DS-15R, 4. The PPC's counterargument is that the loss of a major resource can be met through drafting hydro resources below rule curves, so long as the power is replaced later. The 60-day call provision can provide such reserves. Initial Brief, PPC, B-PP-01, 37. The DSIs correctly point out that PPC has confused forced outage capacity restrictions with energy restrictions. Peseau, DSI, E-DS-15R, 4.

The DSIs also attack BPA's adoption of the Federal reserve requirement as a basis to determine the amount of reserves provided. The DSIs maintain that reserves, as any other resource, are planned to meet expected loads. They assert that BPA improperly departs from this reserve criterion by determining a Federal reserve requirement as a function of resources. Peseau, DSI, E-DS-05, Attachment 2, 4-5. This results in a lower amount of reserves provided than BPA would have obtained had it used the forecast level of DSI second and third quartile peak load, the method BPA allegedly used in prior rate cases to determine reserves. Peseau, DSI, E-DS-05, 12-14. The DSIs assert that BPA's case is internally inconsistent, since BPA maintains that the value of reserves does not depend on their probability of use, while adding that reserves in excess of the Federal reserve requirement are essentially without value. Initial Brief, DSI, B-DS-01, 52. The DSIs recommend that the actual level of second and third quartile load be used to determine forced outage reserves, "if one accepts the principle that near-term surpluses do not diminish the overall value of such reserves." Peseau, DSI, E-DS-05, 15.

The Federal reserve requirement does not measure probability of use, but simply the amount of reserves required by the Federal system. The existence of the near-term surplus does not reduce the amount of reserves required on the Federal system, because the reserve requirement is based on resources. It would not be correct to lower the reserves provided by the DSIs because the short-term load resource situation would allow substituting reserves from another source. However, this does not imply that BPA should pay the DSIs for more reserves than the entire Federal system requires.

Nor has BPA changed its method from prior rate cases. The Federal reserve requirement of 5 percent of hydro and miscellaneous resources and 15 percent
[page 200] of thermal resources has been used by the PNUCC and in BPA rate cases for several years to estimate BPA's forced outage capacity reserves. PNUCC, Northwest Regional Forecast, Federal Table 2, September 1980 to March 1984. Peters, BPA, E-BPA-57R, 7-8.

The DSIs are also mistaken in their interpretation of BPA's 1983 Record of Decision. The DSIs mention that BPA's initial proposal in 1983 recommended that forced outage reserves be determined from the forecast of second and third quartile load. They suggest that the 1983 Record of Decision is generally supportive of this position and that the 1985 rate case deviates from this former position. Peseau, DSI, E-DS-05, 13-14; Reply Brief, DSI, R-DS-01, 44. However, BPA’s 1983 initial proposal used the second and third quartile load to estimate its level of reserves, because this load was less than the highest monthly level of the Federal reserve requirement. Metcalf, BPA, WP-83-E-BPA-32, 64-65. In fact, the final proposal for the 1983 rate case based the value of forced outage reserves on the Federal reserve requirement in the same way that BPA proposes for the current rate case. The reason was the same in 1983 as today: the ability to restrict the DSIs' second and third quartile is greater than the reserves required. BPA, WP-83-FS-BPA-07, A3, A9, A12. The 1983 Record of Decision clearly supports BPA's position:

> The level of reserves the DSIs could provide in June through restricting the second and third quartile is greater than the level of reserves BPA requires during' the test year. The DSIs should not receive value for reserves provided above the amount BPA requires. BPA, 1983 Rates ROD, 339.

BPA's 1985 proposal does not deviate from this decision. The federal reserve requirement determines the level of reserves in this rate case for the simple reason that it is less than the DSIs' load from the second and third quartiles. Peters, BPA, E-BPA-57R, 8.

The fact that the DSIs can provide more reserves than are needed does not lead to the conclusion that BPA will use this entire amount or that the DSIs should receive credit for more than what BPA projects to be required during the test year. Peters, BPA, E-BPA-57R, 8. When the restriction rights exceed the reserve requirement in the Federal system, those additional restriction rights essentially have no value. Metcalf, BPA, TR 4105. Furthermore, as the PPC correctly points out, much of the third quartile is at risk to repay power advanced to the first quartile. BPA is likely to request the return of advanced first quartile energy at the same time the third quartile is required for reserves. O'Meara, PPC, E-PP-04R, 22.

**Decision**

*BPA correctly quantifies the forced outage reserves. Arguments raised by the parties show little change from the 1983 rate case. It is not appropriate to reduce the value of reserves for the short-term surplus, because that would*
[page 201] *be inconsistent with the need to plan for reserves. On the other hand, BPA should not assign a value to reserves in excess of the reserves needed for all Federal resources (including surplus resources).*

**Issue #2**

*Is BPA's valuation of forced outage reserves based on the capital costs of a hypothetical combustion turbine built in 1982 appropriate?*

**Summary of Positions**

BPA assumes that Federal forced outage reserve requirements would be met by the installation of combined cycle combustion turbines in the absence of DSI restriction rights. To meet the Federal reserve requirement in 1982, BPA assumed that 1880 megawatts of capacity were installed at a cost based on the escalated construction costs for the Beaver combustion turbine. The annual investment cost was based on a 14 percent interest rate. A nominal carrying charge is used to yield a simulation of BPA's repayment obligations associated with a particular project. BPA, E-BPA-08, 341-342. The PPC argues that a combustion turbine is not the most cost-effective approach to meeting reserve requirements in the absence of DSI restriction rights. The ability of the DSIs to terminate their contracts renders their reserves less certain than a combustion turbine. O'Meara, PPC, E-PP-03, 5. In addition, the PPC argues that BPA's interest rate of 14 percent is too high. BPA should use its current interest rate of 11.67 percent. O'Meara, PPC, E-PP-03, 6-7. The DSIs argue that a 14 percent interest rate is appropriate. Schoenbeck, DSI, E-DS-15R, 6-7. The OPUC objects to the use of a hypothetical facility based on 1982 construction costs and 1982 interest rates to estimate the current value of DSI reserves. White, OPUC, E-OP-01, 8-9.

**Evaluation of Positions**

The PPC argues that BPA inappropriately assumes that the DSIs will provide reserves over a 20-year period and that if such reserves were absent BPA would need to purchase a combustion turbine to provide the needed capacity. O'Meara, PPC, E-PP-03, 3-5. The PPC believes that the ability of the DSIs to terminate their contracts, as the case of Stauffer Chemical Company illustrates, renders their reserves less certain than reserves from a combustion turbine. O'Meara, PPC, E-PP-03, 4-5. Therefore, BPA should compensate the DSIs for the reserves they provide in accordance with short-term load-resource balances (see Issue #1). The DSIs contend that the PPC confuses capacity and energy reserves. BPA's forced outage capacity reserve methodology is based on a long term fixed obligation that is assumed to have occurred in 1982. This is a fixed cost whose relation to load-resource balance in the long run is without relevance for forced outage capacity reserve calculations. Peseau, DSI, E-DS-15R, 4-5.

The annual interest rate used by BPA to finance the combustion turbine is too high, in PPC's opinion. BPA should use no more than 12.75 percent, which
[page 202] is the cost of capital that a public agency would have paid in calendar year 1982 for funds to construct generating facilities. O'Meara, PPC, E-PP-03, 6. BPA ought to use, however, the current interest rate of 11.67 percent. This would compensate for the overcharges incurred in recent years as a result of the difference between 14 percent and 12.75 percent interest rates, whose amount could be treated as a fund to cover refinancing costs. O'Meara, PPC, E-PP-03, 7. The PPC asserts that the cost of refinancing would be less than the amount designated by the fund to cover such refinancing. PPC, Reply Brief, R-PP-01, 19.

The DSIs state that 14 percent is an accurate estimate of a carrying charge through mid-1982, and that the 12.75 percent was an interest rate in effect well after the 1982 Record of Decision had been published. Peseau, DSI, E-DS-15R, 6. The DSIs are correct in their presumption that the interest rate in effect during fiscal year 1982 is more applicable than calendar year 1982 to the construction of the hypothetical combustion turbine. Initial Brief, DSI, B-DS-01, 121-122. The interest rate in effect during FY 1982 is 13.75 percent. Armstrong, BPA, STR 766-767, BPA, FS-BPA-03, A9. Moreover, the assumed refinancing of a $770 million bond issue would have a significant impact on BPA's overall cost of borrowing. An additional demand for funds by BPA would tend to increase the interest rate associated with such borrowing. Peters, BPA, E-BPA-57R, 6. In its initial proposal BPA admits that it could have assumed that the option to refinance the combustion turbine would be exercised. It did not do so because of the presumed difficulty of refinancing loans due to market conditions and uncertainty. BPA, E-BPA-08, 342-343.

**Decision**

*BPA's assumptions regarding the hypothetical combustion turbines are retained. The uncertainty of the DSIs' continued level of operation in the Pacific Northwest does not alter the fact that BPA's contractual arrangements with the DSIs are long term in nature and provide for restriction rights over a 20-year period. BPA's assumed purchase of a combustion turbine in 1982 at 1982 interest rates represents an action that BPA could have taken shortly after the passage of the Northwest Power Act, had the DSI restriction rights not been available.*

**Issue #3**

*Should the DSI first quartile be included in the value of reserves analysis?*

**Summary of Positions**

The first quartile of DSI load is not included in the value of reserves analysis because BPA does not plan resources to meet this load. Peters, BPA, E-BPA-33, 28. The DSIs disagree with

this position, stating that the DSI first quartile is interruptible at all times to protect firm load and is therefore the most valuable of the reserves provided by DSI restriction
[page 203] rights. Peseau, DSI, E-DS-05, 6. PPC supports BPA's position on this issue. They argue that, since the Federal reserve requirement is completely resource-based, treating the first quartile as a reserve would add nothing to the value of reserves. The proper place to handle the question of first quartile service is in the 7(c)(2) margin study. O'Meara, PPC, E-PP-04R, 23.

**Evaluation of Positions**

According to the DSIs, the purpose of the value of reserves analysis is to calculate the additional revenue requirement BPA would face if it did not enjoy a contractual right to restrict DSI loads. For this purpose, the DSIs do not distinguish between the first quartile and the other three quartiles. The DSIs state that without restriction rights to the DSI first quartile, BPA would be required to plan resources for this load, just as for any other firm load. Peseau, DSI, E-DS-05, 6-7.

In essence, the DSIs fail to distinguish between any reserves that may be provided by the first quartile from those provided by the lower three quartiles. It is BPA's position that reserves associated with the first quartile are not to be valued in the same manner as reserves provided by the other three quartiles. In summary, the major issues associated with this disagreement between BPA and the DSIs may be stated as follows. First, service to the first quartile is distinctly different from service to the other three quartiles. Second, the types of reserves associated with the first quartile are different from those associated with the other quartiles. Third, the DSIs ignore contractual provisions under which the DSIs agree that BPA will not plan resources to serve the first quartile as firm. Fourth, BPA correctly takes into account the interruptible nature of the first quartile through the 7(c)(2) character of service adjustment. Fifth, the DSIs make improper use of information from the DSI Options Study. Sixth, the DSIs incorrectly propose to use the Systems Analysis Model to estimate first quartile energy reserves. Each of these issues will be discussed in turn below.

1. Service to the first quartile has a character different from that to the other three quartiles of DSI load. BPA treats the first quartile as firm only for purposes of resource operation, not resource planning. This treatment derives from the power sales contract. BPA has the right to restrict all of the DSI load under certain conditions, yet BPA must plan firm resources to meet only the lower three quartiles of this load. Peters, BPA, E-BPA-57R, 10. Because the first quartile is essentially a nonfirm load, BPA cannot *plan* on the availability of the first quartile to provide reserves at any given time. The DSIs have the right under almost all circumstances to curtail that load without penalties. This same unilateral right to remove load does not exist for the lower three quartiles, which are subject to curtailment provisions in the power sales contract. Although the first quartile is interruptible, it is interruptible in the same way any other nonfirm energy load is interruptible, although BPA makes a greater effort to avoid restricting the first quartile. The nature of nonfirm energy service is that energy may be pulled back at any time for any reason. On BPA's system,
[page 204] nonfirm energy is generally available in most years. Because of the nature of DSI operations, the DSIs provide a fairly stable market for nonfirm energy. As a result of this relationship, the value to BPA of the interruptibility of the first quartile is more closely related to

the nonfirm energy market than to the acquisition of an alternative resource.  In other words, removal of the nonfirm load with accompanying restriction rights would not cause BPA to increase the resources planned for reserves.

2.  The types of reserves associated with the first quartile are different from those associated with the other quartiles.  The other three quartiles provide planning reserves.  Planning reserves are any *firm* DSI load having restriction rights to protect the system against delays in the construction of new facilities, unexpected poor performance or forced outages.  *Central Lincoln II*, 735 F.2d at 1127.  BPA, 1981 Rates Summary Rate Design Study, 61.  Planning reserves provide firm support for the probability that - the planned performance of existing or proposed firm resources will not be met.  The first quartile is not a planning reserve, because it is not a firm load and is therefore not necessarily served with a firm resource.  Peters, BPA, E-BPA-57R, 10-11.  The first quartile is an operating reserve, defined as any DSI load not already valued as a planning reserve that may be restricted to cover any type of operating problem.  BPA, 1981 Rates Summary Rate Design Study, 61.

The DSIs recognize the distinction between planning and operating reserves.  The DSIs quote the legislative history of the Northwest Power Act to demonstrate that the first quartile "is to be treated as a firm load for purposes of resource operation and will provide an operating reserve."  Reply Brief, DSI, R-DS-01, 33.  The DSIs also quote from the power sales contracts, the Northwest Power Act, *Central Lincoln I*, and the BPA Administrator, all sources which distinguish clearly between planning and operating reserves.  Initial Brief, DSI, B-DS-01, 36-39, 41-43.  Reply Brief, DSI, R-DSI-01, 32-34.  The DSIs recognize throughout their testimony that the first quartile is distinguished from the other three quartiles by the fact that it is an operating, not a planning, reserve.  Then, having made this distinction, the DSIs inexplicably ignore it, calling such a distinction "irrelevant."  Reply Brief, DSI, R-DS-01, 32, 36.  This distinction is clearly not irrelevant, as BPA's discussion herein attests.

3.  The DSIs ignore contractual provisions which state that BPA will not plan resources to serve the first quartile as firm.  They then argue that absent the contract, BPA would have an obligation to serve the first quartile as firm.  There is no evidence on the record or in the contract to demonstrate how BPA would serve the first quartile, if at all, in the absence of first quartile restriction rights.  Absent such evidence, BPA cannot conclude that the first quartile would receive firm service.  BPA is under no obligation to serve the first quartile as firm.  While it is appropriate to associate the lower three quartiles with alternative resources for the purpose of valuing reserves, the first quartile has no such association.  This is the distinct feature of first quartile interruptibility.  As the Supreme Court noted in *Central Lincoln I*, "Once committed by contract, the interruptibility of the
[page 205] power is determined by the terms of the contract."  *Central Lincoln I*, 104 S.Ct. 2472, 2482 (1984).  Absent some compelling evidence to the contrary, BPA must be guided by clear contract language that disassociates the first quartile from any resource acquisition.

4.  Section 7(c)(2) of the Northwest Power Act specifically recognizes that the determination of the industrial margin in BPA's DSI rate design process should consider "the comparative size *and character* of the loads served" and the "relative costs of electric capacity, energy, transmission, and related delivery facilities provided and *other service provided*."  The character

of the first quartile thus receives explicit consideration in BPA's rate design process, contrary to DSI arguments that the first quartile is no longer given recognition for its restriction rights under the post-1985 process.

In essence, the DSIs argue that under pre-1985 rate directives, the value of first quartile reserves was recognized by having lower-than-firm rates. The DSIs state that this implicit recognition will no longer apply under the post-1985 rates, because all four quartiles of DSI load must be charged a firm rate based on the priority firm rate. Peseau, DSI, E-DS-05, 7. Again, the DSIs are incorrect. The character of service adjustment to the margin explicitly recognizes the use of nonfirm energy to serve the first quartile. Absent such recognition, the margin and thus the DSI rate would be higher. In effect, the DSIs receive a product that BPA attempts to provide as firm while charging only a nonfirm energy price. As the PPC noted, "The Regional Act grants BPA the discretion to determine the value imputed to DSI reserves and the methodology necessary to make that determination. BPA has chosen to exercise that discretion by treating the nonfirm character of the first quartile through the character of service adjustment to the typical margin." Reply Brief, PPC, R-PP-01, 21.

The Ninth Circuit Court of Appeals recently observed that the DSI rates must "be adjusted to reflect the interruptible nature of the service" the DSIs receive. *Portland General Electric Co. v. Johnson*, No. 83-7546 (March 45, 1985), slip opinion at 4. The court cited section 7(c)(3) of the Northwest Power Act in support of this general proposition. It is equally true that section 7(c)(2) supports this same proposition. Thus, BPA's proposal recognizes the character of interruptible service to the first quartile in the calculation of the industrial margin. Peters, BPA, E-BPA-57R, 11.

Moreover, section 7(c)(3) of the Northwest Power Act requires only that the Administrator "adjust rates to take into account the value of power system reserves" made available by the DSIs; it does not establish a precise methodology by which to do so. In providing a character of service adjustment for first quartile interruption rights, the Administrator has complied with the provisions of section 7(c)(3). First, the Administrator has adjusted the DSI rates in response to the Administrator's ability to interrupt the first quartile. Second, the Administrator has considered the value of the first quartile interruption rights during a time of surplus to be the value to BPA of serving that load with nonfirm energy instead of firm power. Finally, the [page 206] Administrator has determined that the interruptibility of the first quartile is associated with the nonfirm energy market in which loads simply are not served when nonfirm energy is unavailable, rather than with a firm load for which firm resources are built.

5. The DSIs argue that the rights to restrict the first quartile are worth 4 mills/kwh and that the value will escalate rapidly in the future. Reply Brief, DSI, R-DS-01, 42. The DSIs cite BPA in the DSI Options Study as supporting the position that unlimited interruptibility (equivalent to the rights to restrict the first quartile) has a value to the region of between 5 and 10 mills. In this respect, the DSIs cite a study that is not on the rate case record. Moreover, that conclusion is not relevant because it concerns conversion of a firm load to an interruptible load. As discussed previously, there is no evidence that the first quartile was ever to be served with firm resources on a planning basis. The first quartile was a nonfirm load before the Northwest Power Act, and it continued to be so after the passage of the Act. The DSIs also fail to point out that the study

determined that "the value for [BPA's] other customers from the increased interruptibility comes primarily in the years after 2001." DSI Options Study, Draft Report - Part 1, 24. This timing feature is significant. During the period of resource surplus that BPA currently faces, it is unlikely that any operating reserves provided by the first quartile will ever be needed. Unlike the lower three quartiles, for which BPA assumed the construction of a combustion turbine in 1982, the first quartile has no such resource associated with it. There is no reason, given the surplus, that BPA hypothetically should construct a similar resource today in order to value the first quartile.

6. The DSIs also propose to use the System Analysis Model to estimate the amount of energy reserves provided by the first quartile. Peseau, DSI, E-DS-05, 1-12. The restrictions modeled for the first quartile in the System Analysis Model primarily are the result of BPA's inability to serve this load due to the lack of nonfirm energy and the inability to move water forward in time. Peters, BPA, E-BPA-57R, 12. These restrictions are not entirely for reserve purposes but are also due to the characteristics of service provided the first quartile. Peters, BPA, E-BPA-57R, 12. The DSI assertion that these characteristics are precisely what makes the first quartile an energy reserve fails to distinguish operating from planning reserves. Initial Brief, DSI, 6-DS-01, 49. As for the DSIs' evaluation of first quartile capacity reserves, the PPC correctly argues that BPA's proposal compensates the DSIs only for the amount of the Federal reserve requirement. Treating the first quartile as a reserve would add nothing to the value of reserves, because required reserves already are met out of the second and third quartiles. O'Meara, PPC, E-PP-04R, 23. The DSIs counter with the argument that the existence of the first quartile restriction rights allows the Federal reserve requirement to fall below the second and third quartile expected load. Peseau, DSI, E-DS-05, 10. However, as the PPC notes, this argument ignores the fact that the Federal reserve requirement is resource-based and does not reflect BPA's loads. O'Meara, PPC, E-PP-04R, 23-24.
[page 207]

**Decision**

*The types of resources associated with the first quartile are different from those associated with the other three quartiles. The DSI power sales contracts and the legislative history of the Northwest Power Act recognize a clear distinction between operating and planning reserves. The interruptibility of the DSI first quartile is recognized properly in the character of service adjustment of the 7(c)(2) margin study. No other adjustment to the value of reserves analysis is made for the first quartile.*

**Issue #4**

*Is BPA's calculation of poor performance and conservation reserves correct?*

**Summary of Positions**

BPA does not explicitly model DSI restriction rights for poor performance of existing facilities or delay of conservation resources. To approximate DSI interruption for poor performance, regional firm load curtailments are multiplied by the ratio of the output of Federal thermal resources to the output of regional thermal resources in each of the 7 years of the planning horizon. BPA, E-BPA-08, 340. The DSIs propose that expected DSI curtailments would be modeled more accurately by considering both thermal and hydro plants in the ratio of Federal to regional plants. Peseau, DSI, E-DS-05, 18.

**Evaluation of Positions**

BPA did not include hydro resource output in its calculation, because hydro energy output is determined more by water conditions than unit forced outage rates. BPA, E-BPA-08, 340. While the DSIs agree that this is largely the case, they add that hydro facilities also experience poor performance due to forced outages. In fact, regional planning models all provide for forced outages of hydro facilities. Peseau, DSI, E-DS-05, 18. The DSIs allege that BPA's method understates the percentage that should be multiplied by expected firm curtailments, because thermal plants comprise a smaller percentage of Federal generating resources than they do of regional resources. Peseau, DSI, E-DS-05, 17. Under cross-examination, BPA stated that it would consider using a weighted average of hydro and thermal resources, as proposed by the DSIs, in its final proposal. Peters, BPA, TR 4118.

The DSIs also suggest another approach entirely, which they have revived from their 1983 direct testimony. The DSIs would use the plant performance used in the System Analysis Model to derive the probability distribution of the annual level of a plant's reduced capability due to poor performance. The total energy outage would be determined by multiplying the length of the outage by the reduced capability. Peseau, DSI, E-DS-05, Attachment 2, 7-9. In the 1983 Record of Decision, BPA rejected this approach, stating that it vastly overestimates poor performance reserves and that, while SAM is capable of modeling these restrictions, poor plant performance has not been
[page 208] sufficiently defined in modeling terms within the region. BPA, 1983 Rates ROD, 342-343. These conclusions are still valid in 1985.

**Decision**

*As recommended in the Evaluation of the Record, a weighted average of hydro and thermal resources is used to measure poor performance reserves in recognition of the potential poor performance by both resource types.*

**Issue #5**

*In the value of reserves analysis, how long should WNP-1 and WNP-3 be assumed to be delayed?*

**Summary of Positions**

The "BPA Review of Washington Public Power Supply System Projects 1 and 3 (WNP-1 and 3) Construction Schedule and Financing Assumptions" (BPA review) recommends that no construction funds for these plants be included in the rates proposed in the current case. In order for construction funds to he removed from the 27-month rate period, it is necessary to delay the assumed date for restarting construction by 27 months for WNP-3. For consistency, a 27-month delay is also assumed for WNP-1. Thus, a 27-month delay in the entire construction schedule is applied in conducting BPA's value of reserves analysis. Peters, BPA, E-BPA-33S, 3-4.

The DSIs disagree that the BPA review recommends a 27-month delay. The DSIs maintain that a 24-month delay was recommended and that the 27-month delay used by BPA understates substantially the resource delay restrictions to which the DSIs would be subject. While the BPA review does support the removal of WNP construction funds from BPA's budget for the 27 months of the rate period, the SAM runs upon which the BPA review was based and which show restrictions of the DSI second quartile assume a 24-month delay. Peseau, DSI, E-DS-055, 9-10.

**Evaluation of Positions and Decision**

The difference of opinion between BPA and the DSIs on this issue revolves around the proper interpretation of the BPA review, which states: "BPA should not include funds for construction for WNP-1 and -3 in its fiscal years 1986 and 1987 budgets, or in its rate case, for the period extending from July 1, 1985 to September 30, 1987" (p. 11). Peters, DSI, TR 4113-4114. While BPA maintains that this language calls for a minimum 27-month delay, the DSIs argue that the BPA review recommends a 24-month delay, but that money for the resumed construction of the WNP plants should not be included in the 27-month period covered by the rate case. Peseau, DSI, E-DS-05S, 9-10. The DSIs see an anomaly in BPA's interpretation, whereby a 27-month delay should be recommended based on a study that examines the effects of a 24-month delay. BPA sees no such anomaly. Peters, BPA, TR 4114. The BPA review states that
[page 209] it does not attempt to be a definitive cost-effectiveness analysis but to determine the assumptions to use in BPA's final rate proposal (page 1). The BPA review also states that further study is necessary to determine whether an additional delay of 5 years would be appropriate (page 6).

A 27 month delay in the construction schedule for WNP-1 and WNP-3 is assumed for the value of reserves analysis.

**Issue #6**

*How much of the value of reserves should be credited to the DSIs for the right to restrict their load?*

**Summary of Positions**

BPA computes the value of reserves credit using a share-the-savings formula, by which one-half the total value of DSI reserves is credited against the costs assigned to the DSIs. BPA, E-BPA-08, 37. The DSIs maintain that this method violates section 7(c)(3) of the Northwest Power Act. Initial Brief, DSI, B-DS-01, 63.

**Evaluation of Positions and Decision**

The DSIs maintain that the Northwest Power Act requires BPA "to take into account the value of [DSI] power system reserves," meaning the full value, not one-half the value. The DSIs add that in prior rate cases, BPA has relied inappropriately on Appendix B to Senate Report 96-272, which used this share-the-savings approach. The DSIs suggest that Appendix B was written at a time when billing credits were also assumed to be computed on a share-the-savings basis. However, the Northwest Power Act was finally amended to provide for full payment of billing credits. According to the DSIs, when BPA acquires in-place generating resources, grants billing credits, or funds conservation, it pays the full cost of these least cost alternatives. Similarly, the DSIs should be credited with the full cost of the alternative resources they provide. Initial Brief, DSI, B-DS-01, 63-64. These arguments by the DSIs were advanced in the 1983 rate case and rejected by BPA in the 1983 Record of Decision. BPA, 1983 Rates ROD, 178-180. Also, the Ninth Circuit Court of Appeals in *Central Lincoln II* decided, "BPA's assessment of a portion of the cost of the reserves to the DSIs by lowering the value of their reserve credit is appropriate because the DSIs are firm power customers who benefit from the reserve." 735 F.2d 1101, 1127.

### C. Priority Firm Power Rate

**Issue #1**

*Should there continue to be an "availability charge"?*
[page 210]
**Summary of Positions**

BPA proposes a continuation of the "availability charge" in the PF-85 and NR-85 rate schedules. This charge is actually a method of calculating the energy billing factor for computed requirements customers. BPA, E-BPA-08, 16-17, 52-53, 147; E-BPA-08A, 3-10; Peters, E-BPA-35, 12-20, Attachment 3. The energy billing factor takes into account the projected revenues lost when computed requirements customers displace firm power purchases from BPA with their own or purchased nonfirm energy, and BPA is forced to sell the displaced firm power on the nonfirm energy market. The goal of the adjustment is to hold BPA harmless after the displacement occurs, taking into account both allocated costs and expected revenues.

PGP opposes the availability charge, arguing that PGP members (1) are "singled out and penalized"; (2) already subsidize exchange customers; (3) were encouraged to build and operate resources in one manner but are now penalized for following that encouragement; and (4) provide specific net benefits to BPA for which they are uncompensated. Opatrny and Spettel, PGP, E-PG-07, 1, 6-8.

Both the PGP and ICP argue that the availability charge in the proposed NR-85 rate schedule violates the Power Sales Contract. Pre-Hearing Brief, PGP, P-PG-01, 11-12; Lauckhart, ICP, E-IC-05, 4-6; Pre-Hearing Brief, ICP, P-IC-01, 18.

**Evaluation of Positions**

BPA's proposal to continue the availability charge is based on a continued analysis of the displacement by computed requirements customers of firm purchases from BPA with nonfirm energy produced on their own systems. Data from the power bills submitted by BPA, and not disputed by the customers concerned, show that some computed requirements customers regularly displace 100 percent of their monthly computed energy maximum loads. Peters, BPA, E-BPA-35, Attachment 3, page 5. The PF-83 availability charge recovered 52 percent of the costs associated with BPA's obligation to serve the computed energy maximum through June 1984. These utilities thus were able to save approximately $7.8 million during this period by displacing firm purchases from BPA. Peters, BPA, E-BPA-35, Attachment 3, page 7. While the availability charge has not solved the underlying problem of displacement by computed requirements customers, it has succeeded in meeting BPA's objective of sharing the risk of providing firm service to these customers. Reply Brief, PGP, R-PG-01, 21; Peters, BPA, E-BPA-35, 20.

PGP argues that they are singled out for such a "penalty." Opatrny and Spettel, PGP, E-PG-07, 1. This is not true. Many customers have billing factors different from measured demand or measured energy that lead to amounts billed above amounts actually taken. These include the demand ratchet for computed requirements customers, the curtailment charge for DSI customers, and the specification of contract demand or energy as the billing amount for transmission, firm capacity, and other customers. Peters, BPA, TR 3623-3624.
[page 211] In all these cases the amount billed can and does exceed the amount actually taken. The availability charge is not unique.

The argument regarding exchange subsidies is not relevant to the question of the availability charge. Exchange costs are part of BPA's overall revenue requirement, and thus appear in *all* rates, including those charged BPA's other PF customers. Thus, although it is the case that computed requirements customers pay rates based in part on the cost of exchange resources, the rates paid by all PF customers include the cost of some exchange resources. BPA, E-BPA-08, 168. Metered requirements customers that do not participate in the exchange also pay for some of those exchange resources. PGP members are not treated any differently in this regard.

PGP argues that section 16(b) of the Power Sales Contract encourages customers to place on BPA the "least monthly requirements for energy, and … for capacity." Data response PG-6, TR 3631. However, the purpose of section 16(b) is to address constraints agreed upon by utilities for *planning* firm resources. The agreements in section 16(b) refer to Assured Capability, which is a planning concept that relates to firm resources. Those firm resources are measured against the customer's firm load to determine the customer's computed peak and energy requirements on BPA. BPA in turn must plan to serve that amount of firm load. Section 16(b) does indeed encourage customers to place a minimum of planned requirements on BPA. The problem of displacement however, relates to the *operational* substitution of nonfirm energy for firm purchases from BPA. This is not a matter of minimizing planned purchases from BPA, but of minimizing actual purchases. The availability charge is entirely consistent with the requirements of section 16(b) in its attempt to minimize the discrepancies between the computed requirements placed on BPA and the actual measured amounts that are purchased. Both the availability charge and section 16(b) attempt to encourage customers to keep their planned requirements in line with their realistic capacity and energy needs.

PGP also has presented the 1976 "Notice of Insufficiency" as support for this position. Data request PG-6, TR 3621. The circumstances forecast in that Notice did not materialize, nor did that Notice lead to an actual reduction in BPA's obligation to be ready to serve firm loads. Further, the Notice of in sufficiency discussed BPA's obligation to serve firm load. Even if actions had been taken to increase a purchasing utility's firm resource capability, the problem of displacement could still occur, because displacement is the result of the availability of nonfirm energy.

PGP raised the question of benefits provided by PGP members to BPA. Five potential benefits were discussed in PGP direct testimony, and reviewed in BPA rebuttal testimony: load factor maintenance, cost reduction to the PF class, operation of own load control centers, provision of storage, and provision of holding interchange. Opatrny and Spettel, PGP, E-PG-07, 6-8; Peters, BPA, E-BPA-52R, 3-6. First, high load factor on a system such as BPA's is not necessarily a benefit. This is because the marginal cost of capacity on BPA's hydro-thermal system is relatively low. Peters, BPA, E-BPA-52R, 4. Further, [page 212] PGP members are not always high load factor customers. Their loads generally are not flat over the entire diurnal cycle. Also, to the extent that the PGP members' load factors do provide a benefit, that consideration is already recognized in the PF demand and energy charges that are based on costs allocated by projected loads. Second, cost reduction to the PF class does not provide benefits to BPA, but simply rearranges existing costs among customer classes. Peters, BPA, E-BPA-52R, 4-5. Third, benefits resulting from operation of the PGP's own load control centers cannot be quantified by the method proposed by the PGP. The Service and Exchange Agreement uses "average costs of operating, scheduling, dispatching, and controlling Federal System power" in lieu of "incremental increase in [such] Federal System Costs" (Data response PG-3, TR 3621). Peters, BPA, TR 3641-3642. However, the Service and Exchange Agreements were established under specific circumstances that do not clearly hold for larger systems. Finally, provision of storage and holding interchange is governed by the Coordination Agreement. Peters, BPA, E-BPA-52R, 4-5; Spettel, PGP, TR 4536-4537. The charges, obligations and rights established pursuant to that Agreement are not the subject of this proceeding. It would be inappropriate to adjust rates for power based on a perceived misallocation of benefits achieved pursuant to that Agreement. Further, actions taken by participants to the Coordination Agreement may or may not have led to effects unanticipated by those participants at the time the Agreement was negotiated, resulting in such effects being unprovided for in the Agreement. PGP has been able only to allege such unanticipated and uncompensated effects, and has not shown that any misallocation of benefits has in fact occurred.

**Decision**

*The availability charge continues to provide BPA reasonable protection against lost revenue. PGP-members have not demonstrated a convincing case that the costs and benefits of firm service provided by BPA are inadequately recognized in the rates. The charge is retained in PF-85 and NR-85. However, BPA understands the strength of opposition to this charge by the PGP and is willing to seek a contractually negotiated solution to the problem of displacement of firm purchases by generating utilities.*

**Issue #2**

*How should computed requirements customers' displacement of firm purchases from BPA be calculated in the NFRAP?*

**Summary of Positions**

In BPA's supplemental testimony the NFRAP calculated the computed requirements customers' displacement of firm purchases (scheduled firm adjustment) by assuming that during winter energy charge or winter capacity charge months, the computed requirements customers would displace firm purchases from BPA with their own nonfirm energy rather than sell it at BPA's Standard nonfirm energy rate. Roghair, BPA, E-BPA-16S, A2, 8. The NFRAP [page 213] calculation of the scheduled firm adjustment is unaffected by estimates of how much extraregional (Canadian) energy will serve Pacific Northwest and Pacific Southwest nonfirm energy markets. Roghair, BPA, E-BPA-60R, 3.

PGP asserts that the computed requirements customers would purchase BPA energy up to their full entitlement, and would use their own nonfirm energy to make nonfirm energy sales. Spettel, PGP, E-PG-07S, 2. In addition, PGP argues that the NFRAP calculates the scheduled firm adjustment by improperly incorporating extraregional energy into the calculation. Spettel, PGP, E-PG-07S, 2-5.

**Evaluation of Positions**

PGP is correct in stating that computed requirements customers would use their nonfirm energy to make sales at BPA's proposed NF-85 Standard rate rather than use the energy to displace firm purchases from BPA. This is particularly true at the Standard nonfirm energy rate calculated by the method proposed in BPA's rebuttal testimony (Exhibit BPA-64R). since that rate is higher than the Standard rate proposed in supplemental testimony. BPA agreed during cross examination that the PGP proposal is correct. Roghair, BPA, STR 343-344.

PGP misunderstands how the NFRAP calculates the scheduled firm adjustment. The NFRAP calculation of the scheduled firm adjustment is unaffected by estimates of how much extraregional energy will serve nonfirm energy markets. Roghair, BPA, E-BPA-60R, 3; STR 341-343.

**Decision**

*The NFRAP used in BPA's supplemental testimony incorrectly assumed that computed requirements customers would use nonfirm energy to displace firm purchases from BPA rather than sell it as nonfirm energy during winter months. It is correct for the NFRAP to model the use of computed requirements customers' nonfirm energy to be sold at BPA's Standard nonfirm energy rate prior to being used to displace firm purchases from BPA.*

*The NFRAP correctly calculates displacement of firm purchases based only on PNW nonfirm resources, excluding Canadian resources.*

**Issue #3**

*Should BPA adopt a special rate for mining operations using indigenous raw materials?*

**Summary of Positions**

Cyprus Thompson Creek Mining Company (CTCM) submitted testimony requesting a provision in the PF rate schedule that would grant a rate reduction to those [page 214] utilities serving a mining operation load under certain conditions. Martin, CTCM, E-TC-01, 5; Initial Brief, CTCM/SREC, B-TC/IU-01, 2; Reply Brief, CTCM/SREC, R-TC/IU-01, 2. The Salmon River Electric Cooperative (SREC) supports the CTCM proposal to include a special incentive rate within the PF rate schedule for industrial loads engaged in the mining of minerals indigenous to the region. Hurless, SREC, E-IU-01R, 6; Initial Brief, CTCM/SERC, B-TC/IU-01, 1.

**Evaluation of Positions and Decision**

CTMC proposes a special reduced rate for mining operations under the PF rate schedule. Martin, CTCM, E-TC-01, 1. Mining operations circumstances are unique in that "the process of extracting ore from the ground is itself energy intensive and place bound." Initial Brief, CTCM/SREC, B-TC/IU-01, 2. In other words, a mining operation must exist in areas where the ore is found. Martin, CTCM, E-TC-01, 5. Such a rate would be offered only if the economic and power supply conditions make those sales in the best interest of BPA and all its customers. Initial Brief, CTCM/SREC, B-TC/IU-01, 2. The rate offer is contingent on the following conditions:

(a) The utility serves an ultimate customer which is a mining operation using indigenous raw materials;
(b) The ultimate customer establishes to the satisfaction of BPA that total BPA revenues will be higher if the reduced rate is offered, because of enhanced or continued operation of the mining facility; and
(c) The serving utility agrees to purchase power from BPA at such reduced rate and to pass the benefits there of through to the mining operation. Martin, CTCM, E-TC-01, 5; Initial Brief, CTCM/SREC, B-TC/IU-01, 2.

SREC's support of the rate reduction proposed by CTCM is contingent on the rate relief being provided under the PF rate schedule and not through CTCM attaining DSI status through the transfer of an existing DSI power sales contract. Hurless, SREC, E-IU-01R, 7.

CTCM asserts that continuation of the mining operation is in the region's best interest. BPA and all its customers will benefit because operation of the mine will result in revenues for BPA. SREC customers will similarly benefit given that CTCM is its single largest customer. And those who depend directly on the mining production will benefit. Martin, CTCM, E-TC-01, 4. Currently, CTCM is the largest single employer in the area. The mining operation has also had secondary employment impacts. Martin, CTCM, E-TC-01, 4; Hurless, SREC, E-IU-01R, 4; Initial Brief, CTCM/SREC, 6-TC/IU, 1. Finally, given the current power surplus, it is in the best interests of BPA and its customers to "preserve" all possible markets and to attempt to market as much of this power as possible. Martin, CTCM, E-TC-01, 4; Initial Brief, CTCM/SREC, B-TC/IU-01, 4.

[page 215]

BPA agrees that the circumstances facing mining industries are unique in that they are tied to a particular geographic location. BPA also agrees that a short run temporary rate reduction could result in retention on a long term basis of a mining load that could contribute to the overall economic health of the region, thereby benefiting BPA and all its customers. However, BPA recognizes and is concerned about other retail industrial loads in the region that are experiencing financial difficulty. In sufficient evidence has been presented that would support limiting such a discount to mining loads, nor has the potential scope of a more widely available discount been adequately examined in this proceeding. BPA is considering conducting a separate 7(i) process in which the issues associated with developing and implementing incentive rates for retail industrial customers in the region would be addressed.

**Issue #4**

*What is the appropriate relationship between capacity and energy rates for the PF class?*

**Summary of Positions**

BPA's initial proposal determined the relationship between capacity and energy rates in the PF class by classifying generation costs in the COSA and revenue adjustments in the WPRDS uniformly in accordance with the results of the MCA. Emery, BPA, E-BPA-23, 2.

WPAG argues that BPA has priced itself out of the capacity market. Hutchison, et al., WPAG, E-WA-01, 46. WPAG indicates that BPA's utility customers face a highly competitive situation with regard to alternative power sources. Hutchison, et al., WPAG, E-WA-01, 31-32; Pre-Hearing Brief, WPAG, P-WA-01, 11; Initial Brief, WPAG, B-WA-01, 19-20. WPAG argues that load management in the form of a one-way radio control water heater program can provide capacity at a cost less than purchasing from BPA. Pre-Hearing Brief, WPAG, P-WA-01, 13-14; Hutchison, et al., WPAG, E-WA-01, 37-38, 46; Initial Brief, WPAG, B-WA-01, 21-22; Hutchison, et al., WPAG, E-WA-02R, 20; Reply Brief, WPAG, R-WA-01, 24-31.

The Evaluation of the Record proposes that the costs allocated to the PF rate class be reclassified based on the MCA percentages calculated using load management as the least-cost marginal capacity resource. BPA, Evaluation, A-01, 280-281.

WPAG supports the reclassification of PF costs. Reply Brief, WPAG, R-WA-01, 30-32.

PGP criticizes the reclassification of PF costs by asserting that it is unsupported by theory or practicality, and claims that the procedure will exacerbate BPA's marketing problems. Reply Brief, PGP, R-PG-01, 13-15.

[page 216]

APAC agrees with PGP that the reclassification of PF costs is unsupported by theory or by the record, and criticizes the PF cost reclassification as "result driven" rather than based on cost causation as APAC prefers. Reply Brief, APAC, R-PA-01, 29-30.

APAC/PGP/DSI also asserts that the reclassification of PF rate costs is unsupported and has no purpose, and that the use of classification percentages based on the cost of load management will send price signals that encourage operational inefficiency. Reply Brief, APAC/PGP/DSI, R-PA/PG/DS-01, 1-5.

**Evaluation of Positions**

The primary objective in classifying costs between capacity and energy is to create the most economically efficient relationship between BPA's costs and rates. Emery, BPA, E-BPA-23, 1. Classification of costs as a step in ratemaking sends signals to BPA's customers regarding BPA's relative costs of energy and capacity, thus encouraging more economically efficient consumption and investment decisions. Emery, BPA, E-BPA-23, 3; Hutchison, et al., WPAG, E-WA-01, 31. WPAG states that customer utilities can purchase capacity through load management at a lower cost than from BPA. Hutchison, et al., WPAG, E-WA-01, 46. WPAG recommends that the overall classification percentages should be based on the cost of load management. Hutchison, et al., WPAG, E-WA-01, 37-38; Reply Brief, WPAG, R-WA-01, 24-25. This use of the residential load management program was determined to be inappropriate for BPA's overall classification. See Chapter IV, Section D, Issue 1. However, the basic WPAG position is clearly documented and readily understood. Given BPA's price signals and the cost of load management, utility customers could save money by undertaking residential load management programs and curtailing purchases of capacity from BPA. This is clearly an inappropriate result given the current surplus in capacity. Fuqua, BPA, E-BPA-14, Attachment 7.

Several parties contend that the proposed reclassification of PF costs is unsupported by the record. Reply Brief, PGP, R-PG-01, 14; Reply Brief, APAC, R-PA-01, 31; Reply Brief, APAC/PGP/DSI, R-PA/PG/DS-01, 2. Their contention is untrue. WPAG thoroughly documented its calculation of marginal capacity costs using a load management program. Hutchison, Muller, Saleba, and Schneider, WPAG, E-WA-01, 36-39 and Attachments 5, 6, 7, and 9; E-WA-02R, Attachments 5R, 6R, 7R, and 9R. WPAG's claim that load management is a cost effective substitute for utilities' capacity purchases from BPA is clearly supported by their cost calculations. Support for reclassifying the costs allocated to the PF rate in order to address WPAG's concerns appears in the MCA and related testimony: prices based on marginal cost principles, including classification percentages based on results of the MCA, provide price signals that encourage economic efficiency. BPA, E-BPA-02, 3; Emery, BPA, E-BPA-23, 3.

Besides providing theoretically correct price signals to BPA's customers, the reclassification of PF costs serves the purpose of addressing marketing considerations. BPA's current surplus of firm power has caused BPA to implement various rate design features to enhance the marketability of the surplus. BPA, E-BPA-08, 20-26; *see also* BPA, FS-08. BPA's reclassification
[page 217] of PF costs enhances this effort. PGP asserts that reclassifying the PF costs will exacerbate the problem of utilities purchasing capacity from sources other than BPA. Reply Brief, PGP, R-PG-01, 15. PGP's assertion is unsupported by evidence and the reasoning behind it is not clear.

The parties' argument that BPA is encouraging "lower load factor, and less efficient energy consumption," is not correct. Reply Brief, APAC, R-PA-01, 32; Reply Brief, APAC/PGP/DSI, R-PA/PG/DS-01, 4-5. First, BPA is not encouraging lower load factors. The PF reclassification is designed to avoid encouraging customers to build capacity resources at a time when the region is facing a capacity surplus, resources that would raise their BPA load factors. Second, the argument alleging a connection between load factor and efficiency has been made separately and has been soundly rejected. See Issue #1 above regarding the availability charge and Issue #2 in Chapter II, Section E.1. regarding rate design and system load factor. Given the capacity surplus, it would *clearly* be in efficient to encourage the construction of additional capacity resources. The parties' argument in this regard is illogical.

The parties argue that the classification percentages based on load management should not be applied to the PF rate class as a whole, since the WPAG load management example is targeted to residential water heaters and the PF rate class is made up also of commercial and industrial loads. Reply Brief, APAC, R-PA-01, 31; Reply Brief, APAC/PGP/DSI, R-PA/PG/DS-01, 3-4. The parties are correct that the load management program whose costs are used in the MCA is targeted to only residential loads. The peak megawatts saved by such a program, however, would serve as a system resource for the utility. The utility as a whole would save on its monthly BPA power bill at the capacity rate effective for the utility. Since it is the utility that faces BPA's capacity rates, and the utility that would benefit from load management, it is reasonable to apply the reclassification percentages based on load management across the entire PF rate class. In addition, load management is the marginal capacity resource for the utilities that purchase power at the PF rate. The customer class associated with the resource is irrelevant. BPA's rates, which incorporate marginal cost principles, logically recognize the substitution of load management at the margin.

**<u>Decision</u>**

*As a final step in the rate design process BPA reclassifies the costs allocated to the PF rate according to the classification percentages based on the recommended load management program. Use of the MCA classification percentages calculated using a combustion turbine for cost allocation and the design of rates other than PF is appropriate because those rate classes do not have a load management alternative. Design of the PF rate using the MCA classification based on combustion turbine costs could provide PF customers with an incentive to purchase additional non-BPA capacity resources during a time of capacity surplus. This is clearly not in the region's interest. An adjustment to PF classification is thus consistent with BPA's ratemaking criteria and considers both BPA's cost and the alternatives clearly and readily available to BPA's utility customers, who must consider all alternatives available in the wholesale power market.*

[page 218]

## D. Industrial Firm Power Rate

The Industrial Firm Power (IP-85) rate applies to Federal power purchases by BPA's DSI customers. Three rate options are maintained in this rate schedule for purchases of Industrial Firm Power: the Standard rate, the Premium rate, and the incentive rate. The IP-85 Standard rate is available for first quartile service with nonfirm energy and provisional drafts. The Premium rate is for service to the first quartile with surplus FELCC. BPA has also continued an incentive rate that may be executed, contingent on a determination that BPA's total revenues will increase if such a lower rate is contractually offered and accepted on a take-or-pay basis.

In the initial proposal, each of the IP-85 rate options included a customer charge component as well as demand and energy charges. BPA later eliminated the customer charge component from its proposal because of further research on the long run effects of the customer charge and updated assessments of the aluminum market. The IP-85 rate also includes a credit for the value of the reserves provided by BPA's rights to restrict the DSI load.

**Issue #1**

*Should the IP-85 rate schedule include a customer charge?*

**Summary of Positions**

Initially BPA proposed to retain a customer charge component in the IP-85 rate. The intent of the customer charge was to enhance BPA's revenue stability from this customer class, and to promote the short-run stability and efficiency of DSI operations by lowering the variable costs of electricity. Melton, BPA, E-BPA-36, 3, 5. In supplemental testimony, BPA modified its initial position and proposed eliminating the customer charge, because continuation of the customer charge was found to be counterproductive. That is, the customer charge could increase the risk of plant termination and reduce BPA's revenues. This conclusion is based on (1) additional research and analysis on the expected long-run impact of the customer charge on DSI loads; (2) revisions to BPA's assessment of current and expected conditions in aluminum markets generally; and (3) specific developments in the regional aluminum industry. Melton, BPA, E-BPA-36S, 1-4; Hoffard and Moorman, BPA, E-BPA-10S, 2-8.

NWU argues that removing the customer charge destroys a "balanced approach" to reducing DSI revenue fluctuations. The customer charge coupled with an incentive rate works to encourage DSI operation. O'Meara, NWU, E-NU-05, 2-3, 14. NWU is concerned that BPA's "preoccupation" with maintaining marginal Northwest aluminum smelters may potentially jeopardize BPA's financial position and shift some costs from the DSIs to BPA's other customer groups. O'Meara, NWU, E-NU-04, 2; O'Meara, NWU, E-NU-05, 15-1 6; Initial Brief, NWU, B-NU-01, 2. After reviewing BPA's analyses of the impacts
[page 219] of the customer charge, NWU argues that the analyses are incorrect and do not support eliminating the customer charge. Wolverton, et al., NWU, E-NU-10, 7-16; Initial Brief, NWU, B-NU-01, 74; Reply Brief, NWU, R-NU-01, 22-25. NWU also disagrees with BPA's interpretation of the underlying economic theories that led to changes in the DSI rate design. Wolverton, et al., NWU, E-NU-10, 16-29.

OPUC also supports retaining a customer charge component in the DSI rate. They agree with NWU that elimination of the DSI customer charge might subject BPA to greater revenue instability. White, OPUC, E-OP-01, 7. BPA should not concede to ad hoc DSI rate concessions that would be unfair to other BPA customers and that might be unnecessary to keep the DSIs operating at a high level. White, OPUC, E-OP-01, 10. OPUC/WUTC argues that because BPA's data and analysis are not adequately explained, BPA should retract its decision to eliminate the customer charge until further study and more complete public discussion have taken place. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 2, 8-1 1. WPAG also contends that BPA's analysis is incorrect, and that the customer charge should be retained in the IP-85 rate to assure a certain amount of revenue regardless of the level of DSI operations. Hutchinson, et al., WPAG, E-WA-01S, 10-11; Reply Brief, WPAG, R-WA-01, 7-9.

**Evaluation of Positions**

Two subsections are identified below, addressing separate questions. A general decision appropriate to the evaluation of both subsections follows.

***BPA's Analyses of the Impact of the Customer Charge***

In considering the impact of the customer charge. BPA conducted three analyses. In the *first*, the loads of regional aluminum smelters with and without the customer charge under different aluminum price scenarios were forecasted using BPA's plant-specific Aluminum Smelter Model (ASM). This analysis indicates that the customer charge tends to hold DSI loads higher only under moderate aluminum price reductions in the short run. Melton, BPA, E-BPA-365, 2. During severe price reductions, the DSI loads decline even with a customer charge. Melton, BPA, E-BPA-36, 21. OPUC/WUTC argues that this analysis did not support eliminating the customer charge. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 8. WPAG echoes this concern and argues that the analysis instead supports retaining the customer charge. Hutchinson, et al., WPAG, E-WA-01S, 9-10.

BPA's analysis of loads with and without the customer charge was intended to identify the incremental loads and revenues that would potentially be lost in the short run if the customer charge were eliminated, against which the impact of potential plant closures could be compared. The first analysis must be considered in conjunction with other BPA analyses that indicate that the probability of such plant closures is increased as a result of the customer charge.

BPA addressed the question of whether the customer charge increased the probability of plant closures in a second analysis of regional aluminum [page 220] smelters with and without the customer charge under different aluminum price scenarios, using a simple discounted cash flow model. The net cash flows of the regional smelters over a 5-year period would be worse with the customer charge if aluminum prices are depressed or fluctuating. For plants being considered for closure or sale, the customer charge would make closure more likely and would reduce the probability of a successful sale. Melton, BPA, E-BPA-36S, 2. NWU disagrees with this conclusion:" Martin Marietta closed despite an announcement that the customer charge might be eliminated. While the 1983 rates have been in effect, Comalco offered to purchase the Goldendale smelter." Initial Brief, NWU, B-NU-01, 75. NWU further asserts that it is not reasonable to conclude that BPA's rate level or design caused Martin Marietta to close. Initial Brief, NWU, B-NU-01, 60.

NWU asserts that BPA's second analysis of the customer charge is based on "incorrect assumptions concerning the economics of the aluminum industry." Wolverton, et al., NWU, E-NU-10, 1. NWU argues that cash flow is not a useful criterion in determining whether a smelter would shut down, because future decisions to operate a smelter will be based on the marginal costs of future operation and not on the amount of capital already sunk into the plant. Wolverton, et al., NWU, E-NU-10, 8-10. NWU has misinterpreted BPA's analysis. BPA did not consider "sunk costs" associated with initial plant investment. In addition, cash flow is a valid criterion regarding operation of existing plants because it is a measure of plant profitability. A plant with a negative cash flow is a candidate for divestiture or closure by a firm striving to maximize long-run profits. Hoffard and Moorman, BPA, E-BPA-51R, 2-3.

NWU also asserts that the second analysis was more pessimistic than BPA's own current assumptions because it did not consider BPA’s high aluminum price scenario. Wolverton, et al., NWU, E-NU-10, 11. The analysis by design did not address a high aluminum price scenario, because the base case already showed positive discounted net cash flows. A high price scenario would only yield higher cash flows. BPA was most interested in determining whether the regional plants are viable at lower prices, not higher prices, since indications suggest the base case was already too optimistic. Hoffard and Moorman, BPA, E-BPA-51R, 5.

WPAG argues that BPA's analysis does not address the question of whether the customer charge altered the probability of individual DSI customers leaving the region. Hutchinson, et al., WPAG, E-WA-01S, 10. While the analysis did not include explicit assignments of probabilities, the information from this analysis and others was provided to BPA's decisionmakers, who weighed the risk associated with BPA’s "exposure" under various conditions and concluded that BPA would be better off without the customer charge. Moorman, BPA, TR 3818-21. This conclusion is based in large part on the assumption that depressed or fluctuating aluminum prices are likely during the rate period. Companies striving to enhance their financial position would consider such potential aluminum price scenarios and the firms' resulting net cash flows in making decisions concerning the operation of regional smelters. Melton, BPA, E-BPA-365, 3.

[page 221]

BPA's decision concerning the customer charge also relied on a third analysis, a comparison between BPA's loads and revenues (1) with the customer charge, assuming some regional plants were closed, and (2) without the customer charge but assuming all plants remained in operation. This third analysis concludes that BPA's loads and revenues over a 5-year period would be lower if regional plants closed in the presence of the customer charge than if the customer charge were eliminated and all plants remained in operation. Melton, BPA, E-BPA-36S, 2-3.

NWU contends that this third analysis relies on the assumption that a number of smelters would close purely as a result of the customer charge. NWU asserts that BPA’s conclusions would not hold either if all plants remained open with a customer charge or if "closing smelters would have closed in any case." Wolverton, et al., NWU, E-NU-10, 12. In addition, NWU concludes that BPA could lose approximately 9 percent of its expected loads to permanent plant shutdowns caused purely by the customer charge and still be better off. Id. at 14. Further, NWU argues that elimination of the customer charge would result in a short-run revenue loss of as much as $200 million, which should be viewed as a "gift" to the DSIs because nothing is received by BPA and the other parties in exchange. Reply Brief, NWU, R-NU-01, 23-25. WPAG echoes NWU’s criticism, adding that the assumption that plants would close as a result of the customer charge is not quantified or supported and that, since the analysis is driven by that assumption, the result of the analysis is merely a reflection of an unverified assumption. Hutchinson, et al., WPAG, E-WA-01S, 10; R-WA-01, 7-9. OPUC/WUTC contends that BPA's revenues would fall by $200 million during the rate period if the customer charge were removed. White and Rolseth, OPUC/WUTC, E-OP/WU-01S, 9.

BPA disagrees with these arguments. BPA's analysis of discounted cash flows with and without the customer charge, as well as observation of industry operations in other regions faced with customer charges and consultation with industry analysts, concludes that a significantly higher risk of regional smelter closures exists with the customer charge than without. Observation of smelter closures in the TVA region is instructive. BPA's power rates combined with higher transportation costs place regional producers in similar circumstances. Hoffard and Moorman, BPA, E-BPA-51R, 4. Since the 1983 rate filing, BPA has concentrated on understanding the aluminum companies' long-run decisions, such as capacity expansion investments and plant closures. BPA’s own analysis, as well as information from others, suggests that there is reason for concern over permanent closure of several regional smelters. Hoffard and Moorman, BPA, E-BPA-10S. The critical assumption is the increased risk, not that the customer charge would be the sole cause of closure. Hoffard and Moorman, BPA, E-BPA-51R, 6. In addition, since the plant closures include at least two and perhaps as many as five regional smelters, BPA's exposure to reductions in loads and revenues is significantly greater than the "break-even" risk that NWU cites. Hoffard and Moorman, BPA, E-BPA-51R, 7. The potential losses if regional plants close as a result of the customer charge are significantly greater than the $200 million cited by NMW and OPUC/WUTC. Hoffard and Moorman, BPA, E-BPA-51R, 4. The DSIs argue that the customer charge is counter-productive. Initial Brief, DSI, B-DS-01, 104. The
[page 222] DSIs also assert that a customer charge exacerbates the already limited operating options for a DSI plant, there by promoting termination as the most economic course to follow. Initial Brief, DSI, B-DS-01, 102.

***Long-Run Prices and Regional Smelter Operations***

Another consideration regarding the customer charge is that BPA's assessments of current and expected conditions in aluminum markets became more pessimistic after the initial proposal. Melton, BPA, E-BPA-365, 1. This change was a result of a number of factors, including significant reductions in forecasted long-term aluminum prices and concern about increasing volatility of those prices. *Id*. at 3. The reductions in forecasted aluminum prices resulted primarily from reductions in forecasts of underlying demand for aluminum, combined with the continuing development of new low-cost smelting projects. The addition of new smelting projects at the lower end of the industry supply curve may force some existing smelters to become "swing" plants. Furthermore, there is a tendency for operating rates elsewhere to remain high even in the face of low aluminum prices. Melton, BPA, E-BPA-36S, 3; Hoffard and Moorman, BPA, E-BPA-10S, 4-5.

NWU disagrees with several aspects of BPA's assessment of aluminum market developments, including long-run equilibrium prices, comparative plant costs. price volatility, high operating rates as a result of "social policy" affecting smelters in other countries, additions of new smelters to world supply curves, and the implications of decisions by ARCO and Martin-Marietta to leave the industry. Wolverton, et al., NWU, E-NU-10, 16-29. NWU states that aluminum companies have been building new plants that range in cost from 75 cents to 85 cents/lb. and concludes that companies must expect prices in that range in order to yield a competitive return on investment. Wolverton, NWU, E-NU-02, 5. The analysis is based on testimony regarding the production economics of the Portland (Victoria, Australia) aluminum smelter. McCullough, NWU, E-NU-03. However, NWU's analysis fails to discuss a number of significant aspects of this project and the underlying contractual arrangements between ALCOA and the Victorian State Government, which make it impossible to conclude simply that the costs anticipated for this smelter reflect the company's price expectations. NWU has neglected to consider government loans, an alumina contract, government purchase of assets, and forgiveness of "delay payments." Hoffard and Moorman, BPA, E-BPA-51R, 12, 17; Initial Brief, DSI, B-DS-01, 103-104. In addition, NWU did not actually estimate or report the production costs from the Portland smelter, but merely equated them to a price assumption made by the Victoria Government. Reply Brief, DSI, R-DS-01, 58-59. NWU agrees that the construction of the Portland smelter may be encouraged by "hidden subsidies." Initial Brief, NWU, B-NU-01, 45. Even if the costs of the project cited do reflect ALCOA's price expectations, a conclusion which is not foregone, the costs would not necessarily reflect the expectations of other aluminum firms. In any event, the costs do not provide a good basis for BPA forecasting and planning because, as the utilities themselves state, "the firm’s expectations of price may be erroneous when viewed from a better perspective." Wolverton, NWU, E-NU-02, 3; Hoffard and Moorman, BPA, E-BPA-51R, 12.

[page 223]

NWU asserts that the "tendency for aluminum to be more of a social metal" will not affect the equilibrium price of aluminum. Wolverton, et al., NWU, E-NU-10, 21. "Social metal" refers to greater government involvement in aluminum production. NWU argues that aluminum's "social" aspect affects only the speed at which the market moves toward long-run equilibrium price. Wolverton, et al., NWU, E-NU-10, 22. NWU agrees, however, that some plants could be run for "social considerations" that might otherwise not be run. Wolverton, NWU, TR 4797. This would lead to higher market output and lower price. If such decisions result from the assignment of lower opportunity costs to the capital invested in the plants in the long-run, then the supply curve and equilibrium price in the long-run will also fall. Wolverton, NWU; TR 4796.

NWU dismisses volatility of aluminum prices as a reason for changes in current and expected conditions in aluminum markets because BPA presented no evidence that price volatility affects the expected level of aluminum prices. Wolverton, et al. , NWU, E-NU-10, 22. However, while greater volatility may not affect the average aluminum price over time, and perhaps not the expected value (i.e., probability-weighted average of possible outcomes) for a given point in time, it does increase the risk that the price will be lower than expected. It is prudent to assume that aluminum firms will be conservative in forecasts of prices and related matters, and is appropriate to consider this potential conservatism when developing industry forecasts. Hoffard and Moorman, BPA, E-BPA-51R, 18-19.

NWU asserts that BPA's assumption that "new low-cost smelting projects … will be added to the lower end of the industry supply curve" (Melton, BPA, E-BPA-36S, 3) is in accurate and that material provided by BPA supports the NWU position. Wolverton, et al., NWU, E-NU-10, 22-23. NWU's argument that there are no new low-cost smelting projects to be added to the lower end of the industry supply curve apparently refers to a long-run supply curve based on total costs while BPA’s assumption concerns a short-run supply curve based on variable costs, and its impact on the operation of PNW plants. Hoffard and Moorman, BPA, E-BPA-51R, 19. BPA's assumption is supported by NWU's own testimony concerning new smelters that "operating costs are lower for these new smelters so that, once completed, these plants will likely displace higher operating cost facilities such as some of those in the Northwest." Wolverton, et al., NWU, E-NU-10, 22.

NWU asserts that BPA's assumptions concerning potential closure of regional smelters were incorrect, because "some of the plants in the Northwest seem to have relatively high net present value… Comalco offered to purchase the Goldendale plant and additional assets for approximately $400 million." Wolverton, et al., NWU, E-NU-10, 25. In addition, NWU contends that Martin - Marietta's plants at "Goldendale and The Dalles both have similar technology and are of a similar age", so that "if the Goldendale plant has a positive net present value, it is likely that The Dalles plant has a positive net present value." Wolverton, et al., NWU, E-NU-10, 26. Comalco seems primarily interested in purchasing Martin-Marietta's rolling mill in Lewisport, Kentucky, to allow entry to the semi-fabricated products market in [page 224] the U.S. The Goldendale plant should be considered an asset that Comalco would have been willing to acquire even if it had little or no net present value. In addition, the two plants mentioned by NWU are not of a similar age and technology, so any conclusion reached about the Goldendale smelter does not necessarily apply to the other plant. The Dalles' size, age, and operating characteristics make it significantly less attractive than Goldendale. Hoffard and Moorman, BPA, E-BPA-51R, 21-22.

NWU asserts that the permanent closure of a regional smelter is not likely for any reason. Wolverton, et al., NWU, E-NU-10, 14. However, recent events in the aluminum industry indicate a strong possibility of at least one regional smelter closing permanently. At the time BPA prepared its analysis, ARCO and Martin-Marietta, owners of three of the ten regional smelters, had announced their intention to leave the aluminum industry. *Id*. The three plants had been for sale individually or collectively for at least three years, and only one had generated a firm offer. Both companies have indicated their intent to close the facilities if they are not sold. Since that time, Martin Marietta did close one of the smelters and is still trying to sell it. In addition, smelter closings have occurred elsewhere in the world in recent years as the industry has adjusted to slower demand growth, lower prices than expected, and changing relative power rates. These factors suggest that it is reasonable to assign a probability to some smelter closures in the region that is significantly greater than zero, contrary to the NWU's assertion. Hoffard and Moorman, BPA, E-BPA-51R, 8.

Finally, the customer charge may provide a disincentive for investment in the region's DSI plants, particularly the aluminum smelters. Melton, BPA, E-BPA-36S, 1. NWU disagrees with this concern, arguing that since the customer charge encourages higher capacity utilization, it could actually Act as an incentive to investment. Wolverton, et al., NWU, E-NU-10, 15-16. Nevertheless as the NWU themselves indicate in their testimony, the customer charge can increase the incentive to close a marginal plant. Initial Brief, NWU, B-NU-01, 73. The increased probability of a plant closure provides a disincentive for investment because it decreases the likelihood that the plant will be operated long enough to recover the investment. Hoffard and Moorman, BPA, E-BPA-51R, 9.

## Decision

*Because BPA is concerned about the risk of additional aluminum smelter closures and the resulting loss of revenues, a customer charge is not included in the IP-85 rate. Based on a pessimistic price outlook and other analyses, BPA concludes that lower and more cyclical aluminum prices, coupled with the addition of lower-cost capacity, will lead to more frequent and larger fluctuations in operating levels of regional plants. This in turn means that, faced with the prospect of a customer charge that increases the cost of operation when output is reduced, smelter owners/operators facing a customer charge would be more likely to close a plant permanently. Conversely, with the customer charge eliminated the plants are less likely to close even though they might operate at lower levels in the short-term. Melton, BPA, E-BPA-36S, 7-8.*
[page 225]
*For a given level of industry capacity, elimination of the customer charge could result in lower loads and revenues in the short run. However, this result must be considered with the effects of the customer charge on the level of industrial capacity over the long run. BPA's analyses demonstrate that under conditions that are reasonably expected, the customer charge will make the DSIs and BPA substantially worse off.*

## Issue #2

*Should the IP-85 rate schedule include a short-term incentive rate?*

## Summary of Positions

In BPA's initial proposal, a short-term DSI incentive rate was continued from the IP-83 rate. BPA, E-BPA-08, 54, 58, 323-328. NWU and WPAG previously supported offering incentive rates to the DSIs. This support was contingent upon what they considered to be a "balanced" approach to DSI rate design, including both a customer charge and an incentive rate. Beckmeier and Heinrich, NWU, E-NU-01, 4; Reply Brief, NWU, R-NU-01, 27; Hutchison, et al., WPAG, E-WA-01, 7. NWU and WPAG both later withdrew support for an incentive rate provision in the IP-85 rate schedule. Wolverton, et al., NWU, E-NU-10, 1; Hutchison, et al., WPAG, E-WA-01S, 3. The elimination of the customer charge, the revision of the floor rate, and NWU's perception that BPA has reduced the procedural protection associated with implementation of the IP-85 incentive rate from that associated with the IP-83 incentive rate caused the NWU to reverse their position. Wolverton, et al., NWU, E-NU-10, 1. WPAG at first stated that the reason for withdrawing support for an incentive rate was due to its assessment that by revising the DSI floor rate BPA ignored the assurances made by the Administrator that the adoption of an alternative rate would not harm BPA's other customers. Further, a lower DSI floor rate eliminates the need for an incentive rate. Hutchison, et al., WPAG, E-WA-01S, 4. With the adoption of the methodology for determining the floor rate described in section A, WPAG has returned to its earlier position. That is, WPAG supports a properly constructed incentive rate coupled with a customer charge. Reply Brief, WPAG, R-WA-01, 13. The DSIs argue that continuation of a provision to allow short-term incentive rate offers may be necessary to maintain DSI loads and protect BPA's revenues. The DSIs support retaining the short-term incentive rate and eliminating the customer charge. Initial Brief, DSI, B-DS-01, 109; Reply Brief, DSI, R-DS-01, 55.

**Evaluation of Positions**

In the initial proposal BPA included two mechanisms in the IP rate schedule to enhance BPA's revenue stability and promote short-run stability and efficiency of DSI operations: the customer charge and the incentive rate. Melton, BPA, E-BPA-36, 3. The customer charge was later found to be contrary to both of these desired goals. That is, the customer charge could reduce BPA's revenues and increase the risk of potential plant closure over the long run. A short-run incentive rate offer would not completely mitigate
[page 226] this risk. As such, BPA proposed eliminating the customer charge. For further discussion, *see* Issue #1 above. Nevertheless, an incentive rate within the IP-85 rate schedule does allow BPA the flexibility to respond to soft market conditions for aluminum. Melton, BPA, E-BPA-36, 4. The purpose of the incentive rate option is to address revenue instability caused by DSI load homogeneity and aluminum price volatility. Melton, BPA, E-BPA-36, 16.

NWU recognizes that an incentive rate has merit. "It allows BPA to maximize its revenues by reducing losses due to aluminum smelter load fluctuations, thus making it better able to meet its fiscal responsibilities than if it had not implemented the rate in the short run. The incentive rate provides an opportunity for aluminum smelters to achieve a higher level of production and employment than would be achieved in the absence of the Incentive rate." Initial Brief, NWU, B-NU-01, 83. However, NWU states that these merits can only be realized if the incentive rate is used in conjunction with the customer charge and is properly designed. Reply Brief, NWU, R-NU-01, 27.

WPAG and NWU supported a DSI rate containing both a customer charge and a short-term incentive rate. These two rate elements together represented in their view a "balanced approach" to reduce DSI load volatility, thereby ensuring a "steady revenue stream" from the DSIs. NWU argues that the elimination of the customer charge changes the economics of the incentive rate, making an incentive rate offer more difficult. With a customer charge, a DSI can avoid only a portion of its power cost by curtailing production. However, without the customer charge, a DSI would be able to avoid its full cost of power by shutting down production. BPA will have to offer a much larger discount to induce the DSIs to maintain operations in the face of falling aluminum prices. O'Meara, NWU, E-NU-05, 10; Wolverton, et al., NWU, E-NU-10, 7. Because of the relationship between the customer charge and the incentive rate, NWU states that implementing one without the other can lead to the DSIs receiving a rate benefit at BPA's and the other customers' expense. Initial Brief, NWU, B-NU-01, 79; Reply Brief, NWU, R-NU-01, 27.

NWU argues that the customer charge would serve to minimize the level of the discount offered. Revenues received from the customer charge also provide a limit on the amount of the discount that meets the revenue standard. Initial Brief, NWU, B-NU-01, 80, 85, and 87-89; Reply Brief, NWU, R-NU-01, 27. The customer charge in effect establishes a lower limit for the incentive rate. Hutchison, et al., WPAG, E-WA-01, 13. Also, with a larger discount and without a customer charge, BPA would have to assume more risk when making an incentive rate offer. Errors in the incentive rate study itself or unexpected occurrences will therefore have a greater impact on BPA's financial situation. O'Meara. NWU, E-NU-05, 19. Without the protection provided by the customer charge and the appropriate rate design, the incentive rate is inconsistent with sound business principles, will increase BPA's other customers' rates, and will

impair BPA's ability to meet its financial obligations. Reply Brief, NWU, R-NU-01, 27. The DSIs counter that no link between the customer charge and the incentive rate exists. The adverse effects of the customer charge cannot be overcome by a short-term incentive rate. Initial Brief, DSI, B-DS-01, 108-109.
[page 227]
With the elimination of the customer charge, the incentive rate is now the only mechanism currently available to BPA to provide short-run revenue protection in the event of soft aluminum prices. The incentive rate option is extremely important during the present period of depressed aluminum prices. Reply Brief, DSI, R-DS-01, 55. Eliminating the customer charge serves to increase rather than decrease the value of the incentive rate. As the DSIs note, "[i]t is highly unlikely, given the volatility of aluminum prices, that any base rate the Administrator adopts in this proceeding will be adequate to maintain full production during extremely adverse markets. By its very nature, the incentive rate enhances BPA's revenues, thereby benefiting all BPA's customers and reducing the losses incurred by the DSIs." Initial Brief, DSI, B-DS-01, 107.

The existence of the incentive rate option does not necessarily guarantee that it will be implemented or adopted. The incentive rate procedures do not provide any assurance that an incentive rate will be offered if aluminum prices are at a very low level. Melton, BPA, TR 3823. NWU agrees that the DSIs have no assurance that a particular incentive rate will ever be implemented. O’Meara, NWU, TR 4809. As stated by the DSIs, the rate is offered only at BPA's discretion and upon a finding that BPA revenues will not decrease. "Obviously conditions in both the aluminum and nonfirm power markets must coincide before an incentive rate is even possible." Initial Brief, DSI, B-DS-01, 109.

Finally, the United States Court of Appeals for the Ninth Circuit recently recognized that BPA has the rate flexibility to deal with special economic circumstances which may arise in the region. In *Portland General Electric Co. v. Johnson*, the Court stated:

> A certain latitude must be allowed within which BPA can exercise a degree of business judgment with respect to temporary situations… [W]e are influenced by the extraordinary conditions that led BPA to undertake the challenged transactions, by the need for prompt action by BPA, by the short-term, interim nature of the transactions, by the fact that BPA did solicit, accept, and consider public comment on its proposed Action, and especially by the fact that the transactions benefitted all of BPA's customers while harming none.

*Portland General Electric Co. v. Johnson*, No. 83-7546, slip op. at 15 (9th Cir. March 4, 1985). The court did request, however, that BPA build provisions for emergency variations in rates into the rate structure that BPA develops during ratemaking hearings and submits to FERC. Id., slip op. at 20. BPA is complying with that request.

**Decision**

*The incentive rate option is retained in the IP-85 rate schedule. The benefits of the incentive rate should not be lost by tying it to the customer*
[page 228] *charge. Eliminating the customer charge makes the incentive rate more valuable to promote BPA’s revenue stability goals.*

**Issue #3**

*What is the relationship between the IP-85 incentive rate and the section 7(c)(2) floor rate?*

**Summary of Positions**

In the initial proposal, BPA proposed that the IP-85 incentive rate could be lower than the IP-85 Standard rate if the lower rate increased BPA's total revenues. BPA, E-BPA-08, 58; Melton, BPA, E-BPA-36, 16. As such BPA and all of its customers stand to benefit even if the incentive rate falls below the floor rate. Melton, BPA, E-BPA-56R, 3. NWU argues that the floor rate applies to all rates charged the DSIs. Therefore BPA is "prohibited from selling power below the floor whether or not the incentive rate is in effect." O'Meara, NWU, E-NU-04, 7. PSP&L and OPUC/WUTC concur with NWU. Initial Brief, PSP&L, B-PS-01, 7; Reply Brief, PSP&L, R-PS-01, 9; Reply Brief, OPUC/WUTC, R-OP/WU-01, 11. WPAG states that the protection afforded the other customers by the floor rate must not be destroyed by short-term DSI rate concessions. If an incentive rate is "indiscriminately" offered below the floor rate, this protection is lost. Hutchison, et al., WPAG, E-WA-01, 11. Both NWU and WPAG suggest that the only way a temporary rate reduction can be reconciled with the floor rate protection is to provide for a mechanism to collect the revenue lost by this action when market conditions improve. O'Meara, NWU, E-NU-04, 4; Hutchison, et al., WPAG, E-WA-01, 11.

**Evaluation of Positions**

WPAG states that the "relationship between the floor rate and a short-term incentive rate is of utmost importance." Hutchison, et al., WPAG, E-WA-01, 11. They argue that the floor rate provision was included in the Northwest Power Act to protect all of BPA's customers during the transition from a cost-based DSI rate to an equity-based DSI rate. This protection would not be provided if an incentive rate allows the DSIs to purchase power at a rate below the floor rate. Hutchison, et al., WPAG, E-WA-01, 11. NWU, PSP&L and OPUC/WUTC concur with this position, stating that "BPA is prohibited from selling power below the floor, whether or not the incentive rate is in effect." O'Meara, NWU, E-NU-04, 7; Initial Brief, PSP&L, B-PS-01, 7; Reply Brief, PSP&L, R-PS-01, 9; Reply Brief, OPUC/WUTC, R-OP/WU-01, 11-12.

NWU and WPAG are incorrect. Under certain economic conditions offering the DSIs an incentive rate below the floor rate may enhance the protection afforded non-DSI customers by the floor rate, rather than erode that protection. The incentive rate allows BPA the flexibility to respond to soft aluminum markets by offering a lower rate when such a rate increases BPA's revenues. To implement the incentive rate, BPA must make a determination of its total expected revenues if the DSIs continue to purchase at the
[page 229] floor-constrained Standard rate. These revenues are then compared to the revenues BPA would receive if an incentive rate were implemented. An incentive rate offer will be made only upon a demonstration that it results in an *increase* in BPA's total revenues. This demonstration is subject to examination by BPA customers and other interested parties. BPA and all its customers stand to benefit even if the incentive rate implemented is below the floor rate. BPA will collect more revenues through the incentive rate offer than if the "floor-

constrained" Standard rate had remained in effect. By this Action, BPA will mitigate a potential revenue recovery problem that would affect all BPA's customers, not just the DSIs. By collecting more revenues, the incentive rate offer actually provides BPA's other customers greater protection than they would otherwise receive. Melton, BPA, E-BPA-56R, 3. The Incentive rate "increases rather than erodes" the floor rate protection. Reply Brief, DSI, R-DS-01, 56.

As noted above, the Ninth Circuit recently ruled that BPA must be allowed latitude to exercise a degree of business judgment with respect to temporary situations. That Court specifically found:

> If that energy could be sold, however, even at a rate lower than BPA normally charged the DSI's, it would produce revenues that could help BPA meet its obligations to the United States Treasury, and potentially lead to a future reduction in rates to all of BPA's customers. Moreover, if the energy were sold at a rate low enough to induce the restarting of idle industrial capacity, unemployed workers could be rehired and the ailing economy of the Pacific Northwest would receive a needed boost. Given these circumstances, *it was in the interest of all parties* that BPA enter into the challenged action.

*Portland General Electric Co. v. Johnson*, No. 83-7546, slip op. at 16 (9th Cir. March 4, 1985) (emphasis added). The result of implementation of the proposed incentive rate is a net benefit to BPA's non-DSI customers over what they would have received at the Industrial Standard rate. Puget argues that the decision in *Portland General Electric Co.* does not mean that "BPA can disregard the basic rate directives of the Regional Power Act." Reply Brief, PSP&L; R-PS-01, 9-10. Puget ignores the fundamental "rate directive" of section 7(a) of the Northwest Power Act: BPA must repay the U.S. Treasury. BPA must read the floor rate provisions of section 7(c)(2) in harmony with section 7(a) directives to recover sufficient revenues to repay the U.S. Treasury. The court in *Portland General Electric Co.* recognized this specific type of harmony when it approved BPA's sale "even at a rate lower than BPA normally charged the DSI's … [to] produce revenues that could help BPA meets its obligations to the United States Treasury, and potentially lead to a future reduction in rates to all of BPA's customers." Slip op. at 16.

Specifically, BPA has an obligation under section 7(a) of the Northwest Power Act to set rates to produce revenues that allow BPA to meet its
[page 230] obligations to the United States Treasury. BPA views the DSI incentive rate as a business like mechanism that will allow BPA to minimize financial losses during economically depressed conditions. After the IP Standard rate is set, the protection afforded non-DSI customers consists of revenues anticipated at any given time at the floor-constrained Standard rate. Thus, when economic circumstances arise that depress BPA revenues at the Standard rate, the appropriate decision facing BPA is whether revenues BPA anticipates under the floor-constrained Standard rate will be less than those that BPA would expect under the incentive rate.

WPAG and NWU propose a mechanism whereby both the short-term incentive rate and the protection derived from the floor rate provision can be achieved. They propose establishing a mechanism to account for the difference between revenue received under the incentive rate and the revenue that would have been collected for the same load at the floor rate. This difference would be collected later when market conditions improve. WPAG proposes establishing a "Floor Rate Deficit Account" that would track this revenue difference. Three months after the incentive rate terminates, payments would be made by the participating DSIs to reduce this account. The level and amount of these payments would be tied to the current price of aluminum and the amount of energy purchased during that month. Hutchison et al., WPAG, E-WA-01, 12. The NWU proposal is similiar [sic] in concept to WPAG's. NWU proposes that the incentive rate offer would include a promissory note obligation that would repay, with interest, the revenues lost by offering a rate below the floor rate. O'Meara, NWU, E-NU-04, 7-8. This proposal is misguided. WPAG admits that "the incentive rate proposed by Bonneville as purely defined -- if all the studies are done accurately -- does not result in specific lost revenues." Hutchison, WPAG, TR 4297. WPAG further acknowledges that if the incentive rate does not decrease BPA revenues, then the short-term incentive rate revenues will not be below the revenues collected under the floor rate. Hutchison, WPAG, TR 4299.

The ultimate effect of the NWU and WPAG proposals is to destroy the effectiveness of the incentive rate offering a lower take-or-pay rate on a short-term basis when market conditions are depressed, only in exchange for a higher rate later, greatly reduces the likelihood that such a rate can in fact be implemented. Such an arrangement is similiar [sic] to a loan. This might be effective if an aluminum company were reducing its level of operation solely because of cash flow difficulties. However, it does virtually nothing to change the underlying economics driving the decisions concerning plant operating levels. Thus, the DSIs would have essentially no incentive to enter into an agreement subject to these stipulations. Depending on the DSIs' internal discount rate (s) the payback provision could eliminate any benefits of the incentive rate. A DSI decision to enter into a take-or-pay arrangement will naturally compare the benefits derived from a lower rate with the financial risks inherent in a take-or-pay arrangement. A payback provision reduces the benefits and may increase the financial risk, reducing the likelihood that any incentive rate could ever be implemented. Melton, BPA, E-BPA-56R, 3.

[page 231]

**Decision**

*The incentive rate provisions will enable BPA to offer the DSIs a rate on a take-or-pay basis that is lower than the IP-85 Standard rate if such a rate will increase BPA's total revenues, even if such a rate may temporarily dip below the floor rate. The protection provided BPA's other customers under the incentive rate offer is equal to if not greater than the floor rate protection since the revenue comparison is made in consideration of the floor-constrained Standard rate. Any incentive rate offer under the IP-85 rate schedule will not be contingent on any payback provision.*

**Issue #4**

*How should the incentive rate be determined?*

**Summary of Positions**

The incentive rate is a formula rate determined by following a set of procedures contained in the General Rate Schedule Provisions (GRSPs). The impacts of a lower rate on loads and BPA's total revenues are considered in these procedures. BPA, E-BPA-08, 59. The proposed IP-85 incentive rate procedures published in the initial proposal incorporated the process employed to implement the IP-83 incentive rate. One of the language changes proposed by BPA explicitly recognizes the risks for both BPA and the DSIs in agreeing to a lower take-or-pay rate. This change allows BPA to consider the "risk premium" faced by the DSIs to determine both the level of the discount and the level of minimum load commitment that has the greatest likelihood of being realized in order to maximize BPA's revenues. Melton, BPA, E-BPA-36, 16. WPAG and NWU state that the incentive rate must maximize BPA's revenues. Initial Brief, WPAG, B-WA-01, 11; Reply Brief, WPAG, R-WA-01, 13; O'Meara, NWU, E-NU-05, 8; Initial Brief, NWU, B-NU-01, 79, 90; Reply Brief, NWU, R-NU-01, 27. APAC agrees. Reply Brief, APAC, R-PA-01, 27. If a "risk premium" is to be considered, it should be a numerical quantification that is documented and defensible. O'Meara, NWU, E-NU-05, 11.

**Evaluation of Positions**

In implementing the IP-83 incentive rate BPA recognized that the rate that is forecasted to maximize BPA's total revenues may not offer enough benefit to override the risks associated with a take-or-pay arrangement. However, BPA noted that a range of incentive rates and commitment levels exists that can provide this identical level of revenues. The difficulty is to determine the highest level of the rate that will provide enough benefit to bring forth the required level of committed load. In order for the incentive rate to maximize BPA's total revenues, the rate must be one that will be accepted by the DSIs. In considering whether to commit to a take-or-pay rate the DSIs must balance the benefits of the lower rate against the financial exposure such an arrangement presents. Melton, BPA, E-BPA-36, 17. Under a take-or-pay arrangement the DSIs bear all the financial risks of a downturn in the
[page 232] aluminum market. The incentive rate completely eliminates all flexibility for the DSI to reduce power cost, and imposes 100 percent liability for the committed load. On the other hand, under the Standard rate the DSIs face only the curtailment provisions in section 9(c) of the power sales contracts if market conditions deteriorate. The curtailment charge is only a percentage of the demand charges (beginning at 40 percent, then increasing to 90 percent and ultimately to 100 percent). The language in the GRSPs allows BPA to take this risk into account. Melton, BPA, E-BPA-36, 18-19.

The level of the incentive rate that increases BPA's total revenues and that can be realized will benefit all BPA's customers. See *Portland General Electric Co. v. Johnson* No. 83-7546, (9th Cir. March 4, 1985). If a lower incentive rate coupled with a higher load commitment achieves the same revenue level as a higher incentive rate coupled with a lower load commitment, then there is no revenue loss by adopting one rate over the other. However, the DSIs may be unwilling to commit on a take-or-pay basis to the higher rate given market uncertainties and expectations. If the lower rate has the greater potential of subscription than the higher rate, offering the higher rate could decrease BPA's total revenues if the DSI selected simply to curtail operations and remain at the Standard rate.

WPAG disagrees that BPA's other customers are in different to a lower rate and higher sales if this generates the same revenues from the DSIs. They point out that this ignores that BPA could have sold that additional power in an alternative market. BPA's other customers would not be harmed if BPA lowers the incentive rate to achieve a higher load commitment and that additional power could have been sold to the PSW at the NF Standard rate. Reply Brief, WPAG, R-WA-01, 15. However, WPAG's argument overlooks the fact that the incentive rate must increase BPA's total revenue taking into account nonfirm energy sales. Further, WPAG ignores the positive impact on PF sales due to the multiplier effect and potential future revenue benefits due to implementing the incentive rate.

The revenue loss associated with remaining at the IP Standard rate and conversely the revenue gain associated with the incentive rate may not be restricted only to that period in which the incentive rate is being considered. Even if aluminum prices rise in the future, there is a time lag between a change in price and the response to that change. Once a DSI has curtailed production, the costs associated with starting up a potline, combined with uncertainty about the duration of the price recovery, may preclude a quick response. A DSI response to a change in the price of aluminum is also affected by the magnitude and expected duration of the price increase.

NWU claims that BPA has abandoned the revenue maximization standard in place of the risk premium consideration. They assert that eliminating this standard will result in granting the DSIs a higher discount than necessary. In order for all of BPA's customers to benefit from the incentive rate, the revenue maximization standard must be applied to obtain the highest level of revenues from the DSIs. Reply Brief, NWU, R-NU-01, 28. APAC and WPAG agree [page 233] that without the revenue maximizing standard, there is no assurance that the incentive rate is in the region’s best interest. Reply Brief, APAC, R-PA-01, 27; Reply Brief, WPAG, R-WA-01, 14. When aluminum prices are low, BPA's revenues from the DSIs will decrease. Although the incentive rate may increase revenues from those expected under the Standard rate, it does not completely mitigate the revenue shortfall from low aluminum prices. The incentive rate recovers only a "*portion* of the financial loss". A larger discount only increases BPA's loss and the risk of meeting BPA's Treasury obligations. O'Meara, NWU, E-NU-08, 8; Initial Brief, NWU, B-NU-01, 90.

NWU does not agree that a greater discount in the form of an adjustment for risk is required to account for the burden imposed by the 6-month take-or-pay provision. They argue that the aluminum smelters have substantial incentives to maintain their operating status in the short-run because of the costs associated with turning a potline on and off. BPA agrees that this incentive may in some cases completely mitigate the risk associated with the take-or-pay arrangement. However, this may not always be the case. Instead of eliminating any consideration of the risk involved, both of these factors should be considered. NWU suggests that if a "risk premium" consideration is adopted, BPA should provide a quantified and documented estimate of this risk instead of merely asserting that one exists. O'Meara, NWU, E-NU-05, 11.

The DSIs state that the NWU "credits the incentive rate process with more precision than it warrants. There is no assurance that this process can find *the* rate level that maximizes revenues." Reply Brief, DSI, R-DS-01, 56. BPA concurs in part with the DSIs. A number of incentive rate and commitment levels are possible. NWU and WPAG appear to place full credence in the various models used in the incentive rate process to determine the rate that maximizes BPA's revenues. However, the models themselves do not and cannot capture all the relevant factors that should be considered in the incentive rate offer. Some of the considerations cannot be modeled or quantified. For instance, the ASM forecasts the expected load at various rate levels and not what the DSIs would be willing to commit to purchase under a take-or-pay arrangment [sic]. The ASM model also does not take into account the DSIs' incentive to maintain load by entering into an incentive rate arrangement because they avoid the costs associated with turning potlines on and off. In choosing among the incentive rate levels that increase BPA's total revenue, the Administrator must weigh the relevant factors influencing the offer, including those that are not part of the models.

**Decision**

*An incentive rate that increases BPA's total revenue and has the greatest potential for subscription will benefit all BPA's customers. A number of potential incentive rate levels exist that can result in an increase in BPA's total revenues during the incentive rate period greater than the revenues expected if the Standard rate were in effect during the same period. Not all of these incentive rate levels, however, have the same likelihood of being subscribed to on a take-or-pay basis. In deciding whether to commit to a lower rate, a DSI will weigh the benefits of a lower rate against the risks*
[page 234] *involved in a take-or-pay arrangment [sic]. BPA should also consider these same factors in choosing among the incentive rates to determine the highest rate level(s) with the greatest potential to be implemented. In addition, other factors may be relevant in deciding which incentive rate(s) to offer. These factors include the sensitivity of the results of the revenue analysis to small changes in assumptions and the potential revenue impacts beyond the incentive rate period if the rate is or is not implemented. In examining revenue impacts outside the incentive rate peiod [sic] some of the relevant considerations would include (a) the time lag for an orderly change in operating status (i.e., shutting down a potline or resuming operations after a shutdown); (b) the costs associated with bringing a potline up or taking one offline; and (c) the avoidance of a permanent plant closure. The incentive rate proceedures [sic] are modified to incorporate other considerations besides the risks associated with a take-or-pay arrangement. The decision as to which incentive rate level(s) to offer must balance a number of considerations, some of which are not easily modeled or quantified. The language in the GRSPs recognizes that the criterion of increasing BPA's total revenue can be met under a range of incentive rates and commitment levels. In the incentive rate determination, BPA will first identify those incentive rate levels that would increase BPA's total revenue from the expected revenues during the same period if the Standard rate were in effect. To select the highest incentive rate level(s) that will be offered, the GRSPs provide for consideration of other factors.*

**Issue #5**

*Should the IP-85 incentive rate offer provide for a minimum commitment level from each of the DSIs?*

**Summary of Positions**

The proposed GRSPs contained a provision requiring that the level of a DSI commitment for the incentive rate be equal to at least 90 percent of operating demand on the day the incentive

Rate Study is released. BPA, E-BPA-08, 284. The purpose of this provision is to ensure that each industrial customer that shares in the benefits of a lower rate also shares the risk of the take-or-pay arrangement. Melton, BPA, E-BPA-36, 19. The DSIs believe that this requirement may impede implementation of the incentive rate. Durocher, DSI, E-DS-08, 6; Initial Brief, DSI, B-DS-01, 107. NWU agrees with the DSIs that the 90 percent requirement may cause the incentive rate not to be implemented. As an alternative to BPA's proposal, NWU suggests that service under the incentive rate be limited to the committed load. Service above that level would be charged the Standard rate. O'Meara, NWU, E-NU-05, 13.

**Evaluation of Positions**

To implement the incentive rate BPA examines the load committed by each of the individual DSIs at the proposed incentive rate and determines whether the total level of commitment increases BPA’s total revenues. BPA recognizes that
[page 235] this could lead to a situation where an individual DSI might commit to a lower amount of purchases believing that the total commitment level will be sufficient to cause the rate to be implemented. This action could result in the incentive rate not triggering, even though the lower rate would have been beneficial to both BPA and the DSIs. To address this problem BPA proposed a requirement that the DSI level of commitment must be equal to at least 90 percent of its operating level on the day the Study is released. Melton, BPA, E-BPA-36, 19. The DSIs argue that the 90 percent requirement itself could hinder implementation of the incentive rate. Durocher, D51, E-DS-08, 6; Initial Brief, DSI, B-DS-01, 107. NWU concurs with this conclusion. "BPA's proposal could lead to an incentive rate offer not succeeding because a number of DSIs would be willing to subscribe at a high level, but not 90 percent of operating demand." O'Meara, NWU, E-NU-05, 14.

BPA acknowledges that the 90 percent limitation could lead to counter-productive results in some cases. Melton, BPA, TR 3827. First, forecasted aluminum prices could decline to a level during the incentive rate period under consideration where BPA’s ASM model may project that the DSIs' commitments will be less than 90 percent of the then current operating level. In fact, if the realized aluminum price levels had been predicted when the first IP-83 incentive rate offer was being considered, the DSI committed load level would have been less than the actual operating levels during the period. Moorman, BPA, TR 3824. Second, the price of aluminum affects the operations of each smelter differently at a particular price of aluminum some smelters would be able to operate and others would not. Given a period of declining aluminum prices, some smelters' operations that are profitable at the beginning of the incentive period could become unprofitable at some point within that period. Moorman, BPA, TR 3829-3830. A 90 percent requirement would adversely affect these smelters. However, the requirement would not have the same degree of impact on those smelters that could operate profitably throughout the period. A requirement that is not equally applicable to all of the DSIs may not be in BPA's best interest. Melton, BPA, TR 3830. A company that was harmed by the 90 percent limitation may not be willing to enter into a future incentive rate offer.

NWU proposes an alternative approach to deal with the "free rider" problem. They suggest that the incentive rate would be available only for the committed level of load. Any additional power above this amount would be available at the full Standard rate. O'Meara, NWU, E-NU-

04, 13. NWU states that this approach has several advantages. First, it provides an incentive for each DSI to make an accurate commitment to the amount of power to be purchased under the incentive rate. Second, it provides more flexibility than BPA's approach in that the DSIs are not constrained by current operating levels. O'Meara, NWU, E-NU-05, 14.

The NWU proposal has merit both administratively and economically. Nevertheless, this proposal is not without drawbacks. First, although the Primary purpose of the incentive rate offer is to minimize BPA’s potential revenue loss from the DSIs, it also serves to stimulate DSI operation. Charging the Standard rate for purchases above the committed level could serve [page 236] to prevent increases in operation above that level if the price of aluminum increases only slightly during the incentive rate period. This could cause BPA's revenues to be less then they could have been if all purchases were made at the incentive rate. Second, once an incentive rate is accepted, the DSIs assume all the risks for any downturns in the aluminum markets. It may not be reasonable also to prevent them from receiving benefits if the market improves over what was expected during the same period. Finally, the ability to take power above the commitment level at the incentive rate is a benefit to the DSIs and increases their collective incentive to achieve a commitment level high enough to allow implementation of the rate.

BPA agrees with NWU and the DSIs that the 90 percent limitation may be too restrictive and produce results that are unintended. The NWU proposal, although it has merit, may produce results that would be inappropriate in some situations. Therefore the rate schedules and GRSPs will not resolve the issue of whether the incentive rate or the Standard rate applies to purchases above the commitment level. Instead, this issue, as well as minimum commitment levels, will be addressed in the implementation of each incentive rate offer. NWU opposes a case-by-case determination leaving the resolution of any commitment level requirements to the implementation process. This would allow the DSIs to "manipulate" the incentive rate in their favor. Reply Brief, NWU, R-NU-01, 29. However, BPA has reserved the right to implement the NWG proposal in any incentive rate implementation process should circumstances warrant. As discussed above, NWU's proposal may not be appropriate in all situations. A case-by-case determination allows BPA to consider the most current conditions in any analysis of required commitment levels. The DSIs support establishing "appropriate conditions of sale based on the circumstances that exist when an incentive rate offer is made." Reply Brief, DSI, R-DS-01, 57.

**Decision**

*The rate schedules and GRSPs will not resolve the issue of whether the Incentive rate or the Standard rate applies to purchases above the commitment level. Nor will requirements for minimum commitment levels be included in the rate schedules and GRSPs. Instead these issues will be addressed in the implementation of each incentive rate offer.*

**Issue #6**

*Should the incentive rate be available for nonaluminum DSIs?*

**Summary of Positions**

The incentive rate is available for those industrial purchasers willing to commit to a take-or-pay arrangement. Although the decision to offer and the level of the rate depend in part on economic conditions in the aluminum market, the rate is not limited to aluminum companies. The proposed rate schedule does not contain language that would restrict the incentive rate [page 237] offer to aluminum smelters. See proposed IP-85 rate schedule (BPA, E-BPA-08, 170-194) and related GRSPs (BPA, E-BPA-08, 323-328). NWU argues that special reduced-rate offers should not be extended to the nonaluminum DSIs. O'Meara, NWU, E-NU-05, 7; Initial Brief, NWU, B-NU-01, 98; Reply Brief, NWU, R-NU-01, 30.

**Evaluation of Positions**

NWU objects to extending special rate discounts to nonaluminum purchasers. Some of these companies are involved in operations that directly compete with the industrial customers served by Northwest utilities. A discount to nonaluminum DSIs could erode the "competitive relationship within these industries." Initial Brief, NWU, B-NU-01, 99; Reply Brief, NWU, R-NU-01, 30. As noted by APAC, although the aluminum industry in the Pacific Northwest is facing financial difficulties, "other basic industries in the Pacific Northwest face equally stiff competition." Initial Brief, APAC, B-PA-01, 47. Nevertheless, APAC opposes granting a lower rate to the DSIs that directly compete with other industrial customers in the region. Reply Brief, APAC, R-PA-01, 27.

NWU also argues that a discount to these customers may not be required to increase BPA's total revenues. Initial Brief, NWU, B-NU-01, 99. The nonaluminums constitute less than 10 percent of the total DSI load. Because of their relatively small load, BPA's revenues are less harmed by fluctuations in the nonaluminum DSI load. Further, the nonaluminum DSIs' lack of homogeneity means that their loads do not fluctuate together. O'Meara, NWU, E-NU-05, 7. With the combination of these factors, the nonaluminum loads present less risk of revenue underrecovery than aluminum loads. Melton, BPA, E-BPA-36, 8.

BPA recognizes that a change in BPA's rates to the nonaluminum DSIs can affect the competitiveness of various industries. However, the competitive relationship is affected by any change in cost, of power or other factors. The fact that these industries are not as electricity-intensive as the aluminum smelters means that the price of electricity is not as critical in their decisions to operate, or in the determination of profitability. Because the companies in competition with the nonaluminum DSIs are not all located in the same utility service area the power costs to these industrial consumers already vary. The competitive status among these companies is also affected by other factors beyond the control of utilities. The impact of the power cost reduction depends on the relationship of power purchases from BPA to total costs. Finally, because the incentive rate offer is only a temporary cost reduction, it is highly unlikely to result in any long-term impact on the market price.

NWU argues that the incentive rate offer is tied to aluminum markets, and therefore offers to the nonaluminums may not comport with the purpose of a reduced rate. The incentive rate depends on economic conditions that affect aluminum loads and revenues. The market conditions facing the nonaluminums may not be identical to those in the aluminum market. Therefore, a reduced [page 238] rate to the nonaluminums may not result in an increase in loads and a corresponding increase in revenues. NWU concludes that "[w]hile an incentive rate offer may be necessary to maximize BPA's revenues from aluminum smelters, it may represent an unnecessary windfall to non-aluminums." Initial Brief, NWU, B-NU-01, 99; Reply Brief, NWU, R-NU-01, 30.

BPA agrees that the economics facing the nonaluminum DSIs may not coincide with the aluminum market conditions. A separate incentive rate process for the nonaluminums may warrant further attention. APAC has suggested that limiting the incentive rate to aluminum industries does not preclude offering the nonaluminums a lower rate. Any rate reduction for the nonaluminum DSIs should be addressed in conjunction with the separate 7(i) process BPA is considering for developing incentive rates for retail industrial customers in the region. Reply Brief, APAC, R-PA-01, 27. *See* Section C. BPA agrees that this issue would be appropriate in that forum. However, until BPA has a mechanism specifically available the for nonaluminum DSIs, the incentive rate in the IP-85 rate schedule will continue to be available to all industrial purchasers.

**Decision**

*The IP-85 incentive rate is available to all industrial purchasers willing to accept a take-or-pay arrangement.*

**Issue #7**

*Should BPA assess an unauthorized increase charge on offpeak loads?*

**Summary of Positions**

Prior to the 1983 rate filing, BPA could assess an unauthorized increase charge for DSI load overruns during both the peak and offpeak periods. In the 1983 wholesale power rate schedule, the unauthorized increase charge was restricted only to the peak period. In the 1985 proposal, BPA includes language that would again allow an unauthorized increase charge to be applied during both the peak and offpeak hours if a DSI operates above the requested and/or agreed upon level. Melton, BPA, E-BPA-36S, 5. The DSIs object to applying the unauthorized increase charge to offpeak use. Durocher, DSI, E-DS-08, 3; Durocher, DSI, E-DS-8S, 3; Initial Brief, DSI, B-DS-01, 110.

**Evaluation of Positions**

For the initial proposal, the language regarding the unauthorized increase charges was changed so that it was no longer restricted to Measured Demand during BPA's peak period. The change recognizes that BPA's operations depend in part on DSI Operating Levels made known in advance of actual operations. System problems caused by load overruns may occur in both the peak and offpeak periods. The unauthorized increase charge, therefore, should apply to all hours. Melton, BPA, E-BPA-36S, 5. The unauthorized increase charge serves to provide an incentive for the DSIs to operate during all hours at the level requested or agreed upon.
[page 239]

The DSIs assert that an unauthorized increase charge is not appropriate for offpeak use. They argue that this is contrary to BPA's rate principles for diurnally differentiated demand charges. Durocher, DSI, E-DS-3, 8. This statement, however, is unfounded and misrepresents the principle for diurnally differentiated demand charges. The principle behind diurnally differentiated demand charges is stated in the MCA. The MCA looks at planned cost incurrence over the long term. BPA, E-BPA-2, 19-20; Emery, BPA, E-BPA-22, 12. The unauthorized increase charge pertains to short-run operational problems caused by unexpected and unplanned load increases. Operational problems resulting from unauthorized load increases may occur during both the peak and offpeak periods. There are no measurable, perceived differences between peak and offpeak periods in this regard. Melton, BPA, E-BPA-36S, 5. The DSIs do not provide any quantified demonstration that such a difference exists. In fact, the DSIs recognize that "efficient scheduling and use of water releases require that BPA have for *all* hours the best possible forecast of loads that it must serve" (emphasis added). Durocher, DSI, E-DS-085, 3. The unauthorized increase charge provides an incentive for the DSIs to give BPA an accurate notice of the level of operations during all hours of the day.

The DSIs further argue that an unauthorized increase charge is unnecessary to prevent a DSI from using more energy than its entitlement because BPA can contractually impose a restriction on the load. Durocher, DSI, E-BPA-08, 3. BPA agrees that the DSI load can be restricted under certain conditions. However, unless BPA physically cuts the power, a DSI can continue to use energy above the restricted amount. The unauthorized increase charge applied to all hours provides a mechanism to impose a revenue penalty if a DSI continues to use energy in excess of its restricted demand.

The DSIs suggested that the language developed for imposition of the unauthorized increase charge during offpeak hours could be construed to mean that the offpeak demands would also be included in determining the DSIs' Billing Demands. Durocher, DSI, E-DS-08, 3. To eliminate this confusion, BPA deleted the language relating to a DSI submitting up to three levels of peak and offpeak demands and rewrote the language in the Unauthorized Increase section of the IP and SI rate schedules. Melton, BPA, E-BPA-36S, 5. The DSIs responded that the changes in the language are inappropriate and still create ambiguities. They disagree with eliminating the provision for establishing peak and offpeak schedules. The revised language for the unauthorized increase could result in some billing confusion. Durocher, DSI, E-DS-08S, 2. BPA agreed that the revised language was still unclear and that some modification may be required. Melton, BPA, TR 3832. The language is changed to address this confusion.

**Decision**

*The unauthorized increase charge applies to load increases above a level previously agreed upon in both the peak and offpeak hours. The reason for reinstating this provision is twofold. First, it provides an incentive for the DSIs to give BPA an accurate notice of the level of operations during offpeak hours. Second, it provides a mechanism to impose a revenue penalty if*

[page 240] *a DSI continues to use energy in excess of its restricted demand. Language to achieve these purposes is included in section V.B. of the IP-85 and section VI.B. SI-85 rate schedules as well as section III.A.10 of the the [sic] GRSPs.*

## Issue #8

*Should BPA adopt a DSI Contract Termination Adjustment Clause?*

## Summary of Positions

As part of a DSI rate package NWU included an adjustment clause that would adjust BPA's rates if an aluminum smelter permanently closed. The adjustment clause would calculate BPA's revenues lost due to the termination of a DSI smelter. These revenues would be recovered from all adjustable firm power and Standard nonfirm energy sales over the remainder of the rate period. The adjustment clause as proposed by NWU would go into effect within two months of the abandonment of a DSI power sales contract. O'Meara, NWU, E-NU-04, 3-4. WPAG also supports a Contract Termination Adjustment Clause to deal with the permanent loss of DSI firm load. As proposed by WPAG the adjustment would go into effect 1 month after the contract termination, provided the adjustment is greater than 0.1 mills per kilowatt hour. Hutchison, et al., WPAG, E-WA-01, 17. An adjustment clause for a DSI plant closure !s also endorsed by PGP. Opatrny, PGP, E-PG-08, 9; Reply Brief, PGP, R-PG-01, 32.

## Evaluation of Positions

NWU proposed a DSI rate design package that included a customer charge, a short-term incentive rate, and an "insurance policy" provided by a DSI Contract Termination Adjustment Clause (CTAC). This insurance policy is considered necessary because the customer charge/incentive rate combination does not protect BPA revenues in the event of a permanent closure of a smelter. Initial Brief, NWU, B-NU-01, 95. NWU agrees that in the long run a customer charge increases the risk of plant closure. Initial Brief, NWU, B-NU-01, 73. Although NWU does not generally support adjustment clauses, they believe that the utilities' commitment to recover the revenues lost if a DSI permanently closes a plant may dampen BPA's "preoccupation" with preventing marginal plants from terminating operation. They state that it is "important to reassure BPA that its ability to repay the Treasury will not be harmed if an aluminum smelter shuts down". O'Meara, NWU, E-NU-04, 1 and 5-6. NWU characterizes the CTAC as part of an overall DSI rate package. The individual components of this package are "inextricably intertwined and cannot be independently implemented without causing substantial harm to important interests." Initial Brief, NWU, B-NU-01, 69. NWU does not support the individual parts but rather the package as a whole. BPA has rejected one part of this package, the customer charge. See Issue #1, above. NWU withdrew support of the incentive rate with the elimination of the customer charge. Therefore it may be concluded that the NWU no longer supports a CTAC absent the customer charge.

WPAG also proposes a CTAC to address the permanent problem of a DSI contract termination. The mechanics of the adjustment clause proposed by both WPAG and NWU are similar. The adjustment clause calculates the revenues lost due to a DSI contract termination by multiplying the forecasted sales to that smelter(s) over the remainder of the rate period by the difference between the forecasted price of power when sold to a DSI and the price that same power would bring when sold in the nonfirm energy and surplus firm power markets. O'Meara, NWU, E-NU-04, 3-4; Hutchison, et al., WPAG, E-WA-01, 16. NWU proposes then to adjust this amount by subtracting the payment of damages caused by a DSI plant termination provided for in the power sales contracts. O'Meara, NWU, E-NU-04, 4. The remaining amount would be spread overall adjustable firm power rates as an energy adder component. Hutchison, et al., WPAG, E-WA-01, 17. The NWU proposal would also collect a portion of this amount from Standard nonfirm rate sales projected for the remainder of the rate period. O'Meara, NWU, E-NU-04, 3. The adjustment clause as proposed by NWU would go into effect within two months of the abandonment of the power sales contract. O'Meara, NWU, E-NU-04, 4. As proposed by WPAG it would go into effect 1 month after the termination of the power sales contract, provided the adjustment is greater than 0.1 mill per kilowatt hour. Hutchison, et al., WPAG, E-WA-01, 17.

BPA agrees that a CTAC provides some revenue protection against a DSI contract termination and thereby reduces BPA's exposure to revenue underrecovery. The CTAC attempts to minimizes the problems associated with the risk of a DSI plant closure. However, if the CTAC were implemented BPA's other customers' rates would increase. BPA is concerned with keeping its rates as low as possible. An alternative to the CTAC is to seek rate design measures that reduce the risk of DSI plant closure. BPA has accomplished this by eliminating the customer charge and retaining the incentive rate. Eliminating the customer charge reduces the risk that a DSI will terminate its contract. Retaining the incentive rate provides a mechanism that may encourage DSI production during soft aluminum markets. These DSI rate design measures will not increase BPA's other customers rates during the rate period.

The purpose of BPA's current adjustment clauses, and adjustment clauses generally, is to accommodate differences between the forecast and actual cost for major expense items without filing new rates. The CTAC does not comport with this purpose. Essentially, the CTAC is a variation of the load adjustment clause proposed by other parties and therefore presents the same generic computational problems. First, a timing problem exists between determining the cost associated with a DSI contract termination and recovering that cost from other sales. Second, the method for allocating these costs to BPA's other customers is unclear. And finally, the impact on other rates must be assessed, especially those rates designed to respond to marketing consideratons [sic]. These problems are also discussed in Section K.

The NWU proposal does contain a provision for a notice and comment period for BPA's other customers and interested parties. However, NWU is divided on whether the notice and comment procedure should be similar to those currently existing for the SSAC and incentive rate or whether a full 7(i) process and
[page 242] Federal Energy Regulatory Commission approval must be undertaken. O'Meara, NWU, E-NU-04, 4; Initial Brief, NWU, B-NU-01, 97. Conducting a full 7(i) process would weaken the rationale for including an automatic adjustment clause in the rate schedules.

**<u>Decision</u>**

*A CTAC provision is not adopted or included in BPA's firm power and Standard nonfirm rate schedules. Rate design measures that reduce the risk of plant termination are more appropriate and consistent with BPA's goal to minimize its wholesale power rates. The CTAC proposed by*

*NWU and WPAG suffers from the same generic computational problems as a load adjustment clause.*

**Issue #9**

*Should the IP rate schedule contain a long term DSI rate?*

**Summary of Positions**

In direct testimony, BPA stated that consideration would be given to a long-run incentive rate option available within the IP-85 rate schedule, possibly a rate structure that would tie the price of electricity to the price of aluminum for large industrial plants. BPA requested suggestions and comments from the parties on this rate option. Melton, BPA, E-BPA-36, 23-24. WPAG opposes consideration of a long term incentive rate in this rate proceeding. Hutchison, et al., WPAG, E-WA-01, 26; E-WA-2R, 10.

**Evaluation of Positions**

In designing rates for the DSI customers, BPA stated that one of its overall objectives was to promote the long-run viability of the DSI customers. As part of this overall objective, BPA indicated a long-run DSI Incentive rate option was under investigation. Melton, BPA, E-BPA-36, 4. At the time the initial proposal was filed, BPA was not prepared to propose a specific rate option. Nevertheless, BPA listed the general principles that would be considered in developing a long-run DSI incentive rate. If a long-run rate incorporating these principles was developed, BPA proposed to present it in supplemental testimony. Melton, BPA, E-BPA-36, 23-24. After supplemental testimony was filed, BPA announced that a separate process would be undertaken to examine various long-run DSI options. One of the options under consideration is an indexed or variable rate that would track aluminum prices. Melton, BPA, TR 3704-3705.

A careful analysis of any long term DSI policy is warranted. BPA is conducting a separate a DSI Options Study with an associated public involvement process. The goal of the Options Study is to determine how each of the various DSI options promotes the long-term viability of the DSIs in the region and how each affects BPA's revenue stability, load stability and the amount and distribution of FCRPS benefits to BPA's PNW customers. The Hearing Officer moved all testimony proposing long-run DSI incentive rates from the 1985 rate case to the DSI Option Study forum. See O-42, O-45.

[page 243]

The Hearing Officer ruled that moving these proposals to the DSI options study proceeding "would be administratively and judicially expedient: they are similar to the subjects being considered in the options case; BPA and the parties would be able to focus on the proposals since DSI long-run incentive rates are the sole subject in issue there; the expense and duplication of considering the same and similar subjects in concurrent proceedings will be avoided." See O-42.

**Decision**

*This rate proceeding has not established a record in support of adopting a long-term DSI incentive rate. Examination of various long term DSI rate options is taking place in an* *independent process. The DSI Options Study will explore the various social, economic, and environmental impacts of each option. If the results of the Study lead to a long term rate proposal, BPA will conduct the required 7(i) process before the rate will be effective.*

**Issue #10**

*Should BPA adopt a long term policy setting the IP demand and energy charges equal to the PF demand and energy charges?*

**Summary of Positions**

Following the rate directives contained in section 7(c)(2) of the Northwest Power Act, the IP Standard rate for industrial purchases after July 1, 1985 is based on the Administrator's "applicable wholesale rate" to BPA's public agency and cooperative customers plus a mark-up typical of those applied by these customers to their retail industrial consumers. This rate is then adjusted for the value of the reserves provided by BPA's right to restrict the DSI load for system reserve purposes. BPA, E-BPA-08, 56-57. Each of these components is separately determined. For this rate filing, the "applicable wholesale rate" is the Priority Firm Power demand and energy charges. See Chapter VI. The typical margin and the value of reserves are determined in separate studies. See Chapter VI and Chapter VIII, Section B, respectively. The DSIs suggest that the Administrator adopt and implement a long term policy in this rate filing to set the IP Standard rate demand and energy charges equal to those contained in the PF rate schedule. Initial Brief, DSI, B-DS-01, 67; Reply Brief, DSI, R-DS-01, 6.

**Evaluation of Positions**

The DSIs propose that the Administrator adopt and implement a long term policy whereby the charges in the IP Standard rate schedule are set equal to those of the PF rate schedule. The DSIs assert that this policy would not increase the PF rate, "will be beneficial to all of BPA's customers, will allow BPA to achieve important goals of the Regional Act, and is consistent [page 244] with the post-1985 rate directives and the Administrator's ratemaking discretion under the Act." Initial Brief, DSI, B-DS-01, 67. NWU maintains that the Administrator must set the DSI rates in strict accordance with section 7(c)(2) of the Northwest Power Act. Pre-hearing Brief, NWU, P-NU-01, 7; Initial Brief, NWU, B-NU-01, 5. The DSIs contend that this action would result in a higher rate than under the "strict application" of the rate directives contained in section 7(c)(2); however, most of the DSIs would be willing to trade the lower rate in exchange for rate stability and predictability. Initial Brief, DSI, B-DS-01, 68. It is not correct that the 7(c)(2) equitable rate is less than the PF rate schedule, although these values are reasonably close. The margin is 2.3 mills per kilowatthour compared to a VOR credit of 1.9 mills per kilowatt-hour. Thus the equitable rate is about 0.4 mill higher than the PF rate schedule. On the other hand, this differential is small enough that reasonably minor changes in assumptions or resolution of issues could reverse the relationship. The differential between the PF-85 and the IP-85 rate schedules is much larger because of the floor rate.

The DSIs argue that rates under "strict application" of the section 7(c)(2) rate directives are lower than the PF rate charges because the increase in the value of reserves credit will exceed the increase in the typical margin.  Initial Brief, DSI, B-DS-01, 67.  This is not intuitively obvious. The value of reserves cost has remained fairly stable since the adoption of the current methodology, with the level decreasing only slightly from 1981 to the current rate case.  The major cost associated with the value of reserves, the capital cost of the combustion turbine, is fixed and is not escalated.  Given that the value of reserves costs have not increased from 1981 to the present, but rather decreased, it is not clear that in the future the value of reserves will always exceed the typical margin.  The DSIs counter that even if this were not the case, the Administrator has the discretion to grant the DSIs more than 50 percent of the value of the reserves provided by BPA's right to restrict the DSI load.  Reply Brief, DSI, R-DS-01, 11.

Currently the "applicable wholesale rate" is based on the PF rate.  The NR rate would be included in this calculation if public agency and cooperative customers were purchasing power to serve new large single loads.  BPA, E-BPA-46, 22.  No new large single loads for public body or cooperative customers are forecast during this rate period.  Peters, BPA, E-BPA-33, 15. Including the NR rate in the "applicable wholesale rate" would change the relationship between the DSI rate and the PF rate.  The fact that BPA is not currently projecting any new large single loads for public agency and cooperative customers does not eliminate this possibility in the future.

The DSIs argue that setting the IP rate equal to the PF rate would reduce the instability and uncertainty associated with the section 7(c)(2) rate methodology.  Both the margin determination and the value of reserves analysis contain an inherent degree of uncertainty in the future.  The margin is subject to abuse by the utilities.  The value of reserves analysis does not acknowledge the first quartile of the DSI load for reserve purposes and does not ascribe to it a value.  Instead, the first quartile character of service
[page 245] is reflected in the margin.  However, this treatment of the margin could result in charging the DSIs a premium for first quartile service when the opportunity cost of nonfirm energy exceeds the cost of firm power.  Reply Brief, DSI, R-DS-01, 9.

The DSIs further argue that BPA's Northwest customers' debates over who pays what costs could be avoided if this long term policy were adopted.  This would allow the Northwest customers to focus on "controlling" the overall revenue requirement instead of focusing on the individual cost allocations.  Also, setting the DSI rate equal to the PF rate eliminates the "need to relitigate in each rate case the details of the margin and value of reserves."  Initial Brief, DSI, B-DS-01, 69.  BPA agrees that reducing the contentiousness of the rate case has merit.  Indeed, BPA does not intend to relitigate the details of the margin and value of reserves credit extensively in each rate case.  For example, the value of reserves methodology has not changed since the 1981 rate case, when alternative combustion turbines were assumed to have been built.

**Decision**

*At this time, BPA is not adopting a long-term policy of setting the IP rate equal to the PF rate schedule.  Instead, BPA has adopted a 7(c)(2) methodology that ties the IP rate closely to the PF rate schedule.  BPA agrees that there are major benefits to be gained by providing greater planning certainty to the DSIs, removing as much controversy and contentiousness from future rate cases as possible.  There also appears to be a willingness on the part of the utilities, as well* *as the DSIs, to develop a long-term policy that all parties could accept, which would allow all parties in the future to focus their efforts on common concerns and issues such as revenue requirement and rate design. It is unclear how this goal could be accomplished in the 1985 rate proceeding. A decision in this case to deem the VOR credit equal to the margin (which would have no affect on the rate because of the floor) could simply be rerversed [sic] in a later rate case. BPA is anxious to proceed with whatever actions may be necessary, outside of the 1985 rate proceeding, to facilitate the development and adoption of a long-term policy with respect to the determination of the relationship between the PF and IP rate schedules.*

## E. Special Industrial Firm Power Rate

BPA offers the Special Industrial Firm Power rate (SI-85) pursuant to section 7(d)(2) of the Northwest Power Act. In past wholesale power rate filings, only the Hanna Nickel Smelting Company (Hanna) applied for and was granted eligibility to be served under this rate schedule. In the 1983 rate filing, Hanna requested and received an Offpeak Period rate of 7 mills per kWh. The Offpeak Period rate applied to Hanna's contract demand taken in specified offpeak hours, and to an amount of power up to 10 percent of Hanna's contract demand taken during other hours of the week (1983 Rates ROD, 269-271).

[page 246]

### Issue

*Should BPA offer Hanna a 5-year contract option at the SI-85 Offpeak Period rate, and should Hanna be allowed to increase the amount of power it purchases outside its Offpeak Period from 10 percent to 15 percent of its contract demand?*

### Summary of Positions

Following the precedent set by the 1983 Industrial Hanna (IH-83) rate and assuming that Hanna would again request and be granted eligibility to receive service under such a rate, BPA proposed an SI-85 Offpeak Period rate of 7 mills. BPA, E-BPA-08, 39; Peters, BPA, E-BPA-41, 22-23. Hanna supports the SI-85 Offpeak Period rate of 7 mills. Pre-Hearing Brief, Hanna, P-HN-01, 1-4; Wedge, Hanna, E-HN-01, 3; Moke, Hanna, E-HN-02, 6; Initial Brief, Hanna, B-HN-01, 1 and 6-8. Hanna proposes that BPA offer Hanna a 5-year contract option at the SI-85 Offpeak Period rate. The offer would be contingent upon Hanna performing a capital improvement program to increase the efficiency of its ore recovery. Pre-Hearing Brief, Hanna, P-HN-01, 1 and 4-5; Wedge, Hanna, E-HN-01, 3 and 12-14; Moke, Hanna, E-HN-02, 6-8; E-HN-02S, 1-2; Initial Brief, Hanna, B-HN-01, 5. Hanna also proposes that it be allowed to increase its peak period service limit in order to implement a wet screening process to increase the efficiency of its nickel production. This proposal also is contingent upon implementation of the wet screening process. Wedge, Hanna, E-HN-01, 13; Moke, Hanna, E-HN-02, 6 and 14; Initial Brief, Hanna, B-HN-01, 6. BPA recognizes merit in Hanna's requests to receive a 5-year contract option under the SI-85 rate and to increase its peak period service to 15 percent of contract demand from 10 percent. Melton, BPA, E-BPA-56R, 4.

The PPC opposes the 5-year "rate guarantee" for Hanna. Wolverton and O'Meara, PPC, E-PP-04R, 9.

**Evaluation of Positions**

No party commented unfavorably on BPA's offer of the SI-85 7-mill Offpeak Period rate, nor on the Hanna proposal to increase its peak period service limit. Presumably, however, BPA's customer groups would have some concern about the increased revenue deficiency that would result from Hanna's increase in peak period service at the Offpeak Period rate of 7 mills per kwh.

The PPC opposes, on general principles, "rate guarantees extending beyond the period of the rate case." The PPC claims that the revenue deficiency resulting from such a guarantee for Hanna "would be unfair to BPA's other customers." Wolverton and O'Meara, PPC, E-PP-04R, 9.

Hanna explains that the 7-mills SI-85 Offpeak Period rate will enable the company's Riddle facility to continue to operate in the short run despite the low market price of nickel. Wedge, Hanna, E-HN-01, 6-11; Moke, Hanna, E-HN-02, 5-6. BPA proposed continuing this rate for the 27-month rate period. Peters, BPA, E-BPA-41, 22-23. Hanna explains that the company is [page 247] currently mining "a small deposit of high grade nickel ore"; this circumstance reduces Hanna's costs of production. When the high grade ore is exhausted. however, the Riddle plant may not be able to continue to operate without "major modifications" to increase its efficiency. Wedge, Hanna, E-HN-01, 11-12. The modification Hanna proposes to implement is a wet screening process. The wet screening process will allow more high grade nickel ore to be recovered from lower-grade deposits, and will substantially reduce Hanna's unit production cost. Hanna claims that without modification of its processing equipment, and with the depletion of the high grade ore it is currently mining, the Riddle plant will soon be uneconomic to operate. Wedge, Hanna, E-HN-01, 15-16; Initial Brief, Hanna, B-HN-01, 5. The 5-year contract option under the SI-85 rate would provide Hanna the cost certainty it requires to commit to the estimated $13 million capital improvement for wet screening. All else equal, the capital improvement project should allow the Riddle facility to operate for 5 to 7 years. The wet screening process is uneconomic to implement without a 5-year guarantee of the 7 mill Offpeak Period rate. Wedge, Hanna, E-HN-01, 12-17; Initial Brief, Hanna, B-HN-01, 5. Hanna also explains that the extra 5-6 MW of power the Riddle facility would require during other than its Offpeak Period is necessary to operate the additional equipment used in the wet screening process. Wedge, Hanna, E-HN-01, 13. The benefits to BPA's customers and to the Region arise from the continued production of nickel, a raw material indigenous to the Pacific Northwest (Wedge, Hanna, E-HN-01, 4), and from Hanna's continued purchase of power from BPA during the surplus period. Melton, BPA, E-BPA-56R, 4; Moke, Hanna, E-HN-02, 8-10; Initial Brief, Hanna, B-HN-01, 7-8.

Hanna's operation past the short-term clearly is dependent upon keeping its production costs as low as possible. Peters, BPA, E-BPA-41, 22; Melton, BPA, E-BPA-56R, 4. The operation of Hanna's Riddle facility is beneficial to BPA's system operations in the current power surplus (Melton, BPA, E-BPA-56R, 4), which is expected to last well beyond the next rate period, at least into calendar year 1990. Fuqua, BPA, E-BPA-14S, 1-2.

**Decision**

*BPA is offering Hanna a 5-year contract option under the SI-85 rate, contingent upon Hanna's capital improvement project. The resulting operation of the Hanna Riddle facility will benefit the Region. The benefit will arise from the production of nickel, a raw material indigenous to the Northwest. Also, BPA is granting Hanna's request for an increased peak period service limit of 15 percent of contract demand, also contingent upon Hanna's installation of wet screening equipment.*

## F. Firm Capacity Rate

**Issue #1**

*Should BPA's firm capacity rate include sustained peak surcharges?*

[page 248]

**Summary of Positions**

The sustained peak surcharges account for two types of costs that BPA incurs to provide firm capacity service: the first relates to a reduction in sustained peaking capability due to the extended peak use of the BPA system; the second relates to BPA's periodic inability to accept energy returns without causing forced sales or spill. Schaller, BPA, E-BPA-40, 4-5. The ICP asserts that the addition of a cost-based surcharge to a rate that is not cost-based is inappropriate. In the ICP's opinion, the CF-85 rate is not a cost-based rate because of the equalization of demand. Wilson, ICP, E-IC-07, 2. The ICP also believes that sustained peak surcharges are inconsistent with the existing firm capacity contracts and constitute a unilateral change of the contract. Wilson, ICP, E-IC-07, 2, 4.

**Evaluation of Positions**

The ICP maintains that firm capacity customers pay a surcharge of 22 percent over the cost of providing service because of the equalization of demand mechanism. Wilson, ICP, E-IC-07, 2. This mechanism, which the ICP claims is not cost-based, results in a surcharge that should be considered adequate compensation for any costs incurred due to firm capacity service beyond those already allocated in the COSA. Wilson, ICP, E-IC-07, 3-4. BPA disagrees that equalization of demand has no cost basis. Schaller, BPA, E-BPA-40, 2; E-BPA-61R, 2. Equalization of demand recognizes the similarities in cost and service between the demand requirements for firm capacity and priority firm service. Schaller, BPA, E-BPA-40, 2; BPA, E-BPA-40S, 3. Demand equalization also is cost justified in that it offsets some of the substantial benefit received by firm capacity customers for being treated as if they were part of the 7(b) resource pool, whose costs result in lower rates than costs from the 7(f) pool. For example, even after demand equalization, the annual Firm Capacity rate of $3.62 kW/month is only 61 percent of the demand charge in the Surplus Power rate. If the Firm Capacity rate were treated as part of the 7(f) pool, it would be allocated more expensive exchange costs, and the resulting rate would be similar to the SP-85 demand charge. Finally, demand equalization recognizes the operational costs BPA incurs as a result of having to accept offpeak energy. Schaller, BPA, E-BPA-61R, 2.

The ICP also asserts that firm capacity customers are permitted by contract to take capacity for as long as they schedule it, and to return it at rates up to 100 percent of contract demand. BPA, in the ICP's view, is unilaterally imposing changes of contract conditions on firm capacity

customers by adding surcharges that are inconsistent with the contract language. Wilson, ICP, E-IC-07, 2, 4, 9. However, BPA's surcharges are not inconsistent with the firm capacity contracts. The surcharges are designed to recover the costs of, but not to prohibit, extended peak purchases and excessive rates of energy return. Schaller, BPA, E-BPA-40, 7. BPA, Staff Evaluation of the Record, May 1981, 87. As the ICP admits, the CF rate schedule is part of the ICP's firm capacity contracts, as incorporated by section 5 of these contracts. Wilson, ICP, TR 4723-4724. Section 5 of the contracts states that the purchaser shall pay the Administrator according to
[page 249] the terms of the rate schedule and of the GRSPs. Other than the CF rate schedule itself, the firm contracts contain no provisions stating the terms of payment for the services that the contracting party receives.

The ICP declares it a violation of sound business principles to use ratemaking to impose restrictions to which customers in their contracts did not accede. Initial Brief, ICP, B-IC-01, 43. However, the contracting customers did "accede" to pay for their capacity in accordance with the rates established in the rate schedules. This, too, was part of the negotiating process and has become part of the contract. In addition, it comports with sound business principles for BPA to recover costs in providing firm capacity service.

Finally, the ICP alleges that the application of a surcharge to CF customers is ill-advised given BPA's forecast of capacity surplus, since surcharges will discourage capacity purchases from BPA. Initial Brief, ICP, B-IC-01, 40. However, the ICP overlooks the fact that, prior to the initiation of the surcharges, customers were purchasing capacity under current contracts up to 12-14 hours per day. Dean, BPA, 1981, Ex. T-6, 9. PP&L, 1981 Initial Brief, p. 5. Without the surcharges, BPA would be giving away its surplus capacity to firm capacity customers in an amount equal to the reduction in sustained peak capability caused by their increased demand duration. As the DSIs correctly point out, BPA would be prudent to attempt to sell all of its surplus, not give it away, even if BPA currently assumes that some of it is unsaleable. Peseau, DSI, E-DS-15R, 3.

**Decision**

*The sustained peak surcharges are consistent with the firm capacity contracts. The benefit that the CF customer gains by being treated as if it were part of the 7(b) pool far outweighs any costs that it incurs from demand equalization, which is a result of being so treated. The sustained peak surcharges appropriately recover the costs of extended peak purchases and excessive rates of energy return.*

**Issue #2**

*How should the extended peaking surcharge be calculated?*

**Summary of Positions**

The extended peaking surcharge is added to the purchaser's monthly demand charge for each hour that the purchaser's demand duration exceeds 8 hours. The surcharge measures the cost to

BPA of sustaining generation beyond an 8-hour demand duration in terms of the value of reduced hydro peaking capability. Schaller, BPA, E-BPA-40, 5. The ICP objects to BPA's determination of an 8-hour demand duration, claiming that it is inappropriate to base the demand duration for firm capacity customers on contractual limitations imposed on another customer class, notably the power sales
[page 250] customer. Wilson, ICP, E-IC-07S, 2. The ICP also believes that the surcharge is six times too high because BPA has inappropriately based its surcharge on the single greatest daily demand duration in a given month. Wilson, ICP, E-IC-07, 7-8.

**Evaluation of Positions**

The ICP misstates BPA's reason for its choice of 8 hours as an appropriate demand duration upon which to base a surcharge. The ICP infers from BPA's rebuttal testimony that the 8-hour demand duration is meant to be "consistent with contractual limitations on firm capacity purchases under the power sales contract." Wilson, ICP, E-IC-07S, 2; Reply Brief, ICP, R-IC-01, 15-16. In fact, the ICP removes from its context the first part of a BPA response which concludes, "it is reasonable that a single demand duration be applied equally to all firm capacity customers." Schaller, BPA, E-BPA-40S, 2. The reasonableness of BPA's position appears on the pages of testimony that follow. First, the method used since 1981 is described. Its purpose is to permit capacity purchases without a surcharge in amounts equal to the average number of hours per day that priority firm customers purchase firm power during the peak period. Schaller, BPA, E-BPA-40S, 3. A look at the historical method shows that the average purchases referred to are not peak period purchases in their entirety, but only those peak purchases that exceed the daily average. ICP, Ex. PL-21, TR 3911, 4365. This historical attempt to find an equivalent to a firm capacity purchase is refined and simplified in BPA's initial proposal, but it does not represent a departure from the logic of BPA's previous method. Schaller, BPA, E-BPA-40S, 3.

Second, BPA departs from its historical calculation of demand duration, because the sustained peak surcharges are being extended in this rate case to include firm capacity purchases under the power sales contract. Schaller, BPA, E-BPA-40S, 3. The previous method sought a demand duration by determining an approximation of a capacity purchase by the firm power customer on an historical basis. Under the present circumstances, it is more appropriate to base the demand duration on the maximum firm capacity purchase allowed by contract to the firm power customers. Historically, the firm power customer has not purchased firm capacity. Schaller, BPA, TR 3900-3901; PP&L, Ex. PL-20, TR 4365. However, the firm power customer is permitted capacity purchases by contract for a maximum period of 8 hours per day. Schaller, BPA, E-BPA-40S, 3-4. To set a demand duration based on the maximum firm capacity purchase allowed the PF customer is consistent with BPA's original intent to capture the CF customer's contribution to the loss of system capability relative to public agency sales. BPA, 1981 Rates ROD, IX-22-23.

The ICP claims to have recommended in the 1983 rate proceeding an extension of the demand duration from 9 to 10 hours, based on more recent data. Initial Brief, ICP, B-IC-01, 43. This is mistaken. No "recent" data were placed on the record in 1983, either by BPA or any of the parties. Because of this lack of new data the Administrator used "rate continuity" to justify the continued application of 9 hours. BPA, 1983 Rates ROD, 272.
[page 251]

Regarding the calculation of the extended peaking surcharge, the ICP objects that the surcharge is applied to the single greatest demand duration in a given month. The surcharge is the same under BPA's proposal if a customer exceeds its demand duration by 1 hour during 1 day in a month and if it exceeds the demand duration every day of the month. Wilson, ICP, E-IC-07, 7. However, the extended peaking surcharge is applied in the same manner as any demand billing charge. A customer is billed for its full contract demand no matter how often it purchases that full amount during any month. Schaller, BPA, E-BPA-61R, 3. Under the firm capacity contracts, the billing demand is set equal to the contract demand, and BPA is obligated to be "ready to serve" the purchaser's capacity needs. Schaller, BPA, E-BPA-40, 2. The ICP apparently believes the demand charge to be a function of the rate of delivery. Wilson, ICP, TR 4716-4717. This is incorrect. The "pattern of use" to which the ICP alludes is irrelevant for the purposes of a demand charge. Initial Brief, ICP, B-IC-01, 45.

The ICP's contention that the extended peaking surcharge is six times too high is based on its assumption that this addition to a demand billing charge is somehow energy-related. Wilson, ICP, E-IC-07, 7-8; TR 4384-4385. It is in this context that the ICP concern regarding the cost to BPA of exceeding the demand duration 1 hour per month as opposed to every day of the month must be understood. However, if one considers the demand charge as measuring BPA's readiness to serve, then BPA's calculation is correct and the extended peaking surcharge is not overly high. Schaller, BPA, E-BPA-40, 2; E-BPA-61R, 3.

The ICP states that its calculation of the extended peaking surcharge yields a result similar in amount to the extended peaking surcharge currently in effect. The ICP states that the proposed surcharge is calculated in a somewhat different manner from the current surcharge, and the ICP implies that the increase in the rate is a result of the alleged change in method. Wilson, ICP, E-IC-07, 9. However, the method of calculating the level of the charge has not changed. Rather, the determination of the amount of peak reduction owing to sustained peak use has been refined. Schaller, BPA, E-BPA-40, 6. Specifically, the analysis of sustained peak capability now determines the quantity of peaking capacity available to market on a long-term basis. Fuqua, BPA, E-BPA-14, 15. In addition, the sustained peaking studies assume critical water conditions. PP&L, Ex. PL-18, TR 4364. Critical water was selected because it represents a level of hydro peaking capability that would occur with about a 90-95 percent probability. Fuqua, BPA, E-BPA-14, 17-18. These refinements to the sustained peaking studies account for most of the increase in the extended peaking surcharge. Schaller, BPA, E-BPA-40, 6.

The ICP claims that priority firm customers may cause the same loss of surplus peaking capacity as firm capacity customers and yet are not subject to a surcharge, citing a statement by BPA that metered requirements customers *with extended peak loads* cause a loss of peaking capability. Initial Brief, ICP, B-IC-01, 44; Reply Brief, ICP, R-IC-01, 16. However, BPA repeatedly stressed the fact that metered requirements customers and capacity customers cannot easily be compared. Schaller, BPA, TR 3913, 3914, 391 6, 3918, 4395-4396. Customers that purchase energy off-peak are different from those [page 252] that return energy off-peak. Schaller, BPA, TR 3916. Customers having significant off-peak loads, for example, offer many potential benefits to the BPA system. One of these benefits is an alleviation of minimum generation constraints during off-peak periods. Schaller, BPA, TR 3932-3933. Another is the alleviation of rate of change of forebay and tailwater constraints. To the extent that these constraints are alleviated, sustained peak capability Actually may be increased by off-peak power purchases from a metered requirements customer. The operation of the sustained peak model clearly illustrates this likelihood.

BPA has been careful to point out that a metered requirements customer is not a peaking customer and that energy purchases during peak hours are not necessarily peaking purchases. Schaller, BPA, TR 4396. Metered requirements customers must dedicate all their generating capability, if they have any, to serve their firm load and must purchase from BPA the entire difference between their total load and their total generation. Metered requirements customers do not have the flexibility of computed requirements customers to shape their purchases. Peters, BPA, E~BPA-35, 13. Customers *with extended peak loads* are by definition low load factor customers, having comparatively few purchases off-peak. No evidence in the record suggests that metered requirements customers meet this definition. Computed requirements customers that do meet this definition are indeed restricted to an eight hour demand duration and rate of return surcharge under the PF and NR rate schedules. Schaller, BPA, E-BPA-40S, 4-5.

**Decision**

*BPA's method for developing an 8 hour demand duration applies a logic used since the 1981 rate case to fit new circumstances, while at the same time simplifying its determination. The calculation of the extended peaking surcharge is consistent with the development of a demand charge for a customer with a fixed contract demand.*

**Issue #3**

*Is the calculation of the rate of return surcharge correct?*

**Summary of Positions**

The rate of return surcharge is based on the amount of sustained peaking capability that BPA loses when the rate of energy return increases by 1 percent from that rate of return (60 percent of contract demand) at which BPA's sustained peak capability is at its highest. The rate of return surcharge is seasonally differentiated to reflect seasonal cost differences. Schaller, BPA, E-BPA-40, 8. The rate of return implicitly recognizes, as well, the cost of forced sales and spill due to the violation of BPA's minimum generation constraints. Schaller, BPA, E-BPA-40, 7. The ICP asserts that the surcharge should be applied only during those months when costs are incurred, namely July through October when forced sales are alleged to occur. Wilson, ICP, E-IC-07, 11-12. The ICP also maintains that the rate of return surcharge
[page 253] is calculated incorrectly. Costs are identified as a result of an increase in the rate of energy return from 60 to 80 percent; the surcharge instead should be based on the costs resulting from an increase in the rate of return between 60 percent and 100 percent. Wilson, ICP, E-IC-07, 12-14. PG&E observes that restricting the rate of return to 60 percent will reduce the load factoring value of CF purchases. Kemp, PG&E, E-GA-01, 17.

**Evaluation of Positions**

The ICP maintains that BPA's cost justification for a rate of return surcharge is that high rates of return cause BPA to spill water or make forced sales due to minimum generation constraints. Wilson, ICP, E-IC-07, 10. Since forced sales occur mainly during late summer and fall months, Wilson, ICP, E-IC-07, 11; since BPA cannot verify quantitatively that BPA actually has experienced such instances of forced sales and spill, Wilson, ICP, E-IC-07, 10, and Schaller, BPA, TR 4382; and since BPA cannot demonstrate any confidence in its projected spill data, PP&L, Ex. PL-15, TR 4363; Schaller and Baldrica, BPA, TR 4380; the ICP concludes that the surcharge should be applied only during those months in which increased costs demonstrably occur on BPA's system. Wilson, ICP, E-IC-07, 12. BPA agrees that forced sales and spill occur principally during July through October. Baldrica, BPA, TR 4382. BPA asserts that a lack of historical data on occurrences of forced sales is due to the difficulty of quantifying such data. Schaller, BPA, TR 4383. BPA asserts that reliable data developed since the initial proposal show significant projected amounts of spill during July through October. Baldrica, BPA, TR 4380-4382.

However, the arguments involving the amount of forced sales and spill that BPA can expect miss the point. Forced sales are a function of both the amount of sustained peaking and the rate of energy return. Schaller, BPA, E-BPA-40, 7. The rate of return surcharge recognizes these costs implicitly but does not attempt to quantify them. Schaller, BPA, E-BPA-40, 7-8. The reduction of sustained peaking capability due to high rates of energy return is quantified, however. Schaller, BPA, E-BPA-40, 8.

Both the rate of return and extended peaking surcharges are measured in terms of reduced sustained peak capability a rising from the violation of certain pondage and nonpower constraints on the hydro system. Schaller, BPA, E-BPA-40, 4-5. These constraints include but are not limited to minimum generation constraints, whose violation induces forced sales and spill. Baldrica, BPA, TR 4385-4386; PP&L, Ex. PL-18, TR 4364; Fuqua, BPA, E-BPA-14, 16-17. These operating constraints are individual project’s pond size, installed generating capability, rate of change of forebay, rate of change of tailwater, rate of change of discharge, minimum nonpower streamflow requirements, and other storage and discharge requirements for flood control, irrigation, navigation, and recreation. Fuqua, BPA, E-BPA-14, 16-17. The sustained peak study demonstrates that such constraints operate in one form or another during any month of the year at any rate of energy return, at any sustained peak use of the system, and at various levels of hydro energy. BPA, E-BPA-08A, 72-73; PP&L, Ex. PL-17, TR 4363. The rate of return surcharge and
[page 254] extended peaking surcharge measure the loss of sustained peaking capability due to the violation of any one of these constraints. Sustained peak loss due to operating constraints that would result in forced sales or spill would most likely occur under low or critical water conditions and between July and October. Fuqua, BPA, E-BPA-14, Attachment 7, 4.

The ICP also would calculate the surcharge differently. It would base the rate of return surcharge on the cost resulting from an increase in the rate of return from 60 percent to 100 percent. Wilson, ICP, E-IC-07, 12-15. This change of method would halve the rate of return surcharge during the winter and reduce it slightly for the summer period. The ICP suggests that BPA's calculation will result in an overcollection of revenue if actual rates of return exceed 80 percent. Wilson, ICP, E-IC-07, 13. However, BPA believes the rate of return surcharge will be a disincentive for high rates of return. Schaller, BPA, E-BPA-61R, 3. In addition, the ICP's suggested method for calculating the surcharge would result in an undercollection of BPA's costs unless the rate of energy return actually reached 100 percent. Schaller, BPA, E-BPA-61R, 3; TR 4388.

Finally, PG&E argues that restricting the rate of return to 60 percent will reduce the load factoring value of CF purchases. Kemp, PG&E, E-GA-01, 17. This is correct. PG&E's observation that 40 percent of return energy must either be returned on peak or be subject to a surcharge is erroneous, however, because the number of off-peak hours per week substantially exceeds the number of peak hours. Kemp, PG&E, E-GA-01, 17. PG&E's conclusion that BPA should either reduce the rate of return surcharge or eliminate it is unsupported. Kemp, PG&E, E-GA-01, 17.

**Decision**

*The calculation of the rate of return surcharge remains unchanged. This surcharge does reflect seasonal cost differences. The level of the surcharge is cost-based and appropriate.*

### G. New Resource Firm Power Rate

The New Resource Firm Power rate schedule applies to the IOUs' load growth and new large single loads of BPA's public agency customers. The design of this rate schedule takes account of the fact that no peak period service is forecast during the rate period.

**Issue**

*Is the calculation of the NR-85 rate correct?*

**Summary of Positions**

In its initial proposal, BPA set the NR-85 rate based on allocated surplus firm power costs for both capacity and energy, with the demand charge set at
[page 255] the equalized demand charge. This is because no peak sales are forecasted for the NR-85 rate schedule during the rate period. BPA, E-BPA-08, 63. The ICP objects to this ratesetting method, arguing that the NR-85 is not a cost-based rate and that BPA's proposed rate will recover revenue in excess of allocated costs. Lauckhart, ICP, E-IC-05, 1-4.

**Evaluation of Positions**

In BPA's initial proposal, the NR-85 rate schedule included an equalized demand charge, Although no power is forecasted to be taken during peak hours. The energy charge was calculated based on the SP-85 charge. BPA, E-BPA-08, 63. This is essentially the same method adopted for the NR-83 rate in the 1983 rate case. BPA, 1983 Rates ROD, 278-279. The ICP raises the same objections in the 1985 rate filing that it did in 1983: the New Resources rate is not cost-based and will recover revenue in excess of allocated costs. Lauckhart, ICP, E-IC-05, 1-4; Lauckhart, ICP, WP-83-E-IC-02, 1-4. The ICP proposes that the NR-85 energy rate be based on energy costs allocated to the NR customer and that capacity be charged at the equalized demand rate. Lauckhart, ICP, E-IC-05, 4.

BPA's response to the ICP's objections in the 1983 Administrator's Record of Decision was that a New Resource rate based on an equalized demand charge and an energy charge equal to unit allocated NR energy costs would constitute an average rate lower than the overall cost of resources allocable to that rate class. Normally, the design of a rate with an equalized demand charge requires an increase in the energy charge, because tha [sic] equalized demand charge will not collect total allocated capacity costs. This method does not work for the NR rate because no demand costs are allocated to NR. Therefore, it is proper to calculate a rate with energy charges and equalized demand charges based on exchange and new resource demand and energy costs. Thus, while the rate does not collect the costs allocated to the NR customer, it is based on the cost of the resources available to serve that class. BPA, 1983 Rates ROD, 278-279.

According to the ICP, it is implausible to assume that the proposed NR-85 rate would have resulted from the cost allocation process had both energy and demand loads been forecasted for the class. The level of the NR rate would depend on the forecasted level of NR demand load. Reply Brief, ICP, R-IC-01, 19. However, the development of any rate of general applicability is complicated by the fact that customers have different load factors. BPA's position is that the choice of 100 percent load factor to develop the NR-85 rate is appropriate.

**<u>Decision</u>**

*BPA continues to calculate the NR-85 rate based on costs allocated to surplus firm power, to achieve the goal of a cost-based rate with both demand and energy charges. The Administrator's rationale in 1983 is no less appropriate in the 1985 rate case. However, BPA does not equalize the NR-85 demand charge for the final proposal. The fact that the CF-85 rate schedule*
[page 256] *will no longer be extended to new contracts makes demand equalization unnecessary. The effect of this proposed change on the level of the NR-85 rate is that the demand charge will recover a greater proportion of the total allocated costs, allowing the energy charge to be reduced.*

### H. Surplus Firm Power Rate

The SP-85 rate is available for the purchase of surplus firm power or capacity. SP-85 power is available for purchase within and outside the PNW and the U.S. The SP-85 rate consists of two components: a Resource rate and a Contract rate. The Resource rate is based on the cost of power from specified resources for sales above the fully allocated cost of surplus firm power, and is flexible below that level. The Contract rate is based on the fully allocated cost of surplus resources and also is flexible below that level. For contracts that extend past September 30, 1987, purchasers may opt for a fixed or variable escalation factor.

**<u>Issue #1</u>**

*What costs should be allocated to the SP Contract rate?*

**Summary of Positions**

The SP Contract rate is based primarily on the cost of exchange and new resources. In the initial proposal, conservation costs were allocated to the SP rate to the extent that the rate class is served with new resources. BPA, E-BPA-08, 64-65; BPA, E-BPA-01, 14.

Based largely on the contention that the SP rate should be based on the cost of operating resources that supply the surplus power, various California parties argue that the SP rate should not include the costs of exchange resources, 7(b)(2), 7(c)(2), and the surplus firm power revenue deficiency. Enderby and Mattson, CPUC, E-CP-01, 37-38; Hull, SCE, E-CE-01A, IV-2-7; Reply Brief, SCE, R-CE-01, 32-33; Parmesano and Whitney, LADWP, E-LA-01, 18; Initial Brief, LADWP, B-LA-01, 7; Kemp, PG&E, E-GA-01, 13; Initial Brief, PG&E, B-GA-01, 9-10. PG&E contends that residential exchange, 7(b)(2), and 7(c)(2) costs are costs incurred for *intra*regional subsidies that do not benefit BPA's *extra*regional customers. Initial Brief, PG&E, B-GA-01, 9-10. The ICP argues that the SP Contract rate should include a larger proportion of conservation costs. Kellerman, ICP, E-IC-06, 10-12.

**Evaluation of Positions**

California parties generally have argued that various costs should not be included in the SP rate because the SP rate should be based on the cost of operating resources that supply the surplus power. SCE concludes that it is inappropriate to allocate exchange costs to the SP rate because the exchange
[page 257] is not a real resource that can produce surplus firm power. Hull, SCE, E-CE-01A, IV-2; Initial Brief, SCE, B-CE-01, 44-45; Reply Brief, SCE, R-CE-01, 32-33. CPUC characterizes the exchange as "accounting transfers" that "do not cause the firm surplus." Enderby and Mattson, CPUC, E-CP-01, 36. PG&E contends that the exchange benefits only Northwest customers and does "not contribute to the availability of surplus firm power." Kemp, PG&E, E-GA-01, 13; Initial Brief, PG&E, B-GA-01, 9-10. LADWP characterizes the exchange as a subsidy to certain Pacific Northwest customers. Parmesano and Whitney, LADWP, E-LA-01, 18; Initial Brief, LADWP, B-LA-01, 7.

PGE contends that exchange costs are appropriately included in the SP rate for three reasons. First, the Northwest Power Act clearly regards the exchange as a resource as evidenced by the explicit language describing the terms and conditions of the purchase and sale of power in exchange transactions. PGE argues that sections 5(c)(5) and (6) do not make sense if the exchange is viewed only as an accounting transaction. BPA is required to purchase power from exchanging utilities to fulfill obligations to PNW residential consumers. Kellerman, PGE, E-GE-02R, 2-4. Second, the 7(k) Initial Decision supports allocation of exchange costs to all BPA customers. Kellerman, PGE, E-GE-02R, 2-4. Third, PGE contends that the California parties' logic regarding the allocation of cost to sales causing the cost is flawed. "BPA would be required to charge exchange purchasers exactly the cost of exchange sales which they make to BPA" which "would be contrary to PL 96-501" and "would obviously defeat the entire purpose of the exchange concept." Kellerman, PGE, E-GE-02R, 5-6.

Along with the FBS resource and new resources, the exchange is a resource for ratesetting purposes. See 16 U.S.C. 839e(b)(1) and (f). Exchange resources together with other resources are matched against BPA's loads. Carr, BPA, STR 1040-1042. To the extent that exchange resources and new resources are not needed to serve loads served under sections 7(b), 7(c) and 7(f) of the Act, these resources are available for sale in the surplus firm market. Exchange costs are thus related to the availability of surplus firm power. Furthermore, exchange loads may not equal exchange resources in the longer term if BPA acquires power from a source other than the exchanging utility as allowed by Section 5(c)(5) of the Northwest Power Act. Therefore, the amount of exchange resource is not necessarily equal to the level of exchange load.

PG&E contends that residential exchange, 7(b)(2), and 7(c)(2) costs are incurred for *intra*regional subsidies which do not benefit BPA's *extra*regional customers. PG&E cites the Congressional Record in which members of Congress argued that the Northwest Power Act was meant to solve regional problems, the costs of which were to be borne by the region. Id. at 10. PG&E thus concludes that the legislative history requires that residential exchange costs and costs incurred as a result of sections 7(b)(2) and 7(c)(2) be excluded from BPA's surplus firm rates. Initial Brief, PG&E, B-GA-01, 9-10; Kemp, PG&E, E-GA-01, 13.

Resort to legislative history is unnecessary, as the exchange resource, whatever its costs, is available for sale under the SP-85 rate. There is
[page 258] nothing in the Act which distinguishes between regional and extraregional beneficiaries of the exchange resource. Moreover, as PGE points out, the rationale relied upon in the Miller decision in assigning exchange costs to nonfirm energy rates applies here. The exchange program "does not benefit the regional customers any more than it does the nonregional customers." Thus, exchange costs should be "allocated to all those benefiting from the BPA system." 29 FERC 63,039, 65,095 (1984).

Finally, section 7(g), 16 U.S.C. §938(e)(g), provides that allocation of costs not otherwise allocated shall be equitably allocated to power rates. It should be noted that Judge Miller relied on section 7(g) in assigning exchange costs to nonfirm energy customers, and rejected a similar argument offered by California parties regarding cost allocation between regional and nonregional nonfirm energy customers. *Id*. at 65,094-65,095.

The allocation of the 7(c)(2) delta is the outcome of section 7(c)(2) of the Northwest Power Act, which governs the determination of the IP rate. This amount is not in any sense a subsidy. It can be positive or negative; i.e., it can increase or decrease other rates. The 7(c)(2) delta allocation Actually decreased the SP rate in the initial and supplemental rate proposals.

SCE objects to the allocation of the SP revenue deficiency to the SP rate by stating that BPA has "no justification for requiring the Surplus Firm Contract class to pay the costs associated with BPA's inability to market all its excess resources." Hull, SCE, E-CE-01A, IV-4. PGE responds that "no rate class … bears more responsibility for BPA's inability to market its firm surplus than the customers who have historically chosen to take advantage of BPA's firm surplus through the purchase of lower cost nonfirm power in lieu of the purchase of power under BPA's surplus rate schedules." Kellerman, PGE, E-GE-02R, 7. Again, BPA treats the SP class in the same manner as its other firm power rate classes when allocating the SP revenue deficiency, as well as other costs and rate design adjustments such as 7(c)(2).

The ICP also argues that a greater proportion of conservation cost should be allocated to the SP rate because the principal beneficiaries of the conservation added during a period of surplus are the utilities that purchase surplus firm power. Conservation adds to the amount of available surplus firm power. In addition, marketability should not be a factor in determining allocation methods. Kellerman, ICP, E-IC-06, 10-11. SCE agrees that SP should receive an allocation of conservation costs because it regards conservation cost as a resource cost that may be the responsibility of the SP purchaser. However, conservation cost allocation would preclude the exchange cost allocation since SCE does not consider exchange to be a resource or the responsibility of the SP class. Hull, SCE, E-CE-03R, V-1. BPA has determined that conservation costs will be allocated to all loads including surplus firm power, regardless of the resource pool serving the firm load. See Chapter V, Section C.

[page 259]

**Decision**

*BPA's surplus firm rates, applicable to both BPA's regional and nonregional customers, properly include costs of the residential exchange, the 7(c)(2) rate directive, and the SP revenue deficiency. The Exchange is a resource for ratesetting purposes and is available for sale in the surplus firm market to the extent it is not needed for loads served under sections 7(b), 7(c), and 7(f) of the Act. There is nothing in the Act which distinguishes between regional and extraregional beneficiaries of the exchange resource. Additionally, the 7(k) Initial Decision of the NF-1 and NF-2 rates issued by Judge Miller supports the allocation of exchange resources to extraregional customers. The 7(c)(2) delta is properly allocated to SP: it is the outcome of determining the IP rate in accordance with section 7(c)(2) of the Act, and is not in any sense a subsidy. The SP revenue deficiency is also properly allocated to the SP rate in that the SP class is treated in the same manner when allocating cost and rate design adjustments as other firm power classes.*

**Issue #2**

*How should individual resources be treated in the design and application of the SP rate?*

**Summary of Positions**

The SP Contract rate is based on the average cost of resources not allocated to other BPA rates. The Resource rate is a variable rate based on the cost of one or more thermal resources, exchange resources, and power purchases. BPA, E-BPA-08, 64-65; BPA, E-BPA-01, 14.

California parties contend that the SP rate should be based on the cost of operating resources that supply the surplus power. Enderby and Mattson, CPUC, E-CP-01, 37-38; Hull, SCE, E-CE-01A, IV-2-7; Parmesano and Whitney, LADWP, E-LA-01, 18; Initial Brief, LADWP, B-LA-01, 7; Kemp, PG&E, E-GA-01, 13; Initial Brief, PG&E, B-GA-01, 9-10. SCE argues that the Resource rate should allow rates based on the cost of hydro resources. Hull, SCE, E-CE-01A, IV-9. SCE contends that the Resource rate must be based on costs of resources that are concurrently operating. Reply Brief, SCE, R-CE-01, 33-34. CPUC proposes an SP demand charge based on BPA’s added cost for the service plus a premium. Mattson, CPUC, E-CP-01, 38-39.

**Evaluation of Positions**

CPUC’s recommended SP rate is based on an approach discussed in "Coordination Transactions among Electric Utilities," by W.C. Earley (*Public Utilities Fortnightly,* September 13, 1984). In this approach, the demand charge is based on no more than the average *embedded* capacity cost of the units expected to provide the power. After deriving this unit cost for BPA, CPUC recommends an SP demand rate based on BPA’s *added* cost for the service, [page 260] plus a premium. CPUC states that the added cost for BPA is zero and the premium should be one-half of the average unit cost. Mattson and Enderby, CPUC, E-CP-01, 36-38. There is no justification offered for the choice of one-half the average unit cost as the premium. As there is a contradiction between the Earley method and CPUC’s final recommendation, BPA cannot make a rate adjustment or design a rate based on this testimony.

LADWP recommends a rate that reflects the cost of resources that would not be operated or fully utilized unless SP sales are made. Parmesano and Whitney, LADWP, E-LA-01, 18; Initial Brief, LADWP, B-LA-01, 7. However, LADWP’s recommendation is a concept more aptly applied to a utility with coal- or oil-fired resources. BPA's integrated hydro and nuclear resource base does not have the same operating characteristics as a coal- or oil-fired resource system. BPA's high fixed cost/low variable cost baseload resources are planned to operate at a constant high level and are generally not displaceable.

PG&E’s alternative SP rate calculation is based on its concept of which BPA costs contribute to the availability of surplus firm power, and which costs were incurred for the purpose of serving nonregional SP customers. Kemp, PG&E, E-GA-01, 13-14; Initial Brief, PG&E, B-GA-01, 9-10. SCE's recommended rate is 100 percent of the variable cost and, based on duration of sale, a portion of the fixed cost of surplus on-line generating resources. The upper limit of the rate would be based on FBS costs. Hull, SCE, E-CE-01A, IV-2-7; Initial Brief, SCE, B-CE-01, 50-51.

PGE argues that Industry-wide practices of pricing surplus power on the basis of the cost of resources furnishing the power do not make sense for BPA. Most utilities sell part of a new plant and charge rates based on that marginal unit, not based on the embedded costs of all the utility’s units. PGE states that "BPA is selling system firm surplus power, not unit-specific firm surplus or ‘layoff’ power." Therefore, PGE asserts that the rates recommended by the California utilities are not directly applicable to BPA. If BPA were to adopt the California parties' recommendations, the surplus firm power rate could be based on the fully allocated cost of WNP-2. This cost would be very high and thus the power would not be very marketable. Kellerman, PGE, E-GE-02R, 7-9. PGE is correct that BPA sells *system* firm power at the SP and SE rates. Although the SP Resource rate allows BPA to identify specific resource costs on which to base the price of surplus firm power, it is difficult to identify a specific resource as the source of the power. Further, although basing the Resource rate on the costs of specific resources allows BPA greater flexibility in marketing the surplus firm power, BPA gives first priority to selling power at the average cost Contract rate.

BPA is statutorily directed to establish all of its rates using sound business principles. Revenues from the sale of surplus firm power must contribute to meeting BPA's obligation to repay the U.S. Treasury and recover total system costs. Therefore, the SP rate recovers the costs of resources not allocated to BPA's other rates. If BPA were to recover less than this remaining cost, its rates would not be set at a level sufficient to recover
[page 261] total system costs. California parties' arguments regarding which resources and costs "really" serve a load are not useful because they do not lead to the formulation of standards appropriate to establishing surplus firm power rates. BPA, 1983 Rates ROD, 280-282.

SCE argues that the Resource rate should include hydro resources because "surplus firm power is made available as a result of all of BPA's resources being in excess of all of BPA's firm system loads." Hull, SCE, E-CE-01A, IV-9. The SP Resource rate is designed to increase BPA's ability to market surplus firm power, but must take into account BPA's other marketing objectives. Some hydro costs may be lower than the NF-85 rate. Thus, using hydro costs for the basis of the SP Resource rate could result in selling surplus firm power at rates well below its average cost, while displacing sales at the NF rate. BPA's surplus marketing effort could be undermined by this effect.

In reply to the draft decision in the Evaluation of the Record (p. 2011, SCE argues that only concurrently operating resources should be the basis for the Resource rate. If this is not the case, the rate is not cost-based and therefore inappropriate. Reply Brief, SCE, R-CE-01, 33-34. BPA plans to continue the same method for selling surplus firm power at the Resource rate as specified for the initial proposal. Sales at the Resource rate will not depend on concurrent operation of the resource being sold. BPA will sell up to the total planned annual output of any resource. Federal system resources will be used to store, shape, and back up these resources to the extent necessary to make the sales. Carr, BPA, E-BPA-39, 14. This policy allows BPA to make long term sales; if BPA depended on concurrently operating resources only, the same quality of service could not be maintained. In addition, relying on concurrently operating resources does not allow BPA to use the hydro/thermal system most effectively. Energy from nonhydro resources can be stored in the hydro system, and operation or purchase of such resources will affect hydro system rule curves. Thus, nonhydro resources can be sold even if not concurrently running.

California arguments that BPA should allocate to the SP-85 rate only the costs of hydro resources or concurrently operating resources are similar to misplaced arguments they have made in the past concerning the costs attributable to nonfirm energy. These arguments have been rejected by BPA in the past and were also rejected by Judge Miller, on the grounds argued by BPA: "BPA 'may operate resources other than hydro and make relatively expensive purchases during the fall and early winter … [w]hen that action turns out to have created the opportunity to sell more nonfirm energy… it is fair to charge the purchasers the cost of the energy. Therefore, the position of the California Utilities is not sound." 29 FERC ¶63,039, 65,097. The Judge found the testimony of the BPA witness credible and persuasive: "At any given instant, whatever water is present in reservoirs is there in part due to the operation and planning of a thermal resource which allowed the water to be stored or to be shifted in time." *Id*. The Judge's

reasoning, which recognizes the integrated nature of the BPA hydro thermal system, applies to the production of surplus firm power as well as to the production of nonfirm energy.
[page 262]

**Decision**

*The pricing of surplus firm power contained in BPA's proposal is appropriate. BPA allocates costs to the SP rate in accordance with cost of service principles and Northwest Power Act rate directives. The SP rate is allocated the cost of resources not allocated to other firm classes of service that are surplus to BPA's firm power obligations. However, in order more effectively to market surplus firm power, the SP Resource rate allows BPA to price the power based on the cost of planned resources. Concurrent operation of such resources is not required due to the storage capabilities of the hydro/thermal system.*

**Issue #3**

*Is the fixed escalation factor in the SP and SE rates appropriate?*

**Summary of Positions**

The SP Contract rate allows for sales of a longer term than the 27-month rate period. Carr, BPA, STR 1035. For sales that terminate after September 30, 1987, two escalation factors are provided. The variable escalation factor is based on the annual rate of increase in the cost of IOU exchange resources. BPA, E-BPA-08, 228-229. A fixed annual escalation factor equals the expected average annual increase in the SP rate for the Fiscal Years 1986 through 1991 plus a 2.5 percent uncertainty factor. The forecasted average annual rate of increase is obtained from the Supply Pricing Model; the 2.5 percent factor is based on BPA's judgment of the market and the risks associated with such sales. Carr, BPA, E-BPA-39, 8, 11.

The ICP objects to a rate guarantee beyond the rate period and contends that it violates the intent of regional preference. In addition, the ICP argues that the 2.5 percent uncertainty factor in the SP and SE rates is too low and should be probabilistically quantified. Kellerman, ICP, E-IC-06, 2-6, 12-13; Reply Brief, PGE, R-GE-01, 5-7.

SCE contends that the 2.5 percent risk factor is unjustified, will ensure a cost overrecovery, and is not consistent with the statutory directive that BPA's rates be the "lowest possible." Hull, SCE, E-CE-03R, V-1-2; Initial Brief, SCE, B-CE-01, 45-46; Reply Brief, SCE, R-CE-01, 33. CPUC recommends that SP and SE be offered for the projected duration of the surplus and that the escalation factor should be based on the projected cost escalation of surplus resources. Enderby and Mattson, CPUC, E-CP-01, 39, 42.

**Evaluation of Positions**

The ICP objects to a rate guarantee beyond the rate period through election of the fixed escalation factor. First, the ICP argues that a guarantee places significant risk on BPA's PNW customers since they will shoulder the burden of revenue underrecovery should loads be lower and costs [page 263] higher than forecast. Kellerman, ICP, E-IC-06, 5. However, BPA and its PNW customers are being compensated for that risk by adding the uncertainty premium to the fixed escalation factor. Second, the ICP argues that rate predictability is at least as important for the PNW as it is for the PSW. Kellerman, ICP, E-IC-06, 3-4. BPA recognizes that rate predictability is important for all its customers. Currently, BPA has a separate public involvement process underway to analyze the option of long-term rate guarantees for the DSIs. Hanna is also being offered a 5-year rate guarantee (*see* Section E). Carr, BPA, STR 1031-1032. The SP and SE rates are available to PNW as well as PSW customers. The marketability of surplus firm power is dependent on many factors that either are not in BPA's control or have not yet been determined. Rate dependability is a valuable factor in increasing marketability. Kellerman, ICP, E-IC-06, 4. In fact, election of the fixed escalation factor by a purchaser could result in a higher rate than that determined in future rate filings. Carr, BPA, E-BPA-55R, 2.

In addition, a revenue underrecovery from the failure to sell surplus firm power drives up PNW rates. Thus, while there is some possibility of an underrecovery from a long-term sale, it would enhance revenues over the current situation in which BPA is selling a portion of its surplus firm power at rates lower than fully allocated cost. The fixed escalation factor is a factor in BPA's forecast of SP sales. "It would be my judgment that the number [BPA's forecast of SP sales at full cost] would be less if the guarantee wasn't there." Carr, BPA, STR 1034-1035.

The ICP and PGE argue that the 5-year rate guarantee violates the intent of regional preference in that this provision allows BPA to offer power to the PSW on more favorable terms than it offers to the PNW. SP rate "sales will be made subject to the 5-year rate guarantee only to the Pacific Southwest." Reply Brief, PGE, R-GE-01, 6. These parties argue that PNW customers do not receive similar benefits for rates generally applied to PNW sales. Kellerman, ICP, E-IC-06, 2-4.

The ICP and PGE surely are aware that BPA offers all available surplus firm power to the PNW before making it available outside the region. Surplus firm power sales with a 5-year rate guarantee offered to PSW customers will always be offered first to PNW utilities with the same guarantee. In fact, establishment of the intertie adder facilitates SP sales to PNW customers because they no longer pay intertie costs. BPA offers long-term availability of surplus firm power before it resorts to shorter term offers. Carr, BPA, E-BPA-39, 12-15.

The fact that PNW customers do not receive long-term guarantees for rates offered only in the PNW is immaterial to the question of whether regional preference has been satisfied. Regional preference is applicable only to rates for sales outside the PNW.

The ICP asserts that the uncertainty factor of 2.5 percent in the SP and SE rates is too low. "Actual uncertainty of the type described by BPA witnesses must be compensated by a relatively high premium if BPA's utility
[page 264] function is characterized, as it should be, by a risk averse rather than a risk seeking preference." Kellerman, ICP, E-IC-06, 12-13; Reply Brief, PGE, R-GE-01, 6-7. ICP and PGE propose, with no support, a figure in the range of 6 to 8 percent. Kellerman, ICP, STR 1272.

SCE argues that the premium is unjustified since it would ensure a cost overrecovery if BPA's projections of SP costs are correct. In addition, neither BPA nor the ICP has performed studies to determine a proper risk premium. Hull, SCE, E-CE-03R, V-1-2; Initial, Brief, SCE, B-CE-01, 45-46.

The SP fixed escalation factor reflects BPA's forecast of SP cost plus the 2.5 percent uncertainty factor. Although the uncertainty associated with future loads and costs is inherently unmeasurable, a reasonable premium for uncertainty is necessary. "The 2.5 percent figure is not unreasonably high, provides predictability for BPA's customers, and provides some compensation to BPA for the risk associated with a long-term sale." Carr, BPA, E-BPA-39, 5. A higher premium could increase the risk of being unable to consummate sales of surplus firm power. Carr, BPA, E-BPA-55R, 4. By fixing an escalation factor to promote sales of SP and adding a premium to reduce BPA's risk of revenue under-recovery, BPA is acting in a risk-averse manner. SCE is correct that BPA would overrecover revenue if its forecast of SP costs occurs, all else equal. However, the cost of the risk involved in fixing the SP rate must also be compensated; the 2.5 percent premium is designed to provide such compensation. Carr, BPA, STR 1036. In addition, a customer can opt for the variable escalation factor based on the actual increase of resource costs if the 2.5 percent premium is considered too high.

PGE suggests a premium equal to one or two standard deviations. PGE argues that the 2.5 percent escalation rate is "far less than recent Bonneville rate increases" and that "it fails to compensate Bonneville for the risk that its cost increases in the next 5 years may greatly exceed 2.5 percent." Reply Brief, PGE, R-GE-01, 6-7; Kellerman, ICP, E-IC-06, 13. The fact that 2.5 percent is far less than recent BPA rate increases is irrelevant. The 2.5 percent is added to BPA's projected SP rate increase to calculate the fixed SP escalation factor. Thus, BPA would be compensated for the projected SP rate increase *plus* the risk of guaranteeing the rate. BPA is compensated for the risk of SP rate increases being greater than it projects; the SP purchaser accepts the risk that the SP rate increase will be less than projected. In addition, BPA's rate increases are expected to be small; e.g., the revenue requirement increase is less than 3 percent from FY 1986 to FY 1987. ICP's and PGE's suggested analysis would be cumbersome without necessarily providing any greater assurance than is available from the proposed 2.5 percent premium. The ICP has proposed neither a specific method, nor the results from applying any method. Carr, BPA, E-BPA-55R, 4.

Finally, SCE's argument that the escalation factor violates the lowest possible rates standard is misplaced. As BPA has discussed in prior Records of Decision, the lowest possible rates standard applies to all of BPA's rates taken together, and does not apply to individual rate schedules in isolation. Application of such a standard to any rate in isolation logically leads to the
[page 265] absurd result that the particular rate could be driven to a nominal level, and other rates would be forced to rise above the "lowest possible" level in order to assure that BPA meet its revenue requirement. Rather, rates overall must be designed to recover no more than BPA's total revenue requirement.

**Decision**

*The fixed escalation factor is appropriate; it will increase the marketability of the surplus firm power. The uncertainty factor compensates BPA for the risk that costs will be higher or loads lower than forecast.*

**<u>Issue #4</u>**

*To what extent should the SP rate be flexible?*

**<u>Summary of Positions</u>**

The proposed SP Contract rate is a fixed rate based on the fully allocated cost of service. The flexible Resource rate is based on BPA's assessment of current market conditions and the cost of BPA's planned resources. The Resource rate may be higher or lower than the Contract rate and may only be applied to sales of less than 1 year. Carr, BPA, E-BPA-39, 12-14.

LADWP and the ICP recommend that the SP rate be flexible in both directions. Parmesano and Whitney, LADWP, E-LA-01, 18, and STR 1184-1185; Initial Brief, LADWP, B-LA-01, 7; Kellerman, ICP, STR 1272-1274. PG&E argues that the average cost of surplus firm power should be considered a ceiling from which BPA could adjust the rate downward in order to be competitive. Kemp, PG&E, E-GA-01, 14-15, 18. SCE also argues that the Contract rate should be the upper limit and that there should be no floor. The demand charges should be flexible downward to reflect the duration of the SP sale. Hull, SCE, E-CE-01A, IV-55; initial Brief, SCE, B-CE-01, 51. The CEC agrees with the positions of PG&E and SCE regarding the construction of the SP rate. Reply Brief, CEC, B-CC-02, 24-25.

CPUC argues that the Resource rate is too broad since it provides the flexibility to charge rates over a wide range and the rate charged is unverifiable. Enderby and Mattson, CPUC, E-CP-01, 35-36.

**<u>Evaluation of Positions</u>**

With the exception of CPUC, the parties endorse the concept of flexibility in the SP rate. LADWP argues that SP flexibility should be in both directions in order "to structure different types of sales to meet the needs of particular customers" in terms of delivery, length of sale, and capacity and/or energy. This would allow BPA to reflect the costs of specific resources being used. Parmesano and Whitney, LADWP, STR 1184-1185; E-LA-01, 18; Initial Brief, LADWP, B-LA-01, 7. The ICP agrees that the SP rate should be flexible in both directions. Kellerman, ICP, STR 1272-1274.

[page 266]

PG&E and SCE contend that the SP rate should have downward flexibility only. PG&E argues that downward pricing flexibility is required for BPA to avoid being undercut or priced out of a changing market, citing "the rapidly evolving resource mix within California and the price volatility of competing primary energy sources." Kemp, PG&E, E-GA-01, 15. SCE argues that the Contract rate should reflect the full cost of surplus firm power, but should be reduced for sales of duration less than a year to reflect "the more limited commitment of BPA's generating capacity." Initial Brief, SCE, B-CE-01, 51; Hull, SCE, E-CE-01A, IV-5. PG&E and SCE also object to the "floor" in the SP rate. Initial Brief, SCE, B-CE-01, 47; Initial Brief, PG&E, B-GA-

01, 10-11. BPA indicated that SP Resource rate sales would probably not be made at rates lower than the NF Standard rate plus 2 mills per kilowatt hour. Carr, BPA, TR 1043, 1066.

The flexibility of the SP Resource rate allows BPA to respond to changing market conditions and thus sell more surplus firm power than might otherwise be possible at a fixed rate. It also allows BPA the opportunity to collect, on average, the full cost of surplus firm power by charging rates greater and less than the Contract rate. If BPA were allowed only downward flexibility, BPA would be assured of undercollecting the cost of surplus firm power if even one sale of surplus firm power were made at less than the Contract rate. Kemp, PG&E, STR 1178-1179.

PGE argues that downward-only flexibility "may encourage potential purchasers to wait for conditions which would enable them to possess a better bargaining position before entering into negotiations." In addition, the differential between the SP Contract rate and the NF Standard rate is not large, so that downward-only flexibility would not substantially improve BPA's marketing flexibility. Kellerrnan, PGE, E-GE-02R, 10-11.

The ICP and LADWP are correct that rate flexibility in both directions is important to enhancing SP marketability. PG&E’s arguments that the SP rate needs to have downward-only flexibility in order to adapt to a changing market may be valid, but there is no reason to limit BPA to a situation in which it can only underrecover revenue. If sales were made at a rate above the Contract rate, BPA could collect revenue closer to its average surplus firm power cost instead of chronically collecting a lower average revenue. The initially proposed SP rate restricts sales at rates above the average surplus firm power cost to periods less than 1 year.

**Decision**

*Additional flexibility in the SP rate will increase the marketability of surplus firm power by enabling BPA to tailor sales to purchasers' needs. The final proposed SP rate is altered to introduce this flexibility. The SP Resource rate is expanded to allow BPA to sell unit-specific power at cost for periods longer than 1 year. Both the fixed and variable escalation factors will be available for these sales. Thus, if BPA charges a rate higher than the Contract rate, the rate will be based on the cost of specific resources. The Contract rate will allow downward-only flexibility to enable BPA to*
[page 267] *respond to market conditions such as those described by PG&E. This flexibility will include changes in the individual rate components.*

*With these changes to the SP rate, BPA will have the ability to market surplus firm power at a rate higher than the cost-based Contract rate when it is selling unit-specific power, and will have the flexibility to charge a rate lower than the cost-based Contract rate to respond to long-term market conditions. BPA will continue to give first priority to selling surplus firm power at the cost-based Contract rate. In addition, when making sales at the Resource rate below the cost-based Contract rate, BPA will not need to link the price of the sale to specific resources. Since these sales are made at prices below cost, BPA’s main interest is to ensure maximum flexibility in responding to market conditions.*

**Issue #5**

*Is the SP rate discriminatory?*

**Summary of Positions**

The SP rate allows BPA to charge more than one rate at a time based on different resource costs in order to respond to market conditions. Carr, BPA, E-BPA-39, 13-14.

CPUC argues that this ability to charge more than one rate at a time gives BPA an opportunity to unfairly price discriminate between customers and regions. In addition, CPUC argues that the SP rate should not be offered in the PNW. Enderby and Mattson, CPUC, E-CP-01, 34-36. SCE contends that undue discrimination against nonregional customers may result if implementation criteria are not defined for the SP, SE, and NF rates. Hull, SCE, E-CE-01A, IV-11-12; Initial Brief, SCE, B-CE-01, 51.

**Evaluation of Positions**

CPUC contends that BPA has an opportunity to unfairly price discriminate between regions and customers, given the ability to charge more than one SP rate at a time. CPUC also complains that price differences are unverifiable and argues that the SP rate should not be offered in the PNW. CPUC asserts that since PNW utilities can already buy all required power at other rates, the only reason to allow them to purchase at the SP rate would be "in connection with essentially giving BPA unlimited ability to set prices as it wishes … or with charging more than one rate at a time." Enderby and Mattson, CPUC, E-CP-01, 34-36.

BPA's objective in marketing surplus firm power is to recover its full average cost of the power. The ability to market surplus at different rates enhances BPA's ability to realize its objective of full cost recovery. Carr, BPA, E-BPA-39, 13-14. Flexibility that allows cost recovery is consistent with sound business principles. In addition, setting different prices for [page 268] different customers can reflect different resource costs as well as varying sale conditions. Parmesano and Whitney, LADWP, STR 1185; Carr, BPA, E-BPA-39, 13. BPA gives notice of the amount and price of the available surplus firm power and will verify the numbers if requested. No party actually purchasing BPA surplus firm power at the current SP Resource rate has complained of the prices being unverifiable. Finally, BPA forecasts that there will not be an SP market in the PNW; all SP sales are projected to be made to the PSW. Thus, BPA assumes there will be little opportunity for price discrimination between PNW and PSW customers.

In regard to offering the SP rate only in the PSW, PGE argues that Pub. L. 88-552 requires that such power must be offered in the PNW before it is offered outside the region. In addition, selling SP within and outside of the region avoids "a situation where either region is attempting to unduly raise or lower the cost of any one BPA rate schedule." Kellerman, PGE, E-GE-02R, 9-10. BPA agrees that it is required by the Northwest Preference Act, Pub. L. 88-552, to offer surplus firm power to the PNW before it can be offered to the PSW. Thus, to offer surplus firm power only to the PSW would contravene BPA's express statutory directives.

SCE contends that BPA should define implementation criteria for SP, SE, and NF. Without such criteria, SCE argues that BPA can apply these rates "with unfettered discretion" which "may result in undue discrimination to nonregional customers." Hull, SCE, E-CE-01A, IV-12-13.

Implementation criteria for SP-85 have been provided. BPA will give notice of the amount of surplus firm power available for sale during that operating year. Priority will be given to sales for periods of 1 year or longer. If BPA is unable to market all available surplus firm power on a long-term basis, it will market the remaining amounts of power at the Contract or Resource rate. BPA will generally market such power in weekly blocks at a rate based on BPA's assessment of the market and its planned resources. BPA will give notice of the price and amount of surplus firm power to be offered during the week. Sales may be made for periods of less than a week. Carr, BPA, E-BPA-39, 12-14. In regard to CEC's concern about the relation of the price and duration of sale (Reply Brief, CEC, B-CC-02, 35). BPA makes every effort to market the surplus firm power on a long term basis before offering it for shorter periods such as a month, week, or day.

In addition, there are significant differences between surplus firm power and nonfirm energy. Surplus firm power is subject to far less interruption than nonfirm energy. Surplus firm power is available on a firm planning basis, whereas the amount of available nonfirm energy at a given time is dependent on current year operating conditions. Surplus firm energy can be purchased for relatively long periods of time (weekly, monthly, yearly, or longer), whereas guaranteed nonfirm energy is typically only available for up to 4-day periods. BPA may also be able to shape firm power to a greater degree than nonfirm energy. Carr, BPA, STR 1043-1046, 1056. Surplus firm power that is sold on a short-term basis may look similar to nonfirm energy to purchasers, but it is not similar to BPA. Even on a short-term basis, BPA [page 269] distinguishes between energy that is available on a firm planning basis and nonfirm energy. BPA never sells more surplus firm power than is available; i.e., nonfirm energy is never sold at the SP rate.

BPA recognizes that an inability to sell surplus firm power at its cost may result in the sales of the power at the nonfirm energy rate. BPA, in fact, forecasts this to occur with the 25 percent of the surplus firm power not sold at full cost. In addition, BPA assumes that surplus firm power will not be sold at the SP rate during the month of May since the abundance of power during this month results in the inability to sell surplus firm power at a rate higher than the nonfirm energy rate. Revitch, BPA, E-BPA-27, 4. Northwest parties assert that Southwest utilities have avoided purchase of higher cost surplus firm power with the knowledge that BPA will eventually offer large amounts of nonfirm energy. Kellerman, PGE, E-GE-02R, 7; Opatrny and Cook, Northwest Parties, E-NF-02, 9-10. The PSW parties benefit from BPA's ability to sell firm power at the nonfirm energy rate.

**Decision**

*The SP rate is not discriminatory. Flexibility that allows the setting of different prices reflecting different resource costs and varying market and sale conditions is consistent with sound business* *principles. The SP rate will always be based on resource costs when the offered rate is higher than the average cost of surplus firm power. BPA has retained greater flexibility in setting rates below this level to enhance its ability to recover costs. BPA has provided implementation criteria for the SP-85 rate and has enumerated the differences between surplus firm power and nonfirm energy. Contrary to CPUC's argument, BPA is statutorily required to offer surplus firm power in the PNW as well as the PSW.*

**<u>Issue #6</u>**

*Should the SP Contract rate be seasonally differentiated?*

**<u>Summary of Positions</u>**

The SP Contract rate energy and demand charges are not seasonally differentiated. BPA, E-BPA-08, 222.

SCE recommends that BPA reflect seasonal cost differentials in the SP Contract rate. Hull, SCE, E-CE-03R, V-2.

**<u>Evaluation of Positions and Decision</u>**

SCE asserts that BPA has shown that its costs vary by season and, thus, the Contract rate should reflect seasonal differentials in order to be based on cost of service ratemaking principles. Hull, SCE, E-CE-03R, V-2. BPA does not reflect seasonal differentials in the SP Contract rate for two reasons.
[page 270] First, price signals developed for the PNW may not be appropriate for the PSW because of different load patterns and underlying costs. The pattern of seasonal loads is quite different in the PNW and PSW, so that an analysis of seasonal loads in the PSW would be necessary to develop efficient seasonally differentiated rates. BPA lacks sufficient data for such a study.

Second, seasonal differentiation would likely interfere with marketing surplus firm power to the PSW. BPA forecasts that all SP power will be sold to the PSW; however, BPA rates are highest in the winter when PSW demand is the lowest. BPA considers revenue recovery an important goal for SP marketing. Therefore, seasonal differentials are not reflected in the SP Contract rate.

### I. Nonfirm Energy Rates

### 1. General Form of Rate: Cost-Based or Share-the-Savings

**<u>Issue #1</u>**

*Should BPA have a cost-based nonfirm energy rate, a Share-the-Savings nonfirm energy rate, or both?*

**Summary of Positions**

BPA proposes both cost-based and Share-the-Savings rate schedules. Metcalf, BPA, E-BPA-37, 4-14; E-BPA-64R, 23-26. The NF-85 Standard rate is based on the average cost of service from FBS, new resources, and exchange resources. Other NF-85 rates are set below the Standard rate. BPA also proposes to market nonfirm energy under an experimental rate schedule, the SS-85 Share-the-Savings Energy rate. BPA, Evaluation of the Record, A-01, 172-177.

The Northwest Parties and PGP both contend that BPA can and should adopt a Share-the-Savings rate for the NF-85 rate schedule. Opatrny and Cook, NWP, E-NF-02, 3; E-NF-04R, 2; Reply Brief, NWP, R-NF-01, 1; Garman, PGP, E-PG-02, 3. The ICP believes that BPA may properly offer a Share-the-Savings rate, but the rate component should be implemented such that regional preference to nonfirm energy is preserved. Wilson, ICP, E-IC-14, 3; Reply Brief, ICP, R-IC-02, 1-6.

The Northwest Gas Utilities recommend both cost-based and Share-the-Savings rate components. Reply Brief, NGU, R-WG-01, 12-13.

All California parties object to a Share-the-Savings rate. The parties' objections follow two basic arguments. First, Share-the-Savings rates are inappropriate for BPA because BPA should not base rates on value. Hull, SCE, E-CE-04SR, 4; Reply Brief, SCE, R-CE-01, 40-47; Parmesano and Whitney, LADWP, E-LA-01, 17. CPUC contends that "basing rates on benefits received is not
[page 271] justified in a regulated market" where buyers are not protected by competition. Enderby and Mattson, CPUC, E-CP-01, 10. Nonfirm energy rates must be based on cost, and a Share-the-Savings rate exceeds BPA's costs of production and is therefore inappropriate. Enderby and Mattson, CPUC, E-CP-02R, 8; Kemp, PG&E, E-GA-03SR, 5. Second, share-the-savings rates are not the industry norm for one-way transactions. Kemp, PG&E, E-GA-03SR, 4.

**Evaluation of Positions**

The Northwest Parties argue that share-the-savings rates in general are flexible, equitable, make lower rates available to buyers and sellers, and encourage efficient use of resources. Opatrny and Cook, NWP, E-NF-02, 2; E-NF-04R, 29-30. APAC concurs with NWP and additionally claims that share-the-savings rates encourage PNW and PSW transactions. Cook, APAC, E-PA-01, 7.

The California parties are not correct that BPA may not base nonfirm energy rates on value (benefits), or that share-the-savings rates are accepted only for nonfirm energy transactions that are two-way; that is, where parties to the transaction frequently are buyers and sellers. Share-the-savings methods are commonly used by California utilities to determine transaction prices for their own purchases and sales of economy energy. Metcalf, BPA, E-BPA-64R, 30. Share-the-savings rates "are the standard industry practice in marketing economy energy, and are used by Federal power marketing agencies." Opatrny and Cook, NWP, E-NF-02, 1. Recently, the Commission endorsed share-the-savings principles in approving a New Mexico bulk-power marketing experiment. Id., 2. A study related to this marketing experiment notes that share-the-savings rates are standard industry practice. Hull, SCE, E-CE-03RA, F-31. This study also provides evidence that share-the-savings transactions can be almost exclusively one-way. Id., F-32. Finally, California parties' assertions that BPA's nonfirm energy rates must be based on cost is inconsistent with the 7(k) Initial Decision. 29 FERC at 65,078. See Section 2, below.

BPA is hesitant to base nonfirm energy rates solely on share-the-savings components as recommended by NWP. Implementation of a Share-the-Savings rate is extremely complex and BPA had considerable implementation problems with the H-6 Share-the-Savings rate. Griffin, BPA, E-BPA-65R, 3. A Share-the-Savings rate needs the cooperation of the buyer in order to define and acquire necessary decremental cost information. In addition, the problem of how to compete with alternative purchases has not been solved. See Section 4. As the ICP points out, implementation of a Share-the-Savings rate is also complicated by the need to comply with regional and public agency preference. Reply Brief, ICP, R-IC-02, 1-6.

**Decision**

*BPA is proposing both a cost-based rate with fixed components (NF-85) and an experimental Share-the-Savings rate (SS-85). NWP has presented compelling evidence that a properly constructed and implemented Share-the-Savings rate*
[page 272] *could promote economic efficiency and an equitable sharing of benefits. Nevertheless, there remain a number of difficulties with implementing a Share-the-Savings rate. BPA will attempt to resolve those difficulties through contract negotiation with prospective purchasers. Any problems regarding implementation may be required to be resolved through a section 7(i) hearing pursuant to the Northwest Power Act. See Legal Considerations, Section 2, below. In any event, the implementation of the nonfirm energy rate schedules will be consistent with regional and public agency preference.*

**Issue #2**

*Should the Variable Displacement rate be eliminated from the NF-85 rate schedule?*

**Summary of Positions**

BPA initially proposed the NF-85 Variable Displacement rate to be offered at rates below the Standard rate when the market is satisfied at the Standard rate. The Variable Displacement rate was proposed in part to give BPA experience in marketing nonfirm energy under share-the-savings rates. BPA, E-BPA-08, 69; Metcalf, BPA, E-BPA-37, 8. The Variable Displacement rate applies to displacement of: (1) resources; (2) confirmed purchase alternatives; (3) end-user alternate fuel sources; and (4) resources that may be displaced indirectly. Metcalf, BPA, E-BPA-64R, A13, 5. The rate is calculated as the greater of 75 percent of the purchaser's decremental cost or 11.0 mills per kilowatt-hour. BPA, E-BPA-08, 69; Metcalf, BPA, E-BPA-37, 8-10.

In subsequent testimony, BPA retained the Variable Displacement rate and added the NF-85 High Cost Displacement rate as a complement to the Variable Displacement rate. Metcalf, BPA, E-BPA-64R, 26-27. The High Cost Displacement rate is based on share-the-savings principles but the rate is fixed. The High Cost Displacement rate would, like the Variable Displacement rate, operate below the Standard rate. Displacement of resources or purchase alternatives may or may not be required depending on market conditions. A purchaser is required to execute a contract to receive Variable Displacement rate service, otherwise the High Cost Displacement rate applies. Griffin, BPA, E-BPA-65R, 2. Implementation of the two rates is based largely on determinations of expected revenue under the alternative rates. *Id*., 3.

The NWP argues that BPA should not offer nonfirm energy at either the Variable or the High Cost Displacement rates before clearly establishing the criteria under which BPA will: (1) move from the Standard rate to either of the rates; and (2) determine which of the two rates to offer after the decision to move from the Standard rate has been made. Reply Brief, NWP, R-NF-01, 24. They further argue that implementation of these rates should be based "on the decremental cost of a purchasing utility's resources." *Id*., 25

[page 273]

**Evaluation of Positions**

BPA's proposal to offer the High Cost Displacement rate was based on implementation uncertainties inherent in the Variable Displacement rate. Metcalf, BPA, E-BPA-64R, 26. Rates based on share-the-savings concepts are extremely complex to administer and BPA recognized in its earliest proposals that problems in implementation were possible. Griffin, BPA, E-BPA-38, 6-7. In fact, BPA initially proposed the Variable Displacement rate reserving the right not to offer service at this rate if BPA were unable to determine that the use of such energy met the criteria in the rate schedule. *Id*., 6. The High Cost Displacement rate was proposed as a "backup mechanism" in case the Variable Displacement rate proved in efficient to administer. *Id*., E-BPA-65R, 3. This concern with implementing the Variable Displacement rate, indeed with share-the-savings rates generally, is expressed by BPA's reluctance to adopt nonfirm energy rates based solely on share-the-savings components. Evaluation of the Record, BPA, A-01, 155. There are numerous implementation problems. One such problem is the possibility that the High Cost Displacement rate might be available to some purchasers at 14.0 mills per kilowatt-hour while Variable Displacement rate purchasers having resources with comparable decremental costs are paying a higher calculated rate. In other cases, lower cost resources may be displaced by High Cost Displacement rate sales ahead of higher cost resources eligible for Variable Displacement rate service.

BPA's implementation concerns are echoed by NWP. NWP does not argue that either of these rates should be eliminated (if BPA retains its basic proposal rather than adopting the NWP proposal). Rather, they argue for clearly established implementation criteria. As a basis for such criteria, they contend that these rates should be implemented based on purchasers' decremental costs. This procedure was initially proposed as an alternative by BPA, but was not selected because it would be difficult to administer. Metcalf, BPA, E-BPA-37, 11. Additionally, it is not clear whether implementation in this manner would be consistent with regional and public preference. Reply Brief, ICP, R-IC-02, 1-4.

**Decision**

*The Variable Displacement rate is eliminated from the NF-85 rate schedule. The High Cost Displacement rate is retained as a market expansion rate alternative to the Standard rate. The Variable Displacement rate essentially is duplicated by the SS-85 Displacement rate. The SS-85* *rate satisfies BPA's objective, providing an opportunity to gain experience in marketing nonfirm energy at share-the-savings rates. In addition, BPA has been unable to resolve anticipated problems related to implementing the Variable Displacement rate in conjunction with the High Cost Displacement rate. Retention of this rate in addition to the proposed SS-85 rate would add undue complexity to the nonfirm energy rates without the reasonable assurance of compensating benefits.*

[page 274]

**2. Legal Considerations**

**Issue #1**

*Does the evidence support an NF-85 rate based on the Initial Decision issued by Federal Energy Regulatory Commission Administrative Law Judge David W. Miller, and is it prudent to base the NF-85 rate on this decision?*

**Summary of Positions**

On November 27, 1984, Federal Energy Regulatory Commission Administrative Law Judge David W. Miller issued his Initial Decision in the first hearing held under section 7(k) of the Northwest Power Act. 29 FERC ¶63,039 (FERC Docket Nos. EF81-2011-003 and EF82-2011-003). Judge Miller's decision, *inter alia*, established the cost basis of the nonfirm energy rate, and addressed a wide variety of other issues. The Initial Decision disapproved the BPA's 1981 and 1982 nonfirm energy rates for extraregional sales because "[t]he nonfirm customers were *grossly undercharged* for energy and this violated the fairness principle of cost allocations encompassed … within the lowest possible rates to consumers consistent with sound business principles' requirement found in statutory standards." (emphasis added) 29 FERC 1165,122. Moreover, "BPA should have, but did not establish rates for nonregional nonfirm energy for the NF-1 and NF-2 periods so as to recover the costs attributable to that energy from those buying the energy." Id. at 65,120. As a result of the low rate and in accurate forecast, "BPA came up short in revenue and could not pay on its Federal debt and had its deferred interest payments increase." Id. at 65,122.

In its rebuttal testimony in this case, to the extent possible, BPA conformed the proposed NF-85 rate to Judge Miller's Initial Decision. Parties have argued that BPA should not have conformed the NF-85 rate to the Miller decision as that decision is only initial, and may be altered by the Commission or the courts. The parties have also argued that by so doing BPA is violating its statutory obligation to base its rate decisions on the record established through section 7(i) of the Northwest Power Act. Initial Brief, PSP&L, B-PS-01, 4-5; Reply Brief, CPUC, R-CP-01, 4; Hull, SCE, E-CE-04SR, 1; Reply Brief, SCE, R-CE-01, 2, 5-8, 17; Kemp, PG&E, E-GA-03SR, 1-2; Reply Brief, PGE, R-GA-01, 5; Reply Brief, CEC, B-CC-02, 18-19. Finally, PSP&L argues that BPA should not be guided by the Miller decision, as that decision is directed only at rates for sale of nonfirm energy outside the region. Initial Brief, PSP&L, B-PS-01, 4-5; Reply Brief, PSP&L, R-PS-01, 6-7.

**Evaluation of Positions**

BPA's initial proposal contained a cost-based rate similar to the NF-2 rate before Judge Miller. After the Miller decision was issued, but before cross-examination, BPA filed rebuttal testimony to adjust the NF-85 rate to track the Miller decision. Generally, Judge Miller altered the NF-2 rate to include exchange costs, and to place a limit on the amount of thermal capacity [page 275] costs. In addition to the opportunity for cross-examination, the parties had an opportunity to file surrebuttal testimony in response to BPA's rebuttal testimony.

The evidence in the record supports the assignment of costs and the rate design reflected in NF-85. This evidence is discussed throughout this chapter. The Administrator satisfies his obligation under section 7(i) by basing his final decision on the record.

Using the evidence presented in the record, it is prudent to conform the NF-85 rate to the Miller decision. The Commission decision in the Miller docket will govern nonfirm energy rates developed after 1982, including BPA's 1983 Nonfirm Energy rate (NF-83) now pending before the Commission in 7(k) hearing (Docket No. EF84-2011-006) and NF-85. Unless altered by the Commission or the courts, Judge Miller's well-reasoned decision will stand.

The parties are correct that BPA is not obligated to follow the Miller decision and that the decision may not stand. To the extent that the decision is reversed, BPA's and NF-85 rate may in turn have to be revised. However, the decision is comprehensive and well-reasoned. In the meantime, because the record supports a rate based on the Miller decision, it is prudent to rest upon such a rate, rather than to speculate upon future Commission or court action. Moreover, NF-1, NF-2, NF-83 and the Miller rate, although to different degrees, all differ from one another. Absent a necessary circumstance, it would be imprudent to create in this case another variation of BPA's cost-based nonfirm energy rate before the final outcome of the Miller decision.

Finally, PSP&L is correct that a 7(k) hearing before the Commission considers the lawfulness of only nonfirm energy rates for sales of energy outside the Pacific Northwest. However, in the Miller case, as in this case, BPA did not have separate nonfirm energy rates for regional and extraregional nonfirm energy sales. Moreover, BPA has only one nonfirm energy product. There is no such thing as regional nonfirm energy versus extraregional nonfirm energy. Hence, it is not surprising that Judge Miller addressed issues common to both regions. For example, the Judge found that the cost of BPA's nonfirm energy was the same for both regions. 29 FERC at 65,103.

PSP&L's argument that BPA must develop regional nonfirm energy rates by an independent, separate legal and factual analysis is misplaced. Reply Brief, PSP&L, R-PS-01, 7. The Administrator must apply the same statutory standards in setting extraregional nonfirm energy rates and regional rates. Neither section 7(k) of the Northwest Power Act nor any other statute establishes for either region separate legal standards with respect to nonfirm energy rates. The Regional Preference Act results in marketing practices germane to the sale of BPA power and energy, not just nonfirm energy. As for a separate factual analysis, such an approach is impossible when a single nonfirm energy product is marketed under the same schedules. Neither PSP&L nor any other party to this case has advocated that BPA have different nonfirm energy rate schedules for the Pacific Northwest and the Pacific Southwest. As the extensive text of [page 276] this chapter demonstrates, however, BPA's nonfirm energy rates take into account factual differences between the regions, as well as factual similarities. An example of this is sales of NF-85 Low Cost Displacement rate energy, which is projected to be sold only in the Northwest.

**Decision**

*The evidence supports an NF-85 rate based on the Miller decision, and it is prudent to conform the rate as much as possible to that decision.*

**Issue #2**

*Are BPA's nonfirm energy rates required to be cost-based?*

**Summary of Positions**

BPA took the same position in this case that has been adopted in the past: BPA's nonfirm energy rates need not be based on costs.

CPUC asserts that both statutory and practical considerations require that rates charged nonregional customers be based solely on the cost of providing them service. In particular, CPUC asserts that section 7(k) mandates that BPA recover from nonregional customers only those costs incurred to serve them. Initial Brief, CPUC, B-CP-01, 5-8. The CPUC also asserts that the standards adopted by BPA pursuant to Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §2601 (PURPA), require that BPA's nonfirm energy rates be cost-based. Initial Brief, CPUC, B-CP-01, 8-9. LADWP makes similar arguments. Initial Brief, LADWP, 8-LA-01, 10.

SCE contends that nonregional nonfirm rates are required by statute to be based on the cost of producing nonfirm energy. Initial Brief, SCE, B-CE-01, 5-6. A corollary of this argument is that value-based share-the-savings rates such as 53-85 are unlawful. Reply Brief, SCE, R-CE-01, 45.

**Evaluation of Positions**

The California parties' arguments are virtually identical to those asserted in prior proceedings before the Administrator, and rejected in prior Records of Decision. These arguments have also been presented to and rejected by Judge Miller. 29 FERC ¶63,039, 65,078-81.

Essentially, the California parties argue that applicable statutory standards and BPA's PURPA standard mandate that rates charged for sales of nonfirm energy be based on costs. These arguments are misplaced.

***The statutory standards which govern the Administrator's ratemaking permit a variety of rate methodologies; they do not require that rates be based on cost of service principles.***
[page 277]
The substantive ratemaking standards contained in the three statutes listed in section 7(k) do not address the issue of whether any particular rate must be based on costs. They speak to

revenue sufficiency, that is, whether, BPA's rates yield sufficient revenues. These standards simply require that BPA's rates be *as low as possible consistent with sound business principles so long as they are cumulatively high enough to recover the Federal debt plus other costs, while encouraging the widest possible use of electricity.*

Of the three applicable statutes, the first enacted was the Bonneville Project Act of 1937. 16 U.S.C. §832. Legislative history of the Bonneville Project Act, BPA's original enabling legislation, is replete with Congressional concern that the Federal investment be repaid, but noticeably devoid of reference to any particular rate design method, including cost of service. Indeed, a sponsor of the bill stated that "[i]t has long been congressional policy not to express any exact or fixed rate formula in any bill, but to control and check by regulation." *Columbia River (Bonneville Dam) Oregon and Washington Hearings on H.R. 7642 before the House Comm. on Rivers and Harbors*, 75th Cong., 1st Sess. 181 (1937).

The plain words of the statutes enacted subsequent to the Bonneville Project Act, and their legislative histories, simply reiterate existing standards. As such, they added no specific directive that rates must be based upon cost or any other particular design or methodology. Regarding the Transmission System Act, *see* H.R. Rep. No. 1375, 93rd Cong., 2d Sess. 5 (1974); regarding section (a)(1) of the Northwest Power Act, *see* S. Rep. No. 272, 96th Cong., 1st Sess. 31 (1979) and H.R. Rep. No 976, Part II, 96th Cong., 2d Sess. 52 (1980); regarding Northwest Power Act Section 7(k), *see* H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 70 (1980) and H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 53 (1980).

***Reviewing against identical standards, the Commission has approved a variety of rate designs for other federal power marketing administrations.***

Under the four-part standard of review for BPA, identical to the standard against which it has reviewed the rates of other power marketing administrations, the Commission has approved rates based on a variety of economic theories and pricing practices, including value-base share-the-savings rates. *See Southeastern Power Administration*, 15 FERC ¶61,048 (1981); *U.S. Secretary of Energy, Southeastern Power Administration*, 22 FERC ¶62,025 (1983); *Accord U.S. Secretary of Energy, Western Area Power Administration*, 25 FERC ¶62,232 (1983); *Nantahala Power & Light Co.*, 22 FERC ¶61,209 (1983) (TVA purchases economy energy on a share-the-savings basis).

***A United States District Court has determined that these statutes do not mandate cost as the only basis upon which rates may be computed.***

In *Pacific Power & Light Co. v. Duncan*, 499 F.Supp. 672, 683 (D.Or. 1980), the court noted regarding section 7 of the Bonneville Project Act and BPA's PURPA 111 Order, 44 Fed. Reg. 68,948 (1979):

[page 278]

> Despite all the references to cost, the two quoted passages do not support an inference that cost is the *only* basis upon which rates may be computed. The qualifying phrases "having regard to," "may include," and "to the maximum extent practicable," indicate that the discretion granted in 16 U.S.C. §§825s, 832e. [and] 8389; … were not significantly altered by the requirement to *consider* costs

> in calculating rates. …This BPA regulation, promulgated pursuant to … [PURPA Section 111] has not been violated because the BPA *considered* cost-of-service factors in its calculation of rates. That is all the PURPA requires.

Examining the very statutes which the Administrator must apply in setting rates, including those applicable to sale of nonfirm energy outside the PNW, the court found nothing to restrict the Administrator to any particular rate design methodology or theory; on the contrary, it recognized that the Administrator would always consider a variety of other factors in addition to cost. Id.

***Congress knew how to mandate a cost-based rate and did so for certain firm rates, but not for nonfirm rates applicable outside the Region.***

When Congress was considering the Northwest Power Act, it recognized that BPA had a Share-the-Savings rate in place under the statutes governing BPA at the time. 126 Cong. Rec. H9850 (daily ed. Sept. 29, 1980) (letter to Secretary Duncan from California delegation, specifically describing the rate as based on value rather than cost and not providing a fixed rate, but a flexible formula). In the Northwest Power Act, Congress explicitly required certain rates to be based on specified costs. *E.g.* 16 U.S.C. §839e(b)(1), 16 U.S.C. §§839e(c) and (f).

Thus, Congress knew how to require a cost basis for a specific rate, and knew that under BPA's then-applicable governing statutes BPA was administering a rate based on share-the-savings principles. Nonetheless, Congress, instead of writing a cost-based standard, required that those same statutes, with their broad ratemaking standards, govern extraregional nonfirm energy sales. It could hardly be clearer that Congress did not intend to mandate cost-based rates, or any particular rate design, through the statutes referred to in section 7(k).

***PURPA***

CPUC erroneously concludes that BPA's PURPA standard requires BPA’s nonfirm energy rates to be cost-based. Such a conclusion is not warranted by the standard adopted by BPA, or by the statute. The standard requires only that the Administrator *consider* costs in designing rates:
[page 279]

> The rate design will always consider such an embedded cost-of-service analysis but will also consider other factors, such as marginal or long-run incremental cost principles, the purposes of conservation, efficient use of resources, and equity, and the need to meet legal considerations.

Furthermore, section 111 of PURPA requires only the consideration of specified rate standards in order to "make a determination whether or not it is appropriate to implement such standard… 16 U.S.C.§2621a. Finally, the United States District Court concluded in *Pacific Power and Light Co. v. Duncan*, that BPA's PURPA standard does nothing more than require that BPA *consider* cost-of-service factors in its calculation of rates. 499 F.Supp. 672 (1980).

As this chapter indicates, BPA has met its PURPA standard in designing both its NF-85 and SS-85 rates. The NF-85 rate is a cost-based rate. The SS-85 rate, *inter alia*, considers the recovery of the costs of nonfirm energy, and considers equity by sharing the benefits of BPA's nonfirm energy between BPA and the purchaser.

***Judge Miller's Decision***

Essentially all of the California parties' legal arguments in this case that BPA's nonfirm energy rates must be cost-based were offered and rejected in the Miller case. 29 FERC ¶63,039, 65,078-81.

**<u>Decision</u>**

*The statutory standards which govern the Administrator's ratemaking and the BPA's PURPA standard permit a variety of rate methodologies. They do not require that rates be based on cost-of-service principles, nor do they proscribe value-based share-the savings rates.*

**<u>Issue #3</u>**

*Did Congress mandate cost-based rates through recent appropriation actions?*

**<u>Summary of Positions</u>**

SCE argues that section 506 of the Energy and Water Development Appropriations Act, Public Law 98-50, is a specific Congressional prohibition of non-cost-based rates for BPA. Reply Brief, SCE, R-CE-01, 48.

**<u>Evaluation of Positions</u>**

Section 506 of the Energy and Water Development Appropriation Act of 1984, Pub. L. No. 98-50, 97 Stat. 247 (1983), cited by the SCE as prohibiting Commission consideration or BPA implementation of non-cost-based rates, has no
[page 280] bearing on this case. This statutory provision was sponsored by *Northwest* members of Congress to stop Administration efforts to propose requiring PMAs to sell all their power at a "market" rate. *See*, *e.g.*, 128 Cong. Rec. H7282-83 (daily ed. Sept. 20, 1982) (remarks of Reps. Gore, Wyden, and Pritchard).

Congress perceived that the Niskanen study was aimed at requiring PMAs to produce revenues in excess of their overall revenue requirements, and acted to prevent this. Congress added language virtually identical to that of section 506 to the Continuing Appropriation for 1983. 128 Cong. Rec. S12,573 (daily ed. Sept. 29, 1982). Senator McClure's comments at the time of that initial reaction clearly show Congress' limited and specific purpose:

> Mr. President, there has been a good deal of play in the press of late about a study which is currently being conducted … of the hydro electric power pricing policies of the Federal public power authorities and other agencies of the Federal Government. The purpose of the study, … is to look *to the possibility of raising*

> *revenue for the Federal Government* by increasing the price of the power sold by these marketing agencies…
>
> Mr. President, *I at no time recall that it was our intention that the pricing policies and methods of TVA, BPA, or the other Federal Power marketing agencies be tampered with as a source of new revenue by shifting to a market price method of pricing as opposed to the cost method currently required*. I do not consider such an important and fundamental shift in policy to be an appropriate subject of such study without the full knowledge and involvement of the Congress…

128 Cong. Rec. S12,573-574 (daily ed. Sept. 29, 1982) (emphasis added).

The "currently required at cost" method of pricing directive of section 506 is enunciated in similar language in the three statutes enumerated under section 7(k) and in section 7(a) of the Northwest Power Act, and goes to the recovery of *overall* system costs. It directs BPA to set the lowest possible rates which cumulatively yield sufficient revenues to repay the Federal investment and other costs. It does not address the design of individual rates.

Congress' purpose in section 506 of Pub. L. 98-50 was straightforward. Congress was not concerned with existing share-the-savings rates, such as BPA's energy broker rate. Nor was Congress concerned about Commission consideration of individual Share-the-Savings rate structures for PMAs. In fact, since passage of Pub. L. No. 98-50, the Commission confirmed and approved WAPA's split-savings rate schedule RCP-1. 25 FERC ¶62,232 (1983). Congress only intended to protect existing limitations on each PMA’s total revenue requirement, thus reaffirming, in BPA's case, section 7(a)(2) of the [page 281] Northwest Power Act, which the Commission had already interpreted to govern BPA’s total revenue requirements and not individual rates. *See* Order Resolving Scope of Commission Jurisdiction, 20 FERC ¶61,292 (1982).

SCE also presented this argument to Judge Miller, who rejected it. 29 FERC at 65,080.

**<u>Decision</u>**

*Congress did not mandate cost-based BPA rates through section 506 of the Energy and Water Development Appropriations Act.*

**<u>Issue #4</u>**

*Does Section 7(g) of the Northwest Power Act require exchange resource costs to be allocated to regional and firm power rates, and be excluded from nonregional, nonfirm power rates?*

**<u>Summary of Positions</u>**

PG&E contends that section 7(g) of the Northwest Power Act requires exchange resource costs to be allocated to regional and firm power rates, and not to nonfirm energy rates. Kemp, PG&E, E-GA-02R, 6.

**Evaluation of Positions**

PG&E's assertion that the costs of the residential exchange should be borne soley [sic] by firm customers and regional customers is not warranted by the Northwest Power Act. Section 7(g) indicates that costs not otherwise allocated be assessed to "power rates ". Section 7(k) refers to nonfirm energy as "nonfirm electric power." There is no indication that Congress intended the term "power" referred to in section 7(g) to have any different meaning than the term as used in Section 7(k): "rates or rate schedules for the sale of nonfirm electric power". Thus, section 7(g) does not indicate that resource exchange costs should not be allocated to nonfirm rates.

PG&E's argument is also inconsistent with the decision of Judge Miller that section 7(g) appears to mandate that exchange costs be rolled into all rates. 39 FERC at 65,095.

**Decision**

*Section 7(g) of the Northwest Power Act does not prohibit exchange resource costs from being allocated to nonfirm rates.*

**Issue #5**

*Did the Commission reject BPA's 1979 Share-the-Savings rate?*
[page 282]
**Summary of Positions**

SCE contends that the Commission rejected BPA's 1979 H-6 Share-the-Savings rate because it violated statutory standards. Reply Brief, SCE, R-CE-01, 46.

**Evaluation of Positions**

SCE contends that the order approving BPA's 1979 rates rejected a value-based, share-the-savings methodology. In that order the Commission found that BPA's H-6 Share-the-Savings rate schedule "was not designed in a manner that would permit the Commission to understand the logic of the allocation of cost and revenue requirements among the various rate schedules." However, because a cost-based rate justified the rate actually charged, final confirmation and approval was granted. 23 FERC ¶61,342, 61,740 (1983). Far from rejecting the overall methodology, the Commission simply found a satisfactory basis for concluding that the H-6 rate conformed with applicable statutory standards, notwithstanding shortcomings perceived in BPA's support of the rate.

SCE quotes the following language from the same order: "Such methodology … violates the criterion that Bonneville's rates be drawn to provide the lowest possible rates to consumers consistent with sound business principles." *Id*. at 61,741. SCE misreads the order, because the language they quote comes from a section of the order dealing with BPA's F-7 schedule for firm capacity sales. 23 FERC at 61,741. It is undisputed that a cost basis is appropriate for many firm services, particularly where they are for sales to requirements customers. However, one cannot generalize from that conventional wisdom to a conclusion that all rates must be cost-based.

The Miller decision considered and rejected the argument SCE presents here. 29 FERC at 65,080.

**Decision**

*The Commission did not reject BPA's 1979 Share-the-Savings rate.*

**Issue #6**

*Is a Share-the-Savings rate supported by Commission policy?*

**Summary of Positions**

SCE argues that Commission policy does not support the use of a Share-the-Savings rate in a case such as BPA's. Reply Brief, SCE, R-CE-01, 48-51. The Northwest Parties take the position that share-the-savings rates represent standard utility practice for economy energy sales throughout the United States. Reply Brief, NWP, R-NF-01, 1.

[page 283]

**Evaluation of Positions**

Citing *Public Service Co. of New Mexico*, 25 FERC ¶61,469, SCE implies that Commission policy would not support BPA's SS-85 rate because of the alleged absence of: (1) economic efficiency; (2) incentive to the seller, and (3) competition. Reply Brief, SCE, R-CE-01, 49-50. Assuming *arguendo* that *New Mexico* does stand for such a proposition, the record amply demonstrates that all three of these factors are present in this case. Economic efficiency and competition are discussed elsewhere in this chapter. SCE's argument that BPA's incentive is determined by statutory preference, not price, is incorrect. The availability of BPA nonfirm energy for sale outside the PNW is clearly affected by its price.

First, the price of BPA's nonfirm energy affects BPA's operational decisions and long term planning. In other words, BPA needs an incentive to refrain from decisions that will lessen the amount of nonfirm energy made available. Second, the higher the price that nonfirm energy can command, the more likely BPA is to sell and bear the risk of having to operate a higher cost resource at a later time to replace that energy. Finally, a higher price will result in fewer purchases by PNW utilities, and therefore, greater availability for the PSW.

The Northwest Parties are correct that share-the-savings is widely accepted and routinely approved by the Commisssion [sic]. *See e.g., American Electric Power Service Corp.*, 8 FERC ¶61,068, 61,225 (1979) ("split-savings method is one of a variety of reasonable methods for allocating the savings derived from economy energy transactions"); *Wisconsin Public Service Corp.*, 22 FERC ¶63,088, 65,303 (1983) ("split-the-savings rates have gained general acceptance"). The Commission has approved share-the-savings rates for other power marketing agencies. *U.S. Secretary of Energy, Western Area Power Administration*, 25 FERC ¶62,232 (1983); *Nantahala Power and Light Co.*, 22 FERC ¶61,209 (1983) (TVA purchases economy energy on a share-the-savings basis). California utilities, including SDG&E, SCE, PG&E and LADWP, routinely use share-the-savings rates. Opatrny, NWP, STR 1310-1311.

**Decision**

*Share-the-savings rates in general, and in BPA's circumstance, are supported by Commission policy.*

**Issue #7**

*Do nonfirm energy rate components, which allow for nonfirm energy sales below cost, constitute predatory pricing?*

**Summary of Positions**

The NGU contends that BPA's proposed below-cost nonfirm energy rate components will result in unlawful predatory pricing in violation of the [page 284] Robinson-Patman Act. Initial Brief, NGU, B-WG-01, 1-3. The NGU argues that, in economic terms, BPA's NF-85 rate schedule constitutes predatory pricing because some rate components are set below "profitable levels" in order to undercut competition. Conkling, NGU, E-WG-01, 18. NGU asserts that, except for the Standard rate, BPA ignores the admonition of the initial 7(k) decision that departures from cost-based rates must be justified by reliance on "specific economic precepts." Conkling, NGU, E-WG-07SR, 4-13.

BPA does not believe that NF-85 constitutes predatory pricing. BPA notes that none of the components inherent in price predation is present in this case. Metcalf, BPA, E-BPA-64R, 19.

**Evaluation of Positions**

As a matter of law, BPA, as a federal agency, is not subject to the Robinson-Patman Act. *Department of Water and Power of the City of Los Angeles v. BPA*, No. 84-7618, slip op. at 20, n. 12 (Ninth Circuit, filed April 24, 1985). However, because of the importance of the policies expressed by the Robinson-Patman Act and the other antitrust laws, BPA believes it is appropriate to consider the potential anticompetitive effects of certain actions it may take. Upon consideration of the arguments raised by the NGU that components of NF-85 restrain competition and constitute predatory pricing, BPA concludes that these arguments are without merit.

The NGU is critical of BPA's departure from cost considerations in designing the NF-85 rate schedule and charge that the "specific economic precepts" and applicable statutory standards necessary to support such departures are not in evidence. Conkling, NGU, E-WG-07SR, 14. Furthermore, the NGU contends that BPA is pricing its nonfirm energy at levels lower than its competitors' long-run marginal costs, a situation which they predict will harm competitors. Conkling, NGU, E-WG-07SR, 20. NGU contends that the price difference is unwarranted: a kilowatt-hour at 20 mills is no different in quality from one sold at 7 mills. The NF-85 price differentials are allegedly unjustified because they rest on a "quality of kilowatt-hour" argument instead of a "quality of service" argument. This situation, according to the NGU, constitutes predatory pricing. Conkling, NGU, E-WG-01, 16.

As a matter of economics, NGU has not properly defined predatory pricing. It is well established that "predation in any meaningful sense cannot exist unless there is a temporary sacrifice of net revenues in the expectation of future gains. Indeed, the classically feared case of predation has been the deliberate sacrifice of present revenues for the purpose of driving rivals out of the market and then recouping the losses through higher profits earned in the absence of competition." Areeda & Turner, *Antitrust Law*, Vol. III, ¶711, p. 151. There is nothing of this sort present in this case. NGU has neither alleged nor demonstrated that NF-85 will cause a temporary reduction in BPA's net revenues or that any such reduction will be subsequently recouped through "higher profits." Similarly, NGU has not demonstrated that the purpose of NF-85 or any of its components is to drive rivals out of the market. In fact, BPA has expressly testified that the "intent to eliminate competition is not [page 285] present [and] the actual elimination of competition is practically impossible." Metcalf, BPA, E-BPA-64R, 19. BPA's purpose in offering nonfirm energy at below-cost rates is to market energy that might otherwise be spilled or go unsold at cost-based rates. Griffin, BPA, STR 970.

Moreover, the NGU has not demonstrated that BPA's nonfirm rates are inconsistent with the organic statutes that govern BPA's ratemaking. Many of the arguments offered in support of NGU's "economic precepts" theory are based on textbook and dictionary definitions of economic terms, and were admitted to have no support in empirical investigation. Metcalf, BPA, E-BPA-64R, 18; STR 2159-2160, 2166. Rate schedule components which allow BPA to charge prices for its nonfirm energy below-cost when there is not a market for such energy at cost are consistent with BPA's statutory duties to establish rates consistent with sound business principles, encourage widespread use, recover total system cost, and repay the Federal Treasury over a reasonable period of years. 16 U.S.C. 832f, 8389, 839e, 839e(a)(2). Below-cost rate components prevent BPA from spilling water and losing revenues when BPA is unable to market its nonfirm energy at cost. Indeed, the initial 7(k) decison [sic] recognized that BPA may have to sell nonfirm energy below cost at certain times. 29 FERC at 65,080.

**<u>Decision</u>**

*Neither NF-85 nor any component of NF-85 constitutes predatory pricing. The fact that a component of a rate schedule is below cost does not create price predation. The NGU has not demonstrated that any of the fundamental elements inherent in a price predation situation are even remotely present in this case. By pricing a component of NF-85 below cost, BPA has absolutely no intention of restraining or eliminating competition for nonfirm energy sales. Indeed, such a result is virtually impossible. NGU's arguments that NF-85 is contrary to the Robinson-Patman Act are rejected.*

**<u>Issue #8</u>**

*Does BPA's NF-85 rate schedule discriminate between regional and nonregional purchasers of nonfirm energy, or among regional purchasers?*

**Summary of Positions**

SCE, PG&E, CEC, and LADWP contend that the NF-85 rate schedule discriminates against PSW purchasers of nonfirm energy. These parties raise essentially two arguments. First, they contend that NF-85 is "extremely complex" and gives the Administrator virtually "unlimited discretion" to discriminate between nonfirm energy purchasers. Initial Brief, SCE, B-CE-01, 26; Reply Brief, SCE, R-CE-01, 11-14; Initial Brief, PG&E, B-GA-01, 7-8.

Second, the California parties argue that NF-85 is discriminatory because PSW utilities will not have access to lower-priced NF-85 rates, while PNW utilities will. Initial Brief, PG&E, B-GA-01, 8; Reply Brief, PG&E, R-GA-01, 2-4; Initial Brief, CEC, B-CE-01, 21; Reply Brief, LADWP, R-LA-01, 5-6. As a
[page 286] consequence, these parties contend that while PSW utilities will be purchasing BPA nonfirm energy at the Standard rate, PNW utilities will be purchasing the same energy at the lower NF-85 displacement rates. *Id*.

NGU contends that BPA’s proposed Share-the-Savings rate component of the NF-85 rate schedule is discriminatory primarily because BPA’s rates are based on the individual purchaser's decremental cost of displaceable resources. Conkling, NGU, E-WG-01, 1, 18; E-WG-07SR, 1; Initial Brief, NGU, B-WG-01, 1-4. The NGU claims that BPA’s share-the-savings components discriminate because they do not have separate rate components for thermal generation displacement and displacement of end-user alternate fuels. Reply Brief, NGU, R-WG-01, 2-3, 9-10. The NGU supports the Share-the-Savings rate proposal set forth by the Northwest Parties. *Id*. at 4.

**Evaluation of Positions**

Parties argue that the complexity and discretion inherent in the NF-85 rate would allow BPA to discriminate among nonfirm energy purchasers. This argument is not correct. The complexities of the NF-85 rate schedule were introduced to allow BPA to recover its cost to the extent possible while still efficiently displacing thermal resources. Similarly, discretion is needed to allow BPA to react to the myriad of possible market and supply conditions. Nevertheless. BPA never proposed to give itself unlimited discretion in implementing the NF-85 rate. All sales at the below-cost components are predicated on the purchasers actually backing down resources that are not economic to displace at the Standard rate (the only exception is when BPA makes the High Cost Displacement rate available to all purchasers).

In addition, BPA has revised the NF-85 rate schedule in response to criticisms made by the parties. The rate schedule has been simplified by eliminating the Variable Displacement rate. Marketing procedures have been clarified by requiring the market to be saturated at higher rates before nonfirm energy is offered at lower rates.

The NGU and NWP criticize BPA’s proposed share-the-savings component of NF-85. As the share-the-savings component of NF-85 (Variable Displacement rate) has been removed, the only share-the-savings component that remains in BPA's nonfirm energy rate proposal is in the

SS-85 rate. No sales will occur at the SS-85 rate until contracts have been negotiated and executed. Matters concerning the implementation of the 55-85 rate may arise during the course of entering into these contracts, which may necessitate a public involvement process pursuant to section 7(i) of the Northwest Power Act. It is therefore premature for BPA to reach a final decision on the discrimination issues raised by the PSW utilities or the NGU regarding the Share-the-Savings rate at this time.

The second discrimination argument raised by the California parties is that NF-85 is discriminatory because it precludes PSW utilities from access to lower cost Displacement rate energy but permits such sales to PNW utilities. In support of this argument, SCE and PG&E quote testimony of BPA that BPA
[page 287] projected no sales to the PSW at BPA's Low Cost Displacement rate because PSW utilities will likely saturate the Intertie with Standard rate energy, and therefore preclude nonfirm sales at the lower priced Low Cost Displacement rate. BPA disagrees that this situation would give rise to a valid claim of discrimination.

It must be emphasized that NF-85 and each component of NF-85 apply on an equal basis to all BPA customers. There is no distinction inherent in NF-85 that treats PSW customers with disfavor. Nevertheless, the California utilities contend that while the language of NF-85 may not discriminate per se against them, the practical effect of NF-85 is to preclude PSW utilities but not PNW utilities from access to lower cost displacement rate energy. BPA does not deny that at times, PNW utilities will likely purchase nonfirm energy at the Low Cost Displacement rate while PSW utilities will purchase at the Standard rate. BPA does not believe, however, that this potential rate disparity constitutes discrimination.

Discrimination exists when the same product is sold to similarly situated customers at different prices. *Public Service Co. of Indiana v. FERC*, 575 F.2d 1204, 12111-12 (7th Cir. 1978); *Central Illinois Public Service Co.*, 20 FERC 61,043, p. 61,084 (July 12, 1982). In this case, the PSW utilities and PNW utilities are not similarly situated. The most glaring and overriding distinction between BPA energy sales to PSW and PNW utilities is the differing nature of the market for nonfirm energy in the two regions. The primary market for nonfirm energy in the PSW is for displacement of high incremental cost oil and gas generation. This generation can be displaced economically at BPA's cost-based Standard rate. On the other hand, the primary market for nonfirm energy in the PNW is lower incremental cost coal displacement. This generation cannot be displaced at BPA's cost-based Standard rate. In a situation where a PNW utility were similarly situated to PSW utilities -- namely, it is displacing a resource with incremental cost greater than the Standard rate plus 2 mills per kilowatt-hour -- the NF-85 rate schedule would require that utility to pay the Standard rate. Similarly, if a PSW utility were similarly situated to the PNW norm -- namely, no high cost displaceable resources are on line and the utility wishes to purchase nonfirm energy to displace resources or purchases with decremental costs below the Standard rate plus 2 mills per kilowatt-hour -- that utility would be eligible to purchase at the below-cost NF-85 displacement rates after all Standard rate markets were satisfied. Indeed, just such a situation is expected to occur in the PSW occasionally during offpeak hours, and the High Cost Displacement rate was explicitly designed to handle that situation.

The other difference between sales to the regions is that PNW sales do not require Intertie capacity, whereas PSW sales cannot take place without it. The Intertie, being the conduit for all power transmitted to the PSW, is the single greatest physical constraint on the extent of BPA energy sales to the PSW. A primary reason PNW utilities may make NF-85 displacement rate purchases while the PSW may not is the Intertie's limited capacity. Griffin, BPA, 51R 968.
[page 288]
For instance, NF-85 Low Cost Displacement rate energy will not be available to either PNW or PSW utilities unless all markets are first satisfied at the Standard rate or the High Cost Displacement rate. This limitation on the sale of Low Cost Displacement rate energy exists because the Low Cost Displacement rate was developed as a market expansion device. Griffin, BPA, STR 970-71. It is to be offered when BPA is seeking more load to increase revenues or to avoid or eliminate the occurrence of spill conditions. *Id*. The California utilities are concerned that, if all markets are satisfied at higher rates before BPA markets nonfirm at the Low Cost Displacement rate, there will most likely be no Intertie capacity available for displacement rate sales to the PSW. However, any constraint placed upon PSW access to Low Cost Displacement rate energy is not a product of the NF-85 rate schedule. It is a product of the nature of the PSW market and the limited Intertie capacity. Clearly, if the Intertie had limit less physical capacity and if decremental costs were similar in the two regions, PSW utilities could potentially purchase Low Cost Displacement rate energy with the same frequency as PNW utilities.

Finally, it is argued that the decremental cost limits for qualification for the displacement rates constitute discrimination. Reply Brief, NGU, B-WG-01, 3. This argument, if valid, would apply to all Share-the-Savings rates. Yet share-the-savings rates have been consistently found to be legal and nondiscriminatory. *See* Issue #6, above. The NF-85 rate is designed to resemble a Share-the-Savings rate for the components below the cost-based Standard rate. The fixed nature of these components will make the rate schedule easier to administer.

Moreover, assuming *arguendo* NF-85 does create a rate disparity that is discriminatory, other factors must be considered. First, BPA's organic statutes do not contain a restriction against discrimination in setting wholesale power rates. Second, even if the the [sic] letter or spirit of the law pertinent to utility ratemaking discrimination were somehow applicable to BPA, that law only proscribes undue discrimination. A rate disparity, by itself, does not create *undue* discrimination. *Cities of Bethany v. FERC*, 727 F2d 1131, 1139 (DC Cir. 1984); *St. Michaels Utilities Comm'n v. FPC*, 377 F2d 912, 915 (4th Cir. 1967). On the contrary, it is well established that differences in rates are justified where they are predicated upon differences in costs. *Id*.

In addition to the Intertie constraint, BPA is constrained by its statutory obligation to establish the lowest possible rates consistent with *sound business principles*, recover total system costs, and repay the Federal investment in the Federal Columbia River Power System over a reasonable period of years. 16 U.S.C. 832f, 838g, 839e, 839e(a)(2). BPA cannot market energy in a manner that defeats rather than promotes these objectives. If PSW demand for nonfirm energy permits PSW markets to be satisfied at BPA's cost based
[page 289] Standard rate, it would be economically irrational for BPA to market that energy below cost. Thus, it would be inconsistent with sound business principles for BPA to sell nonfirm energy to the PNW or PSW at the below-cost Low Cost Displacement rate unless all markets were first satisfied at the Standard rate or the High Cost Displacement rate. Conversely, it does

comport with sound business principles for BPA to sell below cost in order to expand its market, avoid spilling marketable energy, and recover additional revenue that would otherwise be lost. Moreover, such below-cost nonfirm sales enhance BPA's ability to recover total system costs and repay the Federal Treasury.

**Decision**

*BPA's NF-85 rate schedule is not discriminatory. It applies with equal force to regional and extraregional customers alike. The fact that PSW utilities may be restricted in their ability to purchase nonfirm energy at BPA's lower displacement rate is not a function of the NF-85 rate schedule; it is a function of PSW saturation of Intertie capacity at the Standard rate. Moreover, BPA's organic statutes do not proscribe discrimination in setting wholesale power rates. Assuming arguendo that a ratemaking discrimination standard applied to BPA, such standard would only prohibit undue discrimination. A rate disparity does not constitute undue discrimination if it is justified by the facts. The most prominent facts that justify a rate disparity in this case are the Intertie's limited capacity and BPA's statutory directives to recover total system costs, repay the Federal Treasury, and establish rates consistent with sound business principles. It is these facts, and not BPA's NF-85 rate schedule, that may result in and justify any price difference for sales of nonfirm energy between PNW and PSW customers.*

**Issue #9**

*Are BPA's nonfirm energy rates inconsistent with Commission dictum regarding revenue crediting?*

**Summary of Positions**

CPUC cites *U.S. Secretary of Energy, Bonneville Power Administration*, 23 FERC ¶61,342, 61,739 (1983), for the proposition that BPA is not authorized to charge a higher price for energy to the PSW than that charged within the PNW. Initial Brief, CPUC, B-CP-01, 7. SCE and LADWP make similar arguments. Initial Brief, SCE, B-CE-01, 28; Reply Brief, LADWP, R-LA-01, 5.

**Evaluation of Positions**

The passage cited has no bearing on the question of whether BPA may charge a higher price for energy in one region. Rather, it has to do with the practice of revenue crediting. Moreover, it is simply dictum:

> The practice of using the income from sales outside the region to offset revenue requirements for sales within the regions *would appear* to require BPA to underprice services within the region, thus providing a price preference between regional and non-regional sales which has no basis in the applicable statutes.

[page 290]

*Id*. at 61,739 (emphasis added).

The Commission was referring to BPA's practice of revenue crediting, whereby all costs are allocated to firm power customers, and their share of system costs is then reduced by subtracting projected nonfirm energy revenues. Analysis of the entire order, rather than just the passage relied upon by the California utilities, shows that the Commission did not make a finding that revenue crediting creates an unauthorized price preference.

The Commission approved BPA's H-6 nonfirm energy rate, despite its finding that the rate was lower than a cost-based rate would have been. *Id*. at 61,740. The Commission found that BPA did not in fact recoup under the H-6 rate even the level of costs which would clearly be allowable under a cost-based nonfirm energy rate, and stated explicitly that "no customer was subject to a net overcharge." Id. at 61,744. Hence, although the Commission observed in dictum in the early part of the order that revenue crediting would appear to create a price preference, the Commission's actual findings in approving BPA's 1979 rates showed that no price preference was created. Rather, the Commission's findings show that, if anything, BPA's firm power customers under BPA's 1979 rates subsidized all of its nonfirm (regional and nonregional) customers.

**Decision**

*BPA's nonfirm energy rates are not inconsistent with Commission dictum regarding revenue crediting.*

**Issue #10**

*Is the prefiled testimony of Association of Northwest Gas Utilities (ANGU) witness Bruce Ambrose properly in the official record in this proceeding?*

**Summary of Positions**

The Association of Northwest Gas Utilities prefiled the testimony of Mr. Bruce Ambrose for introduction into the record in this proceeding. See WP-85-E-WG-2. The testimony was not admitted to the record during the regularly scheduled hearings for the reason that the witness was unavailable for cross-examination. The record indicates that Counsel for ANGU excepted to the Hearing Officer’s ruling on the exclusion of the testimony and tendered the testimony as an offer of proof for the record. *See*: STR 1620-1621. By motion filed after the close of the hearings, ANGU moved to introduce the testimony into the record. BPA, PPC, and APAC opposed the motion to admit the statement into the record. The motion was denied by the Hearing Officer by order dated February 21, 1985. *See*: O-48. Upon motion of APAC, references to the testimony contained in the Initial Brief filed by ANGU in this proceeding were stricken by order dated March 22, 1985. *See*: O-54.
[page 291]
**Evaluation of Positions**

The rulings of the Hearing Officer denying the motion of ANGU to admit the testimony into the record and striking references to the testimony from the Initial Brief of ANGU excluded the testimony from the record. Hence, the Administrator may not consider that testimony in his decisionmaking.  Counsel's offer of proof, however, is in the record.  *See* Federal Rules of Evidence, 103(b), and Advisory Committee Note.

Not only can the Administrator not consider Mr. Ambrose's testimony because it is outside the record, the witness was unavailable for cross-examination.  Section 7(i)(2)(B) of the Northwest Power Act, 16 U.S.C. 839e(i)(2)(B), affords parties the opportunity to cross-examine witnesses.  Considering the unsworn testimony of a witness not subject to cross-examination would prejudice the rights of other parties.

**Decision**

*The prefiled testimony of ANGU witness Ambrose is not part of the official record of this proceeding.  Counsel's offer of proof is part of the record.*

**Issue #11**

*Is the prefiled testimony of Merrill Schultz part of the official record of this proceeding?*

**Summary of Positions**

PSP&L and WWP prefiled the statement of Merrill Schultz as exhibit WP-85-E-PS/WP-03SR in this proceeding.  Counsel for PSP&L and WWP, however, indicated in the Hearings their intent that the statement not be offered into the record by sponsoring utilities nor considered by the Administrator.  STR 1107 and 1139.  SCE requested admission of the statement to the official Record as an exhibit.  Id.  The Hearing Officer denied admission of the statement to the Official Record as an exhibit.  STR 1172 and 1176-1177.

In its Reply Brief, SCE urges the Administrator to reverse the ruling of the Hearing Officer denying admission into the record of the prefiled testimony of Merrill Schultz, witness for PSP&L.  Reply Brief, SCE, R-CE-01, 54-55.  SCE further contends that the Administrator may consider the document not withstanding the rulings of the Hearing Officer.  Reply Brief, SCE, R-CE-01, 54.  See also, Initial Brief, SCE, B-CE-01, 12.  SCE relies on section 7(i)(5) of the Northwest Power Act, and also upon Section 1010.4 (c)(vii) of Procedures Governing Bonneville Power Administration Rate Adjustments.  Reply Brief, SCE, R-CE-01, 54.

**Evaluation of Positions**

The rulings of the Hearing Officer excluded Mr. Schultz’s prefiled testimony from the record.  Hence, the Administrator cannot consider that
[page 292] testimony in his decisionmaking process.  Unlike the Ambrose situation, discussed in Issue #9, no counsel made an offer of proof.  *See* STR 1172.

Furthermore, as was the case with Mr. Ambrose, Mr. Schultz’s prefiled testimony was not sworn, nor did he appear for cross-examination.  Hence, the procedural requirements of section 7(i)(2)(B) have not been met.

SCE is correct that the Administrator may consider documents and other comments not part of the evidentiary record developed before the Hearing Officer in reaching a decision pursuant to section 7(i)(5) of the Northwest Power Act and Section 1010.4(c)(vii) of Bonneville's procedural rules. The Administrator's consideration of documents not developed before the Hearing Officer, however, is limited to consideration of materials, information, and comments submitted by *participants* to the rate case, and not those submitted by *parties* to the rate case. *See* Section 1010.2(e) and (f) of Procedures Governing Bonneville Power Administration Rate Adjustment. SCE is a party to the rate case. The Special Rules of Practice governing the 1985 Wholesale Power Rate Adjustment Proceedings provide that parties shall not act as participants. *See* O-02, 9.

**Decision**

*The prefiled testimony of Merrill Schultz is not part of the official record in this case.*

### 3. Target Average Revenue and Standard Rate Calculation

BPA's initial proposal set the average Standard rate at BPA's average cost of service with FBS and new resources power excluding thermal capacity costs. BPA, E-BPA-08, 68. The costs assigned to the average Standard rate calculation were reduced by Fixed Displacement rate sales (in subsequent testimony, the Low Cost Displacement rate). *Id*., 69. The Standard rate was diurnally differentiated. *Id*., 68-69.

The Standard rate calculation changed in BPA's rebuttal testimony. The changes were prompted by Judge Miller's Initial Decision, which was issued after BPA's initial proposal. Metcalf, BPA, E-BPA-64R, 21-22. Whereas in the initial proposal the average Standard rate was based on the cost of FBS and new resources power, and on net system loads, the revised proposed Standard rate is a function of (1) a cost-based target average revenue similar in calculation to the average Standard rate, and (2) a "delta" to recover revenues lost through sales at the below-cost High Cost Displacement rate. The revised Standard rate is not diurnally differentiated. The revised Standard rate is designed to recover all assigned costs and, in addition, revenue underrecovery from some below-cost NF-85 sales. Metcalf, BPA, E-BPA-64R, 24.

In BPA's rebuttal testimony, the target average revenue is, with a few exceptions, calculated as the average cost of service with FBS, new resources, and exchange power. Only part of the fully allocated thermal capacity costs
[page 293] is assigned, and Low Cost Displacement rate revenue is credited. The assigned costs are divided by the sum of loads served with FBS, new resources and exchange power, DSI first quartile service with nonfirm energy, and NF-85 sales excluding Low Cost Displacement rate sales. The key changes in cost assignment from the initially proposed Standard rate are: (1) the cost of industrial reserves is no longer included; (2) exchange costs have been added; and (3) some thermal capacity costs are included. Metcalf, BPA, E-BPA-64R, 24, A10.

**Issue #1**

*Should Washington Nuclear Project (WNP) costs be included in the target average revenue?*

**Summary of Positions**

BPA includes all WNP costs in the target average revenue except those thermal capacity costs that exceed the limit included in Judge Miller's Decision. Metcalf, BPA, E-BPA-64R, 24-25.

All California parties objected to the inclusion of WNP costs in the calculation of the NF-85 Standard rate. CEC argues that payments for WNP-1 and -3 are inappropriate, since these units do not affect BPA's ability to provide nonfirm service during the rate period. Marcus, CEC, E-CC-01, 31; Initial Brief, CEC, B-CC-01, 36-38; Reply Brief, CEC, B-CC-02, 22.

SCE argues that the WNP costs should be attributed only to firm power customers, for unlike these customers, nonfirm customers have no assurance of receiving power from these units now or during the period the resources will operate. These units were not initiated for the purpose of selling nonfirm energy. Nonfirm energy customers should not be responsible for fixed costs of any generating facilities. Hull, SCE, E-CE-01A, III-15-17; Initial Brief, SCE, B-CE-01, 32; Reply Brief, SCE, R-CE-01, 15-17.

CPUC argues that WNP-1 will not even affect BPA's firm power supply, let alone nonfirm energy, during the rate period. Enderby and Mattson, CPUC, E-CP-01, 15. They add that WNP-2 is a firm resource intended to meet firm load, Although it is possible that WNP-2, Trojan and Hanford could produce nonfirm energy. Id. PG&E and LADWP also state that the costs are not incurred for the intended benefit of nonfirm customers and since BPA has no long-term commitment to serve nonfirm customers, there is no assurance that they will ever receive energy from these plants. Parmesano and Whitney, LADWP, E-LA-01, 15; Initial Brief, LADWP, B-LA-01, 3; Kemp, PG&E, E-GA-01, 4-5; E-GA-02R, 5.

The Northwest Parties counter this argument with partial support for BPA's revised position. WNP-1, -2, -3 currently contribute, or are expected to contribute, to the availability of nonfirm energy in the same manner as any other thermal plant: more energy available on the entire system means more [page 294] nonfirm energy available for sale. Mizer, NWP, E-NF-01, 39. Even though WNP-1 and -3 will not produce power during the rate period, there is no reason to exclude the current costs of a future resource from the cost-based rates when the current costs of that same resource must be included in the cost-based rates of BPA's firm power customers. The firm power customers are not currently receiving power from these plants. Nonetheless, they too are paying for the availability of a future supply. *Id*., 41.

**Evaluation of Positions**

The California parties argue that WNP costs should not be included in BPA's nonfirm energy rates for four basic reasons. First, only hydro contributes to the availability of nonfirm energy. Hull, SCE, E-CE-01A, II-13; Kemp, PG&E, E-GA-01, 2. Second, fixed costs should not be assigned to nonfirm energy. Hull, SCE, E-CE-01A, III-16; Marcus, CEC, E-CC-01, 21. Third, WNP-1 and -3 were not initiated for the purpose of selling nonfirm energy. Reply Brief, SCE, R-CE-01, 16; Kemp, PG&E, E-GA-01, 5. Finally, WNP-1 and -3 will not be completed during the rate period. Hull, SCE, E-CE-01A, III-16; Enderby and Mattson, CPUC, E-CP-01, 15; Marcus, CEC, E-CC-01, 32-33; Kemp, PG&E, E-GA-01, 5. However, it is clear from the record that nonfirm energy is produced through the coordinated operation of BPA's hydro and thermal resources (Mizer, NWP, E-NF-01,43); that thermal capacity contributes to the availability of nonfirm energy on both an operational and a planning basis (*Id*., E-NF-03R, 4); and that BPA must recover the costs of WNP-1 and -3 from current ratepayers, firm and nonfirm alike. *Id*., E-NF-01, 40.

The record supports recovery of Supply System costs from both firm and nonfirm ratepayers. These plants, when completed, will be used to provide firm and nonfirm energy. Metcalf, BPA, STR 573. These resources contribute to the availability of nonfirm energy sold to the Pacific Northwest. Metcalf, BPA, STR 639. Every addition to thermal baseload capacity preserves the ability to produce nonfirm energy. Metcalf, BPA, STR 820.

Virtually the same issues regarding inclusion of WNP costs in nonfirm energy rates were raised and briefed thoroughly before Judge Miller. Judge Miller concluded that WNP costs were properly allocated to nonfirm energy rates. 29 FERC at 65,094. BPA's proposed allocation of WNP costs to nonfirm energy rates comports with Judge Miller's decision.

**Decision**

*BPA correctly allocates WNP-1 and -3 costs to nonfirm energy. Thermal plants contribute to nonfirm energy availability, and the WNP costs must be recovered from current ratepayers.*

**Issue #2**

*Should capacity costs be included in the target average revenue?*

[page 295]

**Summary of Positions**

BPA includes capacity costs in the NF-85 rate schedule. Purchasers of BPA's nonfirm energy receive a capacity value because they are able to serve firm load over peak hours and displace high incremental cost peaking resources. Metcalf, BPA, E-BPA-37, 6. This position is supported by the Northwest parties because the peaking and storage capability of the coordinated system allows BPA to shape nonfirm energy so that it is more marketable, especially during peak periods. Mizer, NWP, E-NF-03R, 4.

SCE argues that nonfirm energy customers should not be responsible for the fixed costs of any generating facilities. Hull, SCE, E-CE-01A, III-6-8; E-CE-03R, IV-3. However, it may be appropriate to recover through nonfirm energy rates a "reasonable contribution" to fixed costs. Initial Brief, SCE, B-CE-01, 32; Reply Brief, SCE, R-CE-01, 17-18. SCE asserts that since there is no assurance of nonfirm energy, nonfirm energy provides no capacity savings to the purchasing utility even when nonfirm energy is provided during the purchasing utility's peakload hours. Only firm power provides capacity value. Hull, SCE, E-CE-01A, II-12-13; E-CE-03R, II-4-5.

PG&E contends that only up to 1,000 megawatts of thermal capacity was built to contribute to nonfirm energy, and only the costs of up to 200 megawatts of such capacity "could be fairly allocated to nonfirm rates." Kemp, PG&E, E-GA-02R; 8-10; Initial Brief, PG&E, B-GA-01, 7; Reply Brief, PG&E, R-GA-01, 5. PG&E disagrees with the Northwest Parties' inclusion of full capacity costs of all thermal resources in their Standard rate calculation. PG&E argues that "full capacity costs of operative thermal resources are the *maximum* amount of thermal capacity costs" that can possibly be included in the Standard rate. The actual allocation should be below this, and is determined by what thermal capacity would have been installed in the absence of BPA's nonfirm energy market. Kemp, PG&E, E-GA-02R, 6.

LADWP argues that including capacity costs in a nonfirm energy rate is unjustified because BPA does not incur capacity costs to supply nonfirm energy; if capacity is constrained, BPA does not offer nonfirm energy. Parmesano and Whitney, LADWP, E-LA-01, 16; Initial Brief, LADWP, B-LA-01, 3. CEC and CPUC also have concerns about the inclusion of capacity costs in nonfirm energy rates. Marcus, CEC, E-CC-01, 31; Enderby and Mattson, CPUC, E-CP-01, 26; E-CP-02R, 4.

The Northwest Parties dispute the California parties' arguments. BPA plans, operates, and incurs the cost of capacity to produce nonfirm energy. Mizer, NWP, E-NF-01, 4; E-NF-03R, 4.

**Evaluation of Positions**

Many of the California parties' arguments concerning capacity cost inclusion assume that the nonfirm energy rate should be based on marginal costs and that those marginal costs are the variable costs of hydro and on currently running thermal resources. However, these arguments fail to
[page 296] account for BPA’s long run generation and Intertie alternatives. From a system planning perspective. BPA can vary its resource mix to use a greater or lesser amount of nonfirm energy to serve firm loads. To the extent that a resource mix that uses a lesser amount of nonfirm energy is more expensive than an alternative, the additional expense is a long run marginal cost of supplying nonfirm energy. Even in the short run, nonfirm energy rates based solely on variable costs would not achieve the efficiency goals of marginal cost pricing because of the need to reflect the marginal cost to society in the form of shortage costs. Metcalf, BPA, E-BPA-64R, 4-5.

California parties argue that only costs incurred solely and specifically to provide nonfirm energy may be included in the nonfirm energy rate. They argue that the cost of a facility should not be included in the nonfirm energy rate unless one of its original purposes was to produce nonfirm energy. This argument overlooks the fact that the purpose and use of facilities change over time. Firm power and nonfirm energy are joint products of BPA's entire generation and transmission system, and it is appropriate to spread the cost of that system over both products. Metcalf, BPA, E-BPA-64R, 9-10. The full capacity of BPA's generation and transmission system contributes to the availability of nonfirm energy. Metcalf, BPA, E-BPA-37, 6.

These arguments were thoroughly evaluated by Judge Miller. See generally 29 FERC at 65,083-091. BPA's allocation of capacity costs to nonfirm energy comports with the Miller decision.

**Decision**

*BPA correctly allocates capacity costs to nonfirm energy because the capacity of the system is used to produce nonfirm energy. Basing the nonfirm energy rate solely or almost solely on variable costs would not be consistent with marginal cost pricing principles.*

**Issue #3**

*What is the proper amount of thermal capacity costs to be included in the target average revenue?*

**Summary of Positions**

BPA supports the capacity cost limitation advanced in the 7(k) Initial Decision. Metcalf, BPA, E-BPA-64R, 24-25. The Initial Decision states that BPA's cost of thermal generation capacity should be included up to the point that such capacity equals the average secondary energy available on BPA's system under average water conditions. 29 FERC at 65,093.

SCE argues that BPA incorrectly interprets and applies Judge Miller's capacity cost limitation. They argue that all thermal generating resources added by PNW utilities, as well as BPA, "must be considered in meeting the 3300 MW limitation adopted by the Initial Decision." Reply Brief, SCE, R-CE-01, 21. They argue that the PNW's baseload thermal generating capacity
[page 297] has exceeded the regional limit of 3300 MW since late 1975 and therefore only BPA's costs of Hanford and "possibly Trojan" may be included in the target average revenue calculation. Id.

The Northwest Parties disagree with the Initial Decision and BPA's adherence to the position advanced therein, concerning the thermal capacity cost limitation. Opatrny and Cook, NWP, E-NF-05SR, 4; Initial Brief, NWP, B-NF-01, 21-22; Reply Brief, NWP, R-NF-01, 17-19. NWP contends that "*every* addition of thermal resources to BPA's system preserves the system's ability to produce nonfirm energy." Opatrny and Cook, NWP, E-NF-05SR, 4. They further argue that BPA is inconsistent in allocating all conservation costs to the target average revenue calculation, but excluding some thermal capacity costs according to Judge Miller's limitation. Reply Brief, NWP, R-NF-01, 19.

**Evaluation of Positions**

Judge Miller used a 3300 aMW figure as the basis for determining properly includable thermal capacity costs. This figure approximates average nonfirm energy made available by total PNW hydro generation, rather than that made available by just BPA's system. Though Judge Miller's use of a regional figure was incorrect, the reasoning to his decision was logical.

The 3300 aMW limitation is provided by way of example in demonstrating his methodology. Contrary to SCE's argument, Judge Miller’s method depends on a determination of the average amount of nonfirm energy that is made available by BPA's hydro system. BPA's proposal properly compares this limitation to the energy capability of BPA’s operational and expected baseload thermal resources. Metcalf, BPA, E-BPA-64R, 24-25, All.

A key reason for including baseload thermal capacity costs in the nonfirm energy rate is that, on a planning basis, it would be possible to serve firm loads with nonfirm energy backed up with combustion turbines. Metcalf, BPA, E-BPA-64R, 4. Judge Miller reasoned that such a strategy could be used only up to the average availability of secondary energy. BPA's decision to limit these costs comports with that decision. NWP’s assertion that all thermal capacity costs should be included in the cost-based NF-85 rate is inconsistent with the Initial Decision. NWP also argues that if BPA includes all conservation costs in the target average revenue calculation, it is inconsistent not also to allocate all thermal capacity costs. They base this assertion on their belief that thermal resources and conservation resources both similarly increase the surplus and thus the availability of nonfirm energy. Reply Brief, NWP, R-NF-01, 19. Their assertion is incorrect. Thermal resources may be displaced with nonfirm energy. However, conservation is clearly not displaceable.

**<u>Decision</u>**

*Thermal capacity costs are included in the NF-85 rate up to the average availability of secondary energy. This is a reasonable estimate of the amount of baseload capacity that would not be needed if BPA employed a planning strategy of firming up nonfirm energy with combustion turbines.*

[page 298]

**<u>Issue #4</u>**

*Should conservation costs be included in the target average revenue?*

**<u>Summary of Positions</u>**

BPA includes conservation costs in the NF-85 rate schedule because conservation measures directly affect the availability of nonfirm energy. Conservation contributes to the availability of nonfirm energy because, in a time of firm surplus, more nonfirm energy is available than would be otherwise. Metcalf, BPA, E-BPA-37, 6-7.

SCE, PG&E, CPUC, and LADWP assert that the costs of BPA’s conservation programs should be excluded, since they make no contribution to the supply of nonfirm energy. Hull, SCE, E-CE-01A, III-18-19; Initial Brief, SCE, B-CE-01, 34; Reply Brief, SCE, R-CE-01, 25; Kemp, PG&E, E-GA-01, 5; Initial Brief, PG&E, B-GA-01, 7; Reply Brief, PG&E, R-GA-01, 5; Enderby and Mattson, CPUC, E-CP-01, 13; Initial Brief, CPUC, B-CP-01, 13; Parmesano and Whitney, LADWP, E-LA-01, 15; Initial Brief, LADWP, B-LA-01, 3.

SCE believes that conservation costs should be excluded from the nonfirm cost basis for three reasons: (1) conservation costs do not pay for themselves and represent a net cost to firm power customers, not nonregional nonfirm customers; (2) BPA’s conservation efforts would probably go unaltered even if it had no market for nonfirm energy; and (3) conservation by firm customers will slow firm load growth and delay the need for additional generating resources, and any ultimate reduction in costs will benefit firm rather than nonregional nonfirm customers. Hull, SCE, E-CE-01A, III-18. LADWP supports this argument and adds that if resources are avoided on a one-to-one basis with achieved conservation, a zero net impact on nonfirm energy availability should result. Parmesano and Whitney, LADWP, E-LA-01, 15.

PG&E concurs, stating, "conservation programs would not increase the amount of nonfirm energy available to BPA customers during firm surplus conditions, nor are they implemented to provide additional resources for the nonfirm market." Kemp, PG&E, E-GA-01, 5. CPUC argues that the conservation resource is acquired to meet firm loads and, if forecasted properly, should just meet firm load requirements. Enderby and Mattson, CPUC, E-CP-01, 26.

Conservation directly contributes to the availability of nonfirm energy, because it increases the size of the surplus. Metcalf, BPA, STR 820.

The performance of conservation programs and investments (which affect actual loads) determines how much water BPA must withdraw from reservoirs and how much BPA may keep in storage. In combination, these factors as well as stream flow levels determine whether actual reservoir levels exceed VECC. Mizer, NWP, E-NF-01, 10.

NWP also points to a contradiction in PG&E's position. While PG&E recognizes that the entire BPA system may contribute to the "production" of
[page 299] nonfirm energy, they also support excluding certain costs that make up a portion of the whole. Opatrny and Cook, NWP, STR 1458.

NWP agrees with the inclusion of conservation costs. Mizer, NWP, E-NF-03R, 10. Conservation resources contribute to the supply of nonfirm energy because (1) they are resources that cannot be displaced and hence preserve nonfirm energy for extraregional sales; (2) part of these resources is clearly presumed to be sold as nonfirm, and has been planned for accordingly; and (3) conservation resources are not subject to the vagaries of the weather but are available in all seasons. Id.

**Evaluation of Positions**

California utilities argue that conservation programs do not contribute to nonfirm energy supply. However, as NWP points out, the performance of conservation programs affects reservoir level in the same manner as generation resources. Mizer, NWP, E-NF-01, 10.

SCE argues that BPA's conservation effort would not be altered if BPA had no market for nonfirm energy. This argument ignores the basic facts of BPA's planning process. BPA uses the Least Cost Mix Model to plan new resource additions, including conservation. One of the four basic inputs to the model is "estimates of the marginal value of firm surplus energy. These estimates help define the net benefit (or loss) that results from acquiring more resources during a period of surplus." Fuqua, BPA, E-BPA-14, 19. Since BPA sells significant portions of its surplus firm power in the nonfirm energy market, that market directly affects BPA's resource planning during the surplus. Clearly, during the surplus, it is BPA's surplus firm power and nonfirm energy customers who most benefit from BPA's conservation program.

California parties argue that in the long run conservation will match load growth with no impact on nonfirm energy availability. However, if generating resources rather than conservation resources were used to meet load growth, nonfirm energy supply would be reduced because nonfirm energy could be used to displace generating resources. Clearly, conservation is not displaceable. Therefore, even in the long run, conservation increases nonfirm energy supply. It was this reasoning that lead Judge Miller to consider the possibility that the limit applied to thermal capacity costs should also be applied to conservation. 29 FERC ¶65,096. Allocation of conservation costs to nonfirm energy is nonetheless consistent with the Miller decision because of the short-term considerations discussed above. The Commission has previously recommended that portions of conservation costs be allocated to nonfirm energy. 23 FERC 61,342, 61,740 (1983).

**Decision**

*BPA correctly allocates conservation costs to nonfirm energy. The nonfirm energy market affects conservation planning, and conservation directly contributes to the availability of nonfirm energy.*

[page 300]

**Issue #5**

*Should fish and wildlife costs be included in the target average revenue?*

**Summary of Positions**

BPA includes fish and wildlife costs in the target average revenue. BPA, E-BPA-08, 119; Metcalf, BPA, E-BPA-64R, A10. The Northwest parties concur. Opatrny and Cook, NWP, E-NF-02S, 14; Mizer, NWP, E-NF-04R, 11.

LADWP disagrees with the inclusion of fish and wildlife costs on the grounds that these are capacity costs, which should not be included in the target average revenue. Parmesano and Whitney, LADWP, E-LA-01, 16. SCE also opposes including these costs. Hull, SCE, E-CE-01A, III-19.

PPC believes these costs should be included in all rates. Brawley, PPC, E-PP-02, 2. Since all customers benefit from the existence of the FCRPS, all customers should pay for its costs, and fish and wildlife costs are one of these costs. Brawley, PPC, STR 535.

**Evaluation of Positions**

The record fails to provide any persuasive arguments for the exclusion of fish and wildlife costs. LADWP's argument on capacity cost inclusion is discussed in Issue #2, above.

Judge Miller adopted the reasoning of BPA and the Northwest Parties that fish and wildlife costs were properly included in nonfirm energy rates. Because these are costs that are inextricably linked with the Federal dams, they are properly included in nonfirm energy rates. 29 FERC at 65,091.

**Decision**

*Fish and wildlife costs are correctly included in the NF-85 rate schedule, because all purchasers of energy from BPA's hydro system should share in these costs.*

**Issue #6**

*Should residential exchange costs be included in the target average revenue?*

**Summary of Positions**

BPA excluded residential exchange costs in its initially proposed NF-85 rate. These costs were added in rebuttal testimony in response to the 7(k) Initial Decision. Metcalf, BPA, E-BPA-64R, 24, A10.

All California parties claim that the resources acquired by BPA through the exchange program make no contribution to the supply of nonfirm energy.
[page 301] They argue generally that exchange costs should not be included for two reasons: (1) they were not incurred for the intended benefit of nonfirm customers; (2) BPA's exchange purchases and sales are off setting paper transactions, and are not intended to contribute to nonfirm energy availability in the NF-85 rate period. Hull, SCE, E-CE-01A, IV-2; E-CE-03R, IV-4; Initial Brief, SCE, B-CE-01, 32; Reply Brief, SCE, R-CE-01, 26; Kemp, PG&E, E-GA-01, 13; Kemp, PG&E, E-GA-02R, 6; Initial Brief, PG&E, B-GA-01, 7; Reply Brief, PG&E, R-GA-01, 5; Enderby and Mattson, CPUC, E-CP-01, 14; Initial Brief, CPUC, B-CE-01, 13; Parmesano and Whitney, LADWP, E-LA-01, 13, 18; Reply Brief, LADWP, R-LA-01, 2; Initial Brief, CEC, B-CC-01, 35-36; Reply Brief, CEC, B-CC-02, 19-22.

The Northwest Parties counter PG&E and SCE's position, asserting that the concurrent purchase and sale of residential exchange energy does have a direct Impact on the availability of nonfirm energy. Mizer, NWP, E-NF-03R, 11. If BPA did not concurrently purchase and sell residential exchange energy, BPA could serve the residential exchange load with one or a combination of sources. These sources include BPA's existing surplus firm power and nonfirm energy resources, and the "acquisition of resources other than a concurrent purchase under Section 5(c)." If BPA were to use these sources, less nonfirm energy would be available; therefore, nonfirm energy availability is directly affected by residential exchange purchases. *Id.*, 12. The cessation or reduction of §5(c) purchases would lessen the availability of nonfirm energy just as it would lessen the availability of firm power. Mizer, NWP, E-NF-01, 42.

**Evaluation of Positions**

The Northwest Parties' argument that the residential exchange contributes to nonfirm energy availability is not persuasive. The residential exchange is essentially a subsidy program that, at least currently, does not alter BPA's resources or loads. On the other hand, California party arguments that nonfirm energy customers should not share in paying this subsidy also are not persuasive.

There is supporting evidence in the record both for including residential exchange costs and for excluding these costs. However, these arguments were briefed thoroughly before and considered by Judge Miller. Judge Miller concluded that residential exchange costs were properly included in nonfirm energy rates because this cost, like all other operating costs, should be allocated to all those benefiting from the BPA system. 29 FERC at 65,094-095. Thus, while there is evidence in the record to support either position, BPA's proposal to include these costs comports with Judge Miller's decision. As discussed in Section 2 above, it is prudent to comport with Judge Miller's decision at this time.

[page 302]

**Decision**

*The allocation of residential exchange costs to nonfirm energy is proper because it is appropriate for nonfirm energy customers to share in paying the residential exchange subsidy.*

**Issue #7**

*Should the cost of industrial reserves be included in the target average revenue?*

**Summary of Positions**

The cost of industrial reserves was included in BPA's initially proposed standard rate. BPA, E-BPA-08, 68, 119; Metcalf, BPA, E-BPA-37, 7. This cost is excluded from the revised calculation of the target average revenue. Metcalf, BPA, E-BPA-64R, A10.

CPUC, PG&E, and LADWP disagree with BPA's inclusion of reserve costs in the NF-85 rate. They assert that any cost incurred solely to avoid interrupting firm load is inappropriate for nonfirm customers. They argue that no DSI first quartile service will be interrupted to serve nonfirm energy. Enderby and Mattson, CPUC, E-CP-01, 27; Initial Brief, CPUC, B-CP-01, 13; Kemp, PG&E, E-GA-01, 6; Initial Brief, PG&E, B-GA-01, 7; Reply Brief, PG&E, R-GA-01, 5; Parmesano and Whitney, LADWP, E-LA-01, 16; Initial Brief, LADWP, B-LA-01, 3. SCE notes that BPA does not maintain reserves for nonfirm energy sales, so nonfirm customers should not pay to ensure a firm load. Hull, SCE, E-CE-01A, III-20; Initial Brief, SCE, B-CE-01, 35.

APAC contends that reserve costs are related to providing nonfirm energy and therefore should be included in the Standard rate. Reply Brief, APAC, R-PA-01, 10.

**Evaluation of Positions**

Contrary to the California parties' arguments, DSI first quartile service may be interrupted to maintain sales of guaranteed delivery nonfirm energy. Griffin, BPA, STR 959. It is true that reserves are not maintained for nonfirm energy sales, but these reserves have made the construction of expensive generating resources unnecessary. The cost of such generating resources would be included in BPA's nonfirm energy rates. BPA, E-BPA-08, 335. On the other hand, the Initial Decision did not address the appropriateness of including the cost of reserves in

BPA's nonfirm energy rates. These costs are not reflected in BPA's rebuttal testimony, which implements that decision. The level of the NF-85 rates, based on costs specifically discussed in the Initial Decision, and excluding the cost of reserves, meets the objectives of an equitable sharing of benefits and equity with firm power rates.
[page 303]
**Decision**

*The cost of reserves is excluded from the target average revenue calculation. The cost of reserves might appropriately be included in the target average revenue calculation, but excluding these costs results in a rate level that satisfies the overall goals of sharing benefits and equity with firm customers. Further, because the cost of reserves was not addressed by Judge Miller, it is prudent to exclude these costs in this rate hearing.*

**Issue #8**

*Should the costs of a cash lag be included in the target average revenue?*

**Summary of Positions**

BPA includes cash lag in the target average revenue calculation. BPA, E-BPA-08, 119; Metcalf, BPA, E-BPA-64R, A10.

APAC argues that cash lag should be included in the target average revenue because it results primarily from quarterly billing of nonfirm energy sales to PSW utilities. Cook, APAC, E-PA-03, 6-7; Reply Brief, APAC, R-PA-01, 12. APAC argues that BPA should bill PSW utilities monthly or, if this is contractually prohibited, increase the PSW nonfirm energy rates to account for the cash lag. Id., 7. SCE counters the APAC argument by noting that the NF-85 Standard rate calculation already includes an amount for cash lag that should be "more than enough to compensate BPA for cash lag related to nonfirm sales." Hull, SCE, E-CE-03R, IV-9.

CPUC contends that cash lag might appropriately be included in a nonfirm energy rate, and suggests that these costs "might be figured as a percentage of BPA's costs." Enderby and Mattson, CPUC, E-CP-01, 27.

LADWP objects to including capacity costs in nonfirm energy rates, and therefore objects to including in the nonfirm energy rate the portion of cash lag costs that are allocated to capacity. Parmesano and Whitney, LADWP, E-LA-01, 16.

**Evaluation of Positions**

Cash lag reflects the delay between the time revenue is earned and the time cash payment is received. Cash lag may be caused by any number of customers or customer classes. PSW nonfirm energy customers contribute to BPA's cash lag. BPA, E-BPA-07A, F-18, Chapter 4; Roberts, BPA, STR 248. However, as discussed in Chapter III, relating cash lag to a specific customer class is not common utility practice. Therefore, it is appropriate to consider cash lag a part of BPA's total system cost and appropriately shared by nonfirm energy customers.
[page 304]

**Decision**

*The cost of cash lag is properly included in the target average revenue calculation because this cost is incurred to provide nonfirm energy.*

**Issue #9**

*What is the proper transmission component to assign to the NF-85 rate?*

**Summary of Positions**

BPA included the cost of its entire transmission system in the initially proposed NF-85 rate. The total transmission system is used to deliver nonfirm energy, whether to a Pacific Northwest customer or to the Intertie for sale to the PSW. The entire system serves both firm and nonfirm energy, even at times of peak use. Metcalf, BPA, E-BPA-37, 6.

The ICP recommends that the cost of the Pacific Southwest Intertie be included in the Standard rate only for extraregional sales. Wilson, ICP, E-IC-14, 2; Initial Brief, ICP, B-IC-01, 37.

SCE objects to including FCRTS costs that are related only to serving firm customers, fixed contract customers and capacity/energy exchange service, on the grounds that such costs are not incurred to serve nonfirm customers, whose service would be interrupted given a capacity constraint. Hull, SCE, E-CE-01A, III-21; Initial Brief, SCE, B-CE-01, 35; Reply Brief, SCE, R-CE-01, 27. CEC agrees with SCE, asserting that transmission costs of fringe and delivery are not rightly borne by nonfirm customers. Marcus, CEC, E-CC-01, 31; Initial Brief, CEC, B-CC-01, 2; Reply Brief, CEC, B-CC-02, 22.

CPUC argues that transmission costs related to "power rates and Capacity/Energy exchange" should not be included in the NF-85 rate. CPUC allows that transmission losses and a "reasonable" premium, based on 50 percent of average transmission fixed cost (without exchange transmission), should be included, as these are the only variable costs incurred due to nonfirm energy sales. Enderby and Mattson, CPUC, E-CP-01, 27.

**Evaluation of Positions**

Most of the California parties' positions follow from their arguments that only variable costs or costs of facilities constructed solely to provide nonfirm energy should be included in nonfirm energy rates. These arguments are addressed in Issue #2 of this section. The full capacity of BPA's transmission system is needed and used to deliver nonfirm energy.

The California parties and the ICP are correct that BPA's NF-85 proposal spreads the cost of the Fringe, Delivery, and Southern Intertie segments over all loads rather than attempting to assign those costs only to customers using these peripheral segments. Since BPA has decided to develop an NF-85 Intertie [page 305] adder, which spreads the cost of that segment only to users of that segment, it is appropriate to eliminate Fringe and Delivery costs from the rate. See Chapter IX, Section H on the the [sic] Intertie adder.

Further, BPA's inclusion of transmission costs in nonfirm energy rates comports with Judge Miller's decision. 29 FERC at 65,097.

**Decision**

*Transmission costs are included in the NF-85 target average revenue because the full capacity of BPA's transmission system is used to deliver nonfirm energy. Development of an intertie adder and exclusion of Fringe and Delivery costs from the target average revenue results in a more accurate allocation of those cost components.*

**Issue #10**

*How should High Cost Displacement rate sales be treated in the Standard rate calculation?*

**Summary of Positions**

BPA adjusts the NF-85 Standard rate upward to account for below-cost High Cost Displacement rate sales. Metcalf, BPA, E-BPA-64R, 26.

The Northwest Parties support BPA's method of accounting for below-cost High Cost Displacement rate sales. Opatrny and Cook, NWP, E-NF-02S, 14; E-NF-02SR, 12. They argue that if BPA wishes to make sales for displacement purposes and still use the Standard rate for other sales, the Standard rate must be increased if the total cost of producing nonfirm energy is to be recovered. *Id.*, E-NF-02S, 14.

SCE argues that there is no basis for a High Cost Displacement rate adder in the Standard rate calculation because there is no revenue deficiency associated with these sales. Hull, SCE, E-CE-03R, IV-7; Reply Brief, SCE, R-CE-01, 30. In addition, SCE objects to the High Cost Displacement rate adder because "the Standard rate becomes closely related to BPA's nonfirm forecasts which are very volatile and subject to change." Reply Brief, SCE, R-CE-01, 31.

**Evaluation of Positions**

BPA calculates the NF-85 Standard rate such that it will recover, on a forecasted basis, the fully allocated costs of producing nonfirm energy as well as the underrecovery from below-cost High Cost Displacement rate sales. Thus, the option of offering below-cost rates to respond to market conditions is preserved and the probability that target average revenues are recovered is enhanced. Metcalf, BPA, E-BPA-64R, 24.

[page 306]

SCE argues that there is no basis for a High Cost Displacement rate adder because there is no revenue deficiency associated with these sales, or with any nonfirm energy sales above BPA's incremental generation costs. SCE's argument is founded on the premise that BPA must base nonfirm energy rates on incremental cost. This argument concerning the proper cost basis for

BPA’s nonfirm energy is not supported by this record, as discussed in Section 1, above. Further, the issue was litigated extensively in recent 7(k) hearings on the NF-1 and NF-2 rates, and is not supported by the 7(k) Initial Decision.

SCE is correct that the Standard rate is directly affected by BPA’s forecasts of High Cost Displacement rate sales. As evidence that BPA's nonfirm energy forecasts are "very volatile and subject to change" they compare a forecast made for the initially proposed Nonfirm Energy rates with a forecast made for rates proposed in rebuttal testimony. This is an improper comparison. In the initial proposal, the Standard rate was lower than the subsequently proposed rate, and there was no High Cost Displacement rate. Further, BPA’s nonfirm energy forecasts can actually benefit purchasers of Standard rate energy. For example, if BPA forecast fewer High Cost Displacement rate sales relative to Standard rate sales than actually occur, the Standard rate will be lower than it would have been with an accurate forecast. Finally, SCE offers no alternative method to BPA's proposal.

**Decision**

*The NF-85 Standard rate is adjusted upward to account for revenue underrecovery from High Cost Displacement rate sales. This procedure properly shares the responsibility for below-cost Nonfirm Energy sales with purchasers of Standard rate energy, and comports with the 7(k) Initial Decision.*

**Issue #11**

*How should Low Cost Displacement rate sales be treated in the target average revenue and Standard rate calculations?*

**Summary of Positions**

BPA's initial proposal credited Fixed Displacement rate (Low Cost Displacement) revenues against cost, and excluded such sales from loads, in the average Standard rate calculation. BPA, E-BPA-08, 68-69; Metcalf, BPA, E-BPA-37, 5. In rebuttal testimony, the same procedure was used to calculate the target average revenue (the successor, methodologically, to the average Standard rate). Metcalf, BPA, E-BPA-64R, 25. BPA then calculates the Standard rate to recover the target average revenue plus, on a forecasted basis, the revenue underrecovery from High Cost Displacement rate sales. Revenue underrecovery resulting from Low Cost Displacement rate sales is not considered in the Standard rate calculation. *Id*., 23-25.

The CPUC contends that the Fixed Displacement rate should be eliminated, but if it is not eliminated, resulting revenues should be ignored in the
[page 307] average Standard rate numerator, and the sales should be added to the denominator. Enderby and Mattson, CPUC, E-CP-01, 28.

LADWP claims that the Standard rate should not be designed to recover the underrecovery from Low Cost Displacement rate sales. The result, they claim, would be California utilities subsidizing the PNW because California is projected to buy the majority of Standard rate energy while the PNW is projected to buy all Low Cost Displacement energy. Initial Brief, LADWP, B-LA-01, 6.

The Northwest Parties contend that the Low Cost Displacement rate revenue credit should not occur in the target average revenue calculation. Opatrny and Cook, NWP, E-NF-05SR, 5. NWP includes in the target average revenue denominator all Federal secondary energy capability referenced in BPA's rebuttal testimony (E-BPA-64R, 25, All). *Id*., 6. Thus, the target average revenue denominator includes Low Cost Displacement rate sales as well as an undetermined amount of unsold nonfirm energy. NWP then advocates a Standard rate that recovers all underrecoveries of below-cost NF-85 sales, including sales made at the Low Cost Displacement rate. Opatrny and Cook, NWP, E-NF-02, 20-21; E-NF-02S, 14-15; E-NF-05SR, 1, 6; Initial Brief, NWP, B-NF-01, 21-22; Reply Brief, NWP, R-NF-01, 19-22. APAC agrees that the Low Cost Displacement rate revenue underrecovery should be recovered, though they do not suggest a specific remedy. Reply Brief, APAC, R-PA-01, 9.

PG&E, SCE, and CPUC contend that the Northwest Parties' proposed underrecovery adder would be a cross-subsidy within the nonfirm energy class, providing the PNW with all the Low Cost Displacement energy while charging the PSW for the underrecovery. Kemp, PG&E, E-GA-02R, 5; Hull, SCE, E-CE-03R, IV-6-7; Initial Brief, SCE, B-CE-01, 41; Initial Brief, CEC, B-CC-01, 40-41; Reply Brief, CEC, B-CC-02, 22-23.

**<u>Evaluation of Positions</u>**

The initial impact of the Northwest Parties' proposal is on the target average revenue calculation. By not crediting Low Cost Displacement rate revenue, the numerator is increased, but relatively less than the increase to the denominator that results from the addition of Low Cost Displacement rate sales (as well as unsold nonfirm energy). The result achieves a lower target average revenue than does BPA's proposal. The next impact of NWP's proposal is on the Standard rate calculation. The effect of their proposal is opposite to, and far outweighs, their proposal discussed above. Their recommendation to factor the underrecovery from Low Cost Displacement rate sales into the Standard rate calculation raises this rate to 27.44 mills per kilowatt-hour. Opatrny and Cook, NWP, E-NF-05SR, 6-7, Attachment C. They admit that this rate is "too high," and could be reduced by eliminating the High Cost Displacement rate. *Id*., 7. They then assume that all High Cost Displacement rate sales could be marketed at the nonguaranteed Standard rate and, if this were to occur, the Standard rate would be reduced to 25.55 mills per kilowatt-hour. *Id*., 9. The NWP proposal places the entire burden of the Low Cost Displacement rate underrecovery on purchasers of Standard rate energy. Metcalf, BPA, STR 807.
[page 308]
On the other hand, the CPUC proposal would calculate the Standard rate as if the Low Cost Displacement rate sales were being made at the Standard rate. The firm power customer would be assigned the full cost of the underrecovery.

BPA proposes to exclude Low Cost Displacement rate sales from the revenue underrecovery adjustment to the Standard rate so as not to raise disproportionately the Standard rate. This methodology shares the benefits of these sales between firm and nonfirm energy purchasers. Metcalf, BPA, E-BPA-64R, 25.

The Northwest Parties contend that BPA's treatment of Low Cost Displacement rate sales and revenue does not comport with the 7(k) Initial Decision because it "assures an underrecovery of average costs." Opatrny and Cook, NWP, E-NF-05R, 6. A review of the 7(k) Initial Decision, however, does not support the Northwest Parties' contention that BPA *must* recover the average cost of providing nonfirm energy. The Initial Decision notes that "[o]ne justification that could exist [for nonfirm energy sales below cost] is that BPA could not have sold the nonfirm energy unless it sold at a loss. Obviously any notions of fair allocations can be overridden by the market place. The rates must be set at levels that will be exercised by purchasers." 29 FERC at 65,112. The Initial Decision also notes that "there was no excuse for BPA not designing its nonfirm rates so as to recover the costs *fairly* allocated to nonfirm energy from nonfirm energy users" (emphasis added). 29 FERC at 65,113. These suggest that below-cost nonfirm energy rates may be appropriate in certain market conditions, and that fairness in cost allocation is an important consideration. Sales of Low Cost Displacement rate energy are the lowest priority nonfirm energy sales. Though below cost, sales at this rate bring revenues to BPA that might not otherwise be attainable. Metcalf, BPA, E-BPA-64R, 25. If these sales are factored into the Standard rate calculation, then purchasers of Standard rate energy, primarily California utilities, will bear the full burden of a compensating overrecovery resulting from sales forecast to be made exclusively to PNW utilities. Metcalf, BPA, STR 807; Kemp, PG&E, E-GA-02R, 5; Hull, SCE, E-CE-03R, IV-6-7; Initial Brief, SCE, B-CE-01, 41; Initial Brief, CEC, B-CC-01, 40-41; Reply Brief, CEC, B-CC-02, 22-23.

**Decision**

*Low Cost Displacement rate revenues are a credit to cost, and such sales are excluded from loads, in the target average revenue calculation. The Standard rate is not adjusted upward to account for revenue underrecovery from Low Cost Displacement rate sales. These procedures share the benefits of Low Cost Displacement rate sales between Standard rate purchasers and firm power customers, and maintain the Standard rate at a level that is equitable in relation to firm power rates.*

**Issue #12**

*Should the revenue deficiency resulting from sales of surplus firm power at NF-85 rates be allocated to the cost based nonfirm energy rate?*

[page 309]

**Summary of Positions**

In the initial proposal, BPA allocated the revenue deficiency resulting from surplus firm power sold as nonfirm energy to firm classes of service. BPA, E-BPA-08, 38-39; Peters, BPA, E-BPA-33, 12.

The Northwest Parties contend that "It is appropriate to include in the NF-85 rate the cost of surplus firm energy which is sold as nonfirm energy." Opatrny and Cook, NWP, E-NF-02, 7. They propose that the fully allocated cost of producing nonfirm energy be increased to recover revenue losses resulting from surplus firm power sold below-cost at NF-85 rates. Id., 7-8; E-NF-02S, Schedule 6. Subsequent testimony by the Northwest parties failed to address such an adder, and the adder was omitted from a recommended Standard rate calculation. Opatrny and Cook, NWP, E-NF-05SR, 12.

**Evaluation of Positions**

The Northwest Parties claim that it is "appropriate" to include the surplus firm power revenue deficiency in the NF-85 rate because "[p]urchasers of economy energy benefit from the availability of surplus firm energy not sold at the appropriate rate but, rather, sold at economy energy rates." Opatrny and Cook, NWP, E-NF-02, 7. However, the target average revenue calculation includes all costs allocated to surplus firm power, including exchange costs. NWP's recommendation would place the full burden of the revenue deficiency on NF-85 purchasers, yet the revenues from such sales would benefit the firm power customers. Such an allocation would appreciably raise the NF-85 Standard rate, and could adversely affect sales.

**Decision**

*The surplus firm power revenue deficiency is allocated to firm classes of service. No special allocation of these costs to nonfirm energy customers is appropriate because all costs allocated to surplus firm power are included in the target average revenue calculation.*

**Issue #13**

*Should the NF-85 Standard rate be seasonally differentiated?*

**Summary of Positions**

BPA's proposed NF-85 rate is not seasonally differentiated.

LADWP and PG&E contend that the NF-85 Standard rate should be seasonally differentiated. Parmesano and Whitney, LADWP, E-LA-01, 17; Kemp, PG&E, E-GA-01, 3.
[page 310]
**Evaluation of Positions**

PG&E recommends a cost-based, seasonally differentiated nonfirm rate to reflect the costs of all resources contributing to the seasonal availability of nonfirm energy. Kemp, PG&E, E-GA-01, 3. PG&E develops ceiling rates for two different operational conditions: spill or imminent spill, and nonspill. *Id*., E-GA-01S, Attachments 1 and 2. PG&E does not, however, develop seasonally differentiated rates for these periods, or suggest how such rates should be developed. It is difficult to evaluate PG&E’s proposal with the information provided. BPA's proposed seasonally differentiated rate schedules identify the summer energy billing months as April through August. This season is a result of an analysis of both loads and resources. Spill or imminent spill conditions frequently occur during the January through March period.

LADWP contends that "[a]ll of BPA’s studies indicate that nonfirm energy is less expensive to supply in the spring and summer than in the winter," as BPA's previous use of a spill rate shows. Parmesano and Whitney, LADWP, E-LA-01, 17. LADWP is incorrect. BPA's cost of service studies do not address the cost of generating nonfirm energy. Prior nonfirm energy spill rates have been designed to respond to market conditions, not to cost of service. The 1983 Administrator's Record of Decision retained the NF-83 Spill rate because without the Spill rate "there may be significant levels of Pacific Northwest thermal generation that would not be displaced." BPA, 1983 Rates ROD, 310.

LADWP also argues for seasonal differentiation because "the costs used in the [Standard rate] calculation are already seasonally differentiated in BPA's RAM, COSA and WPRDS." Parmesano and Whitney, LADWP, E-LA-01, 17. This argument is not persuasive. The costs referenced by LADWP are assigned to seasonal energy periods on the basis of firm energy produced by the FBS. BPA, E-BPA-01, 21-22. BPA's seasonal differentiation is designed to send the proper price signal to PNW customers, and is based in part on PNW loads. Such price signals are inappropriate for the nonfirm energy rate because most nonfirm energy is sold to California, where cost and load patterns are different. In addition, BPA must be concerned with the effect of rates on marketability of power to California. As with the Surplus Firm Power rate, seasonally differentiating the nonfirm energy rate along the lines of BPA's firm power rates would place greater costs into periods when demand is lowest.

**Decision**

*The Standard rate is not seasonally differentiated because the firm power seasonal price signals are inappropriate for nonfirm energy customers. Such price signals would also detract from BPA's ability to recover its target average revenue from nonfirm energy customers.*

**Issue #14**

*Should BPA retain the 7.0 and 3.0 mills per kilowatt-hour Low Cost Displacement rate?*
[page 311]
**Summary of Positions**

The Low Cost Displacement rate (in the initial proposal, the Fixed Displacement rate) helps ensure that the NF-85 rate schedule responds to market conditions and displaces the greatest possible amount of thermal generation or end-user loads with an alternative fuel source. BPA, E-BPA-08, 70; Metcalf, BPA, STR 560.

PG&E and CPUC assert that the NF-85 Low Cost Displacement rate should be eliminated. Kemp, PG&E, E-GA-01, 9; Enderby and Mattson, CPUC, E-CP-01, 28.

The Northwest Gas Utilities argue that the 7 mill per kilowatt-hour Low Cost Displacement rate is inconsistent with BPA's asserted purpose to serve the highest value nonfirm energy markets. Conkling, AWGU, E-WG-07SR, 16-18.

PSP&L states that the 7.0 mill rate "will not necessarily" displace some PNW coal-fired generation. BPA should offer a nonfirm energy rate that will displace all PNW thermal generation during spill conditions. Initial Brief, PSP&L, B-PS-01, 4; Reply Brief, PSP&L, R-PS-01, 8-9. On the other hand, WPAG recommends raising the rate for coal-fired resources to 9 mills per kilowatt-hour because "this rate would displace all of the coal fired generation identified as displaceable by BPA in the documentation to the WPRDS."  Hutchison et al., WPAG, E-WA-01, 63; Reply Brief, WPAG, R-MA-01, 29-30.

**Evaluation of Positions**

PG&E asserts that the Low Cost Displacement rate should be eliminated because it (1) is based on value and not cost of service, (2) discriminates against California utilities because "BPA projects no displacement rate sales to nonregional customers," and (3) is administratively in feasible.  Kemp, PG&E, E-GA-01, 9-10.  None of these arguments is persuasive.  It is appropriate for BPA to design nonfirm energy rates based on criteria other than cost of service.  See Section 2 for a detailed discussion of this Issue.  PG&E is correct that no Low Cost Displacement rate sales are projected to be made to California utilities.  No sales are projected to California utilities due to in sufficient cost information.  Roghair, BPA, STR 839.  Further, limited transfer capability of the Pacific Southwest Intertie may preclude such sales.  Griffin, BPA, S'TR 968.  As support for their argument that the rate is administratively in feasible, PG&E contends that "[t]he provisions of the Exportable Agreement make it difficult for BPA to offer displacement rate energy for export."  The Exportable Agreement, however, is not the only constraint to BPA's ability to offer Low Cost Displacement rate energy to the Pacific Southwest.  A more apparent constraint is limited Pacific Southwest Intertie transfer capability.  Griffin, BPA, STR 968.

The Northwest Gas Utilities note that BPA's objective in proposing the Low Cost Displacement rate seems to be inconsistent with a BPA argument advanced in the section 7(k) hearing on the NF-1 and NF-2 rates.  This argument, quoted by NGU from the 7(k) Initial Decision, is that low nonfirm energy rates
[page 312] "prevent the highest economic use of the nonfirm product: displacement of high decremental cost oil- and gas-fired generation in California" and, further, "to price the nonfirm energy too low undermines the stability of the firm power resource."  Conkling, NGU, E-WG-07SR, 17.  NGU also "cannot square" the Low Cost Displacement rate with the economic rationing function which BPA claims nonfirm energy rates fail to perform if they are too low.  Id., 17-18.

All NGU citations refer to *average* nonfirm energy rates.  The Low Cost Displacement rate is not an average rate, but rather a market expansion rate.  This rate requires that resources actually be shut down or backed off, thus ensuring that displacement actually will occur.  Metcalf, BPA, E-BPA-37, 17.  Low Cost Displacement rate energy will be offered only after all markets have been satisfied at the higher NF-85 rates.  Thus, the Low Cost Displacement rates will not reduce the displacement of high incremental cost resources, regardless of location.  This 7 and 3 mills per kilowatt-hour energy will be made available if it "achieves a combined result of further utilization of transfer capability and increased revenues."  Griffin, BPA, E-BPA-65R, 4.

If the Low Cost Displacement rate were raised to 9 mills per kilowatt-hour as WPAG recommends, the rate would be only 0.27 mills lower than BPA's 1986 forecast of total variable cost for Colstrip 1 and 2.  BPA, E-BPA-08A, 80.

WPAG contends that variable transmission costs should be included in the forecast of total variable cost for Colstrip 1 and 2 and, if such costs are included, the level of projected Colstrip 1 and 2 variable costs will be "more than a sufficient incentive for Colstrip owners to displace this resource" at a 9 mill rate. Reply Brief, WPAG, R-WA-01, 29-30. WPAG's adjustment is correct only to the extent that Colstrip owners sign IR transmission agreements, rather than keeping their FPT agreement. The FPT rate is based solely on contract demand and has no component that varies with energy use. Many of WPAG's concerns should be alleviated by the adoption of the High Cost Displacement rate. As a result, only resources with decremental cost less than 14.8 (16.0 in the PSW) have access to the Low Cost Displacement rate.

PSP&L asserts that the 7.0 mill rate is too high to displace Colstrip 1 and 2. No documentation is provided for this assertion and even if true, would not necessarily lead to a conclusion that the rate should be lowered. The goal of displacing resources is important, but other considerations such as revenues also must be considered. Metcalf, BPA, STR 644.

**Decision**

*The Low Cost Displacement rate is included in the NF-85 rate schedule. The 7 mill rate is properly set to displace most, and possibly all, PNW coal-fired resources.*

### 4. Share-the-Savings Rate

**Issue #1**

*What is the proper structure of a Share-the-Savings rate?*
[page 313]
**Summary of Positions**

BPA initially proposed a Variable Displacement rate based on share-the-savings principles as part of the NF-85 rate schedule. The Variable Displacement rate was to be offered below the Standard rate and was based on 75 percent of the buyer's decremental cost. To be eligible for this rate, the purchaser's decremental cost was to be less than the Standard rate plus 2.0 mills per kilowatt-hour. Metcalf, BPA, E-BPA-37, 4-14. The Evaluation of the Record retains the NF-85 Variable Displacement rate and proposes a separate experimental Nonfirm Energy rate schedule based entirely on share-the-savings principles. Evaluation, BPA, A-01, 172-175. This schedule, the SS-85 Share-the-Savings rate, has two rate components with the rate for each a function of the purchaser's decremental cost. The Economy Energy rate applies to purchasers with decremental costs equal to or greater than the NF-85 Standard rate (plus the Intertie adder for a PSW utility). The rate is calculated as 50 percent of decremental cost, plus 6.0 mills per kilowatt-hour. The second SS-85 rate, the Displacement rate, applies to purchasers with decremental costs less than the NF-85 Standard rate. This rate is calculated as the greater of (1) 75 percent of decremental cost, or (2) 11.0 mills per kilowatt-hour. Displacement of a qualifying resource, purchase alternative, or end-user alternate fuel source is not required for Economy Energy rate service. Displacement is required for SS-85 Displacement rate service.

The Northwest Parties claim that BPA’s initial proposal contains the flaw of downward-only pricing flexibility, which ensures underrecovery of the costs of producing nonfirm energy. As a solution, NWP recommends rates that are based solely on share-the-savings principles. NWP's proposed rates have both upward and downward flexibility, to permit some sales at above-cost rates and some at lower rates. NWP proposes that separate rates be established for economy energy and for displacement energy. The economy energy rate would be based on 75 percent of the decremental cost of a prequalified resource, with a rate floor at a properly computed Standard rate. The prequalified resource would not be required to shut down. If the economy energy market is saturated, the displacement energy rate would be offered, subject to a revenue test. The displacement energy rate would also be based on 75 percent of decremental cost, but would require physical displacement of the prequalified resource. Opatrny and Cook, NWP, E-NF-02, 12-13, 20-21; Initial Brief, NWP, B-NF-01, 5-6.

The Northwest Gas Utilities claim that BPA pays only lip service to a Share-the-Savings rate. NGU believes that BPA could calculate its incremental cost and could therefore implement a "legitimate" Share-the-Savings rate based on both incremental and decremental costs. Conkling, NGU, E-WG-07SR, 4-13. In subsequent testimony, NGU recommends a Share-the-Savings rate based on 75 percent of decremental cost, with no rate floor. Reply Brief, NGU, R-WG-01, 12-1 3.

PG&E contends a Share-the-Savings rate based on 75 percent of the purchaser's decremental cost is in equitable because the benefits are strongly
[page 314] in BPA's favor. Kemp, PG&E, E-GA-02R, 2. PG&E contends that such a Share-the-Savings rate will create a cross-subsidy both within the nonfirm energy class and between nonfirm energy customers and firm power customers. *Id*. 1-2; E-GA-03SR, 3.

The CEC contends that if a Share-the-Savings rate component is a part of the NF-85 rate schedule, BPA should offer share-the-savings energy "to both regions at the same price and then work its way down rather than giving the Northwest first chance at all of the energy." Marcus, CEC, E-CC-01, 36. CEC contends that the Northwest Parties' proposal that displacement not be required for economy energy purchases will lead to arbitrage of BPA energy. Reply Brief, CEC, B-CC-02, 15-16.

The ICP expresses concern that a "properly structured Share-the-Savings rate [have] iron-clad and bullet proof guarantees that neither its structure nor sales made thereunder violated the intent and purpose of PL 88-552." Wilson, ICP, E-IC-14, 3.

**<u>Evaluation of Positions</u>**

The parties' positions address four basic issues. These issues are: (1) basing the NF-85 rate solely on share-the-savings; (2) upward and downward flexibility; (3) the appropriate pricing formula to meet the goals of cost recovery, ease of administration, and sharing of benefits; and (4) consistency with regional preference. The first issue is discussed in Section 1.

The NWP proposal for upwardly flexible rates has merit. The Northwest Parties are correct that the initially proposed NF-85 rate schedule would result in unit nonfirm energy revenues that fall below the unit cost of supplying the energy. BPA's proposal advanced in rebuttal testimony sets the Standard rate above unit cost to compensate for some below-cost nonfirm energy sales and thus in part addresses the issue of cost underrecovery raised by the NWP. Metcalf, BPA, E-BPA-64R, 23. A Share-the-Savings rate could also address concerns of California utilities that BPA's cost-based rates may result in inadequate benefits to California utilities if fuel prices continue to decline. Initial Brief, CEC, B-CC-01, 7-9; Reply Brief, CEC, B-CC-02, 5-8.

BPA, NWP, and NGU all propose share-the-savings rates based on 75 percent of decremental costs. CEC and PG&E criticize these proposals for not providing adequate benefits to the purchaser. This criticism has merit. A rate based on 75 percent of decremental cost is reasonable for a Share-the-Savings rate like that initially proposed by BPA, which is below cost only. However, a rate based on 75 percent of decremental cost may be inappropriate as the calculated rate approaches or exceeds the target average revenue;. In this situation, a greater share of the benefits should go to the purchaser.

NGU provides no support for its assertion that BPA could design a Share-the-Savings rate based partly on its incremental cost. Incremental cost is difficult to define on a mixed hydro and thermal system because it is
[page 315] difficult to associate specific resources with the generation of nonfirm energy. Metcalf, BPA, E-BPA-37, 12.

The ICP argues that BPA's proposed SS-85 rate should be implemented consistent with PL 88-552. In the Evaluation of the Record, BPA outlines implementation of the NF-85 and SS-85 rates. Evaluation, BPA, A-01, 174-175. BPA will offer the NF-85 Standard rate and the SS-85 Economy Energy rate in preference order. Normally, when markets are satisfied at these rates the NF-85 High Cost Displacement rate and the SS-85 Displacement rate will then be offered in preference order.

**Decision**

*BPA is adopting the experimental SS-85 Share-the-Savings rate as an alternative to the NF-85 rate. SS-85 has two components similar to those proposed by the NWP. A purchaser whose decremental costs are greater than or equal to 24.0 mills per kilowatt-hour may purchase at the Economy Energy rate. The pricing formula is one-half of the purchaser's decremental cost, plus 6.0 mills per kilowatt-hour. The Displacement rate applies to purchasers with decremental costs less than 24.0 mills per kilowatt-hour. The pricing formula is the greater of 75 percent of decremental cost or 11.0 mills per kilowatt-hour.*

*This formula is a continous [sic] function that provides an equitable sharing of benefits at all levels of decremental cost.*

**Issue #2**

*To what extent can a purchaser qualify for the NF-85 displacement rates by displacing alternative purchases?*

**Summary of Positions**

BPA proposes that a confirmed purchase of energy can contribute to a utility's decremental cost, but only if the prospective purchaser of NF-85 energy is able to shut down or back down the resource that would have generated the alternative purchase. BPA, E-BPA-08, 69; Griffin, BPA, STR 1074.

The Northwest Parties support "verifiable resource displacement" for share-the-savings sales. Presumably, this verifiable displacement could include the generating facility behind a purchase alternative. Opatrny and Cook, NWP, E-NF-05SR, 8.

CEC, SCE, and LADWP recommend that a purchaser's decremental cost be allowed to be based on an alternative purchase of economy energy, without shutdown of the alternative resource. They argue that California utilities do not have the control over other utilities' resources that is necessary to meet the shutdown requirement. Marcus, CEC, E-CC-01, 34-36; E-CC-02R, 10; Initial Brief, CEC, B-CC-01, 18-20; Reply Brief, CEC, B-CC-02, 17; Hull, SCE, E-CE-03R, III-5-6; Reply Brief, LADWP, R-LA-01, 6-7.
[page 316]

**Evaluation of Positions**

BPA's NF-85 High Cost Displacement rate will at times be implemented as a market expansion device. Griffin, BPA, STR 949. The reason for the shutdown rule if decremental cost is to be based on a purchase alternative is to maintain a constant level of supply on the purchasing utility's system or in that utility's market area. *Id*. If a constant level of supply were not maintained, the purchase alternative might just "ricochet" to another utility in BPA's market area and lower BPA's revenues. *Id*., STR, 951, 1074.

The Northwest Parties' concern that "phantom resources" might drive down rates is warranted only if the generating resources behind purchase alternatives are not required to be shut down or displaced.

CEC argues that "economy energy resources must be eligible for some type of displacement rate… in order to prevent erosion of BPA's markets and revenues." Initial Brief, CEC, B-CC-01, 20. They contend that if economy energy purchases are not counted in decremental cost calculations, BPA's rate in many circumstances will be too high. BPA's position is just the opposite, that market and revenue erosion will occur without the displacement rule.

Clearly, the question of competing with alternative purchases is a major unresolved issue in implementing a Share-the-Savings rate. A strict shutdown rule as proposed by BPA, or a prohibition against basing decremental cost on purchase alternatives as proposed by NWP, could severely limit BPA's ability to market nonfirm energy in California during minimum load conditions. On the other hand, allowing unfettered use of alternative purchases creates the possibility of a single prospective purchase ricocheting and lowering BPA cost recovery. The High Cost Displacement rate was proposed by BPA partially to cope with this problem.

**Decision**

*In the NF-85 Nonfirm Energy rate, a confirmed purchase alternative will be considered in decremental cost calculations if the generating resource behind the alternative purchase is shut* *down or backed down in an amount equal to the amount of the NF-85 purchase. This displacement rule may on occasion preclude sales to California utilities who do not have control over other utilities' resources. Such a rule will enhance revenues, however, by maintaining total nonfirm energy supply and revenue in BPA's market area.*

*Provisions for displacing purchases in the alternative SS-85 Share-the-Savings rate will be determined contractually.*

**5. Guaranteed Delivery**

**Issue #1**

*Should BPA continue to offer guarantee provisions with its nonfirm energy rate schedules?*
[page 317]

**Summary of Positions**

BPA proposes to offer guaranteed delivery NF-85 energy, with a surcharge of 2.0 mills per kilowatt-hour (the initially proposed surcharge was 3.4 mills per kilowatt-hour). Metcalf, BPA, E-BPA-37, 7; E-BPA-64R, 29. The guarantee is normally for a 3- or 4-day period. BPA, E-BPA-08, 71; Griffin, BPA, E-BPA-38S, 1; Metcalf, BPA, E-BPA-64R, Attachment A13, 10. BPA's experience with implementation of the NF-83 rate schedule provisions for guaranteed delivery does not indicate a need for major change. The guaranteed time period is long enough to be effective in displacing additional thermal resources. Griffin, BPA, E-BPA-38, 8.

PG&E states that it will purchase little if any guaranteed nonfirm energy at a 3.4 mill surcharge, and would not be willing to pay a higher surcharge in return for a longer guarantee. Kemp, PG&E, E-GA-01, 11-12.

SCE argues that BPA would interrupt guaranteed nonfirm energy deliveries before buying power elsewhere or before using its spinning reserves, so there really is no guarantee at all. Unless the guarantee becomes a greater commitment on BPA's part they will discontinue purchases of guaranteed nonfirm energy. Initial Brief, SCE, B-CE-01, 39-40; Reply Brief, SCE, R-CE-01, 37-38.

The CEC supports guarantee provisions, noting that with guarantees utilities can avoid a portion of costs for no-load, minimum load, and start-up fuel. Marcus, CEC, E-CC-01, 17.

The Northwest Parties contend that a guaranteed delivery surcharge of 2.0 mills per kilowatt-hour is inappropriate for the SS-85 rate schedule. They suggest that SS-85 purchasers could be compensated for their inability to purchase guaranteed nonfirm energy by serving them ahead of NF-85 customers, with the same decremental costs. Reply Brief, NWP, R-NF-01, 22-23.

**Evaluation of Positions**

BPA guaranteed nonfirm energy sales in FY 1984 were roughly 15 percent of Standard rate sales to California. Roghair, BPA, STR 831-832. That is, PSW customers chose to pay a surcharge on those sales to improve their quality of service. Since California utilities purchased measurable amounts of guaranteed BPA nonfirm energy in FY 1984 under the NF-83 rate, and since the NF-85 provisions are not significantly different, BPA concludes that there is a value to BPA's customers in providing the guarantee.

PG&E's assertions may mean that PG&E places a value on the guarantee that is less than 3.4 mills per kilowatt-hour. BPA, in fact, proposes to lower the guarantee charge to 2.0 mills per kilowatt-hour, which is close to PG&E's calculated rate of 1.6 mills per kilowatt-hour.

SCE argues that the guarantee is of no value because BPA would not restrict DSI first quartile service before restricting guaranteed nonfirm energy deliveries. BPA might, however, interrupt first quartile service to
[page 318] the DSIs in order to make delivery of guaranteed NF-85 energy. Griffin, BPA, STR 958-959. However, such a conflict between these two nonfirm energy deliveries is an "unlikely event". Griffin, BPA, STR 959. Such an event is unlikely for two reasons. First, several actions are available to BPA before reaching a choice between first quartile service and guaranteed nonfirm energy delivery. These include, among others, purchase of energy, recall of storage, emergency assistance from other utilities, and advance load factoring service. Second, if all these actions had been taken and a conflict still remained between guaranteed nonfirm and first quartile service, it is likely that a general emergency had occurred, of such a magnitude that the protection of firm load in the Northwest would be the first priority, and *all* nonfirm deliveries would be immediately ceased. As the issue of the value of guaranteed nonfirm energy is fundamentally factual (i.e., operational), there is no need to address the legal issues raised by SCE. In addition, BPA retains the language from the NF-83 rate schedule that states that forced outages may cause reduced deliveries of nonfirm energy. This language merely reiterates an obligation of BPA to firm power customers, some of whose deliveries, though firm, may also be restricted for forced outages (i.e., certain DSI deliveries).

The CEC position supports BPA's position that there is value received by customers that purchase energy under the guarantee provisions.

**Decision**

*The evidence indicates that BPA's nonfirm energy customers receive a value from purchasing energy under the Nonfirm Energy guarantee provisions. Restriction of guaranteed nonfirm energy deliveries is an extremely unlikely event, given the conservative planning and operating assumptions that BPA regularly uses. BPA will continue to offer the guarantee provision in the NF-85 rate schedule. Guarantee provisions in the SS-85 rate schedule will be handled in the SS-85 contract.*

**Issue #2**

*How should the guaranteed delivery surcharge be determined?*

**Summary of Positions**

BPA's initial proposal based the nonfirm energy guaranteed delivery charge on thermal capacity costs. Metcalf, BPA, E-BPA-37, 7. The charge was derived by dividing total thermal capacity costs by the sum of loads used in the average Standard rate calculation. *Id*. The guaranteed delivery charge is retained in BPA's revised proposal, but the charge is lowered from 3.4 to 2.0 mills per kilowatt-hour. Also, the charge no longer is based on cost as in the initial proposal; rather, the charge is set to approximate the guaranteed delivery charge for the NF-83 rate schedule. Metcalf, BPA, E-BPA-64R, 29-30.

The Northwest Parties contend that basing the guaranteed delivery surcharge on thermal capacity costs and excluding these costs from the
[page 319] Standard rate calculation will result in an underrecovery of such costs. Opatrny and Cook, NWP, E-NF-02, 7.

The CPUC recommends a guaranteed delivery charge "to reflect the slightly higher priority of guaranteed nonfirm energy over nonguaranteed nonfirm energy." This "premium" should be 1.5 mills per kilowatt-hour based on one-half of hydro and thermal capacity costs (excluding WNP-1 and -3). Enderby and Mattson, CPUC, E-CP-01, 33.

PG&E recommends a charge of 0.5 mills per kilowatt-hour for guaranteed delivery during spill conditions, reflecting "BPA's zero costs plus a small incentive." Outside of spill conditions, the charge should be based on "operative BPA thermal capacity costs" and would be between 0.5 and 1.6 mills per kilowatt-hour. Kemp, PG&E, E-GA-01, 11; E-GA-01S, 2; Reply Brief, PG&E, R-GA-01, 4.

LADWP believes that "the proposed guarantee adder [of 3.4 mills per kilowatt-hour] exceeds the cost of providing a 4-day guarantee." They propose that BPA's LCMM or SAM models be used to quantify the costs of guaranteed delivery. Parmesano and Whitney, LADWP, E-LA-01, 12, 20-21.

SCE claims that, "[i]n making the guarantee, BPA assumes a risk that it may have to replace the guaranteed energy at a higher cost [and] the surcharge should be related to the probability of having to make this replacement and the cost of this replacement energy. It is unlikely that this risk is as high as 3.4 mills per kwh." Hull, SCE, E-CE-01A, III-14. They further assert that BPA's level of risk does not justify a 2.0 mills per kilowatt-hour charge. Reply Brief, SCE, R-CE-01, 39.

**Evaluation of Positions**

The California parties' recommendations are widely divergent. The CPUC claims that BPA does not incur costs in guaranteeing delivery at any time. Enderby and Mattson, CPUC, E-CP-01, 33. PG&E contends that BPA incurs no costs for guaranteeing delivery during spill conditions. Kemp, PG&E, E-GA-01, 11; E-GA-01S, 2. These positions are disputed by BPA and the Northwest Parties. Griffin, BPA, STR 951; Mizer, NWP, STR 1242-1243. Despite rejecting a cost basis, the CPUC and PG&E recommend, respectively, a "premium" or "small incentive" for guaranteed delivery sales.

LADWP recognizes that BPA does incur costs in guaranteeing delivery, but they object to the level of the guarantee surcharge and argue that it is not adequately quantified.  SCE recognizes that there are risks (and associated costs) in guaranteed delivery (a position supported by BPA).  Griffin, BPA, STR 950-951.  And PG&E states that during nonspill conditions the cost of guaranteed delivery energy is related to "operative BPA thermal capacity costs."  The latter approach acknowledges costs associated with guaranteed delivery only when thermal resources operate concurrently with deliveries of guaranteed nonfirm energy.  PG&E additionally contends that a 3.4 mills per
[page 320] kilowatt-hour charge will be too high to find many buyers.  Kemp, PG&E, E-GA-01, 11-12.

BPA proposes in rebuttal testimony to remove the cost basis for the guaranteed delivery calculation.  Metcalf, BPA, E-BPA-64R, 30.  This is appropriate for two reasons.  First, It is admittedly difficult to determine the cost of guaranteed delivery under all operating conditions. Griffin, BPA, STR 951.  Second, thermal capacity costs, the previous cost basis, are now included in the target average revenue calculation (as are all other system costs that contribute to the generation of nonfirm energy).  This procedure is consistent with the Northwest Parties' recommendation.  Opatrny and Cook, NWP, E-NF-02, 7.  The proposed charge is increased slightly over the current NF-83 charge.  A charge which appears to have been favorably received by BPA's customers.  Metcalf, BPA, STR 812.  Setting the charge in this method and at this level recognizes (1) the problems of cost quantification, (2) the new target average revenue calculation, and (3) the need for an incentive if BPA's schedulers are to offer guaranteed delivery.  Metcalf, BPA, STR 811.  The NF-85 rate schedule as a whole is cost justified, based on the target average revenue calculation.  It is appropriate that individual components, such as the guaranteed delivery surcharge, be based on marketing considerations and administrative convenience.

**Decision**

*The rate for guaranteed delivery of NF-85 energy is 2.0 mills per kilowatt-hour.  The level of this charge accounts for uncertainty in cost determination and, more importantly, should be attractive to buyers.*

### 6.  Other Nonfirm Energy Issues

**Issue #1**

*Will BPA's nonfirm energy rates promote efficiency?*

**Summary of Positions**

BPA argues that the NF-85 rate schedule is efficient because it promotes displacement of high cost resources.  Metcalf, BPA, E-BPA-37, 3-4.

PG&E argues that the NF-85 rate schedule is not efficient; BPA could lose nonfirm energy market share during onpeak hours due to increased competition from PNW thermal generation.

Kemp, PG&E, E-GA-01, 6-7; E-GA-03SR, 3. During a majority of off-peak and shoulder hours, BPA's proposed Standard rate will not be competitive with alternative incremental resources available to PG&E. Kemp, PG&E, E-GA-03SR, 2. They also do not consider value-based rates capable of achieving efficiency. Kemp, PG&E, E-GA-02R, 4.

The Northwest Parties assert that the High Cost Displacement rate should be eliminated because it will not efficiently displace California resources or
[page 321] California utilities' purchases from Inland Southwest coal plants. Opatrny and Cook, NWP, E-NF-05SR, 7.

CPUC claims that the "most efficient use of resources occurs when prices are based on the sellers' marginal costs." BPA's NF-85 rate schedule is inefficient because efficiency is served only by a share-the-savings structure based on the seller's cost plus a fixed adder. Enderby and Mattson, CPUC, E-CP-02R, 8-9.

LADWP also argues that rates are not efficient unless they are based on marginal costs. Initial Brief, LADWP, B-LA-01, 11. LADWP further argues that NF-85 is in efficient because BPA has neglected to consider the NF-85 rate schedule's effect on efficient consumption. Parmesano and Whitney, LADWP, E-LA-01, 22-23, Exhibit (HP-9); Initial Brief, LADWP, B-LA-01, 12-14.

**Evaluation of Positions**

PG&E argues that the NF-85 rate schedule is in efficient because it encourages other PNW generating utilities to run their thermal resources and market the output to the PSW rather than purchase Standard rate energy and displace their thermal resources. Kemp, PG&E, E-GA-01, 6; E-GA-03R, 3. They claim that the economic incentive is to operate and sell even during spill conditions. *Id*., E-GA-01, 6. They claim that a resource owner will generate and sell if the difference between the incremental cost and the NF-85 Standard rate exceeds the difference between the incremental cost and BPA's displacement rate. They base this decision rule on two assumptions: (1) export sales, whether a PNW utility's or BPA's, will be at the Standard rate or higher; and (2) there is a one-for-one correspondence between generation of nonfirm energy and sales of such energy to the PSW. Neither assumption has any factual basis. First, BPA's nonfirm energy rates are designed to respond to market conditions by selling below the Standard rate if conditions warrant. Second, Intertie allocation and scheduling does not assure that any utility (or BPA, for that matter) receives Intertie access in one-for-one correspondence to secondary energy availability. Thus, any PNW generating utility weighing the choices of (1) generate and sell, or (2) purchase and displace must consider at least two factors that PG&E's analysis ignores: the generating utility may have to offer energy at a rate below the NF-85 Standard rate; and only a portion of their output will likely have Intertie access. Finally, PG&E simply miscounts the amount of power the thermal plant owner would have in the two cases. If the plant owner purchases energy at BPA's High or Low Cost Displacement rates and shuts the plant down as required, the owner has exactly the same amount of surplus power to market as if no displacement purchases had been made. Thus, there is no incentive to run the plant during spill conditions. PG&E's analysis is completely erroneous.

PG&E also contends that "[v]alue-based rates can be efficient only within a competitive market structure" and, in such a situation, value-based rates would arrive at the same price as would cost-based rates. Kemp, PG&E, E-GA-02R, 4. This argument is also made by CPUC. Enderby and Mattson, CPUC, E-CP-02R, 8. PG&E's and CPUC's arguments ignore the ability of regulated
[page 322] prices to approximate the competitive market result. They also ignore the wide divergence between BPA's costs and PSW costs, and the bottleneck created by the PSW Intertie. Finally, value-based rates can approximate the allocative efficiency results of a competitive market. Hull, SCE, E-CE-03RA, F-38-39.

The CPUC claims that share-the-savings rates based on the seller's cost plus a fixed adder are flexible, equitable, efficient, and yield low rates. This form, the CPUC claims, is more effective than either a rate based on one-half the sum of seller and buyer incremental and decremental costs, or a rate based on a percentage of the buyer's decremental cost. Enderby and Mattson, CPUC, E-CP-02R, 9. BPA proposes that the Share-the-Savings rate be calculated as a percentage of the buyer's decremental cost. BPA proposes this formula rather than other alternatives because (1) it is difficult to identify BPA's nonfirm energy costs during certain periods, and (2) basing the rate on decremental cost is easier to administer. Metcalf, BPA, E-BPA-37, 12. No persuasive evidence was introduced that overcomes BPA's concerns regarding cost measurement and administrative problems with alternative methods. No evidence was presented supporting the alleged greater "effectiveness." BPA's proposed formula is not uncommon; share-the-savings transactions based on decremental cost frequently are based on 85 percent of buyer's decremental cost, which is 10 percent higher than BPA's proposal. Opatrny and Cook, NWP, E-NF-04R, 8.

LADWP calculates a net efficiency loss that results from "charging nonfirm rates above costs and using the excess revenues to reduce firm rates in the PNW." Parmesano and Whitney, LADWP, E-LA-01, 22-23, Exhibit (HP-9). The Northwest Parties note that "using excess revenues from nonfirm or economy energy sales to reduce firm rates is the industry norm for both wholesale and retail ratemaking." Opatrny and Cook, NWP, E-NF-04R, 28. The Northwest Parties argue that LADWP's calculation of consumption efficiency "improperly comingles firm and nonfirm revenues," and that "the most efficient method for pricing economy energy is share-the-savings." *Id*. 29.

The Northwest Parties argue that the High Cost Displacement rate may not be competitive in the California market with inland Southwest economy energy rates. Opatrny and Cook, NWP, E-NF-05SR, 7. They assert that few resources in California can be displaced at 14 mills per kilowatt-hour that cannot also be displaced at BPA's Standard rate. Additionally, they contend that BPA's Southwest utility competitors will lower their prices below BPA's price during light load hours. Opatrny and Cook, Northwest Parties, E-NF-05SR, 7. They claim that the rate "may become the functional equivalent of the spill rate" because California utilities will adjust operationally to shift their energy needs from on-peak to off-peak periods, resulting in lower nonfirm energy revenues. *Id*., 8.

The record is not persuasive that the inland Southwest will measurably undercut BPA's High Cost Displacement rate. The 14.0 mills per kilowatt-hour (to the PSW) High Cost Displacement rate is lower than inland Southwest variable production costs. Metcalf, BPA, E-BPA-64R, A14. Further, the record [page 323] is not clear that PSW utilities are able to shift significantly their on-peak energy needs to off-peak periods. However, if experience indicates that California utilities are playing the "waiting game," which NWP claims would likely occur, it is reasonable to assume that BPA's revenue analyses will identify this trend and BPA may then elect not to offer this rate. Griffin, BPA, STR 960-967. Finally, the High Cost Displacement rate is fundamentally different from the spill rates of previous nonfirm energy rate schedules. It is unlikely that the High Cost Displacement rate will become functionally equivalent to a spill rate because (1) it will be implemented based on market, not operational, considerations, and (2) a purchaser may be required to displace a resource, purchase, or alternate fuel source.

**Decision**

*BPA's NF-85 rate promotes efficiency. It is flexible, allowing for displacement first of high cost resources and then, if enough supply exists, lower cost resources. The Share-the-Savings rate avoids administrative problems that other share-the-savings rates incur.*

**Issue #2**

*Will BPA's nonfirm energy rates promote equity?*

**Summary of Positions**

The NF-85 rate schedule is equitable for two reasons. First, BPA's forecasted NF-85 revenues will be closer to the benefits that California utilities receive from NF-85 purchases. Second, the average NF-85 rate will be lower than BPA's rates for firm power. Metcalf, BPA, E-BPA-37, 16.

PG&E contends that a rate based on 75 percent of the purchaser's decremental cost results in benefits "heavily weighted toward BPA." Kemp, PG&E, E-GA-02R, 2. They contend that the Share-the-Savings rate will create a cross-subsidy both within the nonfirm energy class and between nonfirm energy customers and firm power customers. *Id*. 1-2; E-GA-03SR, 3.

CPUC claims that equity is only served by a Share-the-Savings rate structure when such a structure is based on the seller’s cost plus a fixed adder. Enderby and Mattson, CPUC, E-CP-02R, 8-9.

SCE argues that BPA's proposed nonfirm energy rates are in equitable because (1) they exceed BPA's costs, (2) the average nonfirm energy rate exceeds the average Priority Firm rate, and (3) PSW utilities will pay higher rates than PNW utilities yet receive a "similar quality of service." Initial Brief, SCE, B-CE-01, 22.

**Evaluation of Positions**

The California parties' arguments generally address four points. They argue that BPA's Nonfirm Energy rates are in equitable because: (1) they
[page 324] exceed cost; (2) the average Nonfirm Energy rate to California exceeds the average Priority Firm Power rate; (3) PSW utilities will pay a much higher rate than PNW utilities for similar service, and revenues from PSW customers will subsidize firm power customers; and (4) BPA's Share-the-Savings rate will result in a majority of the transaction benefits going to BPA. The last point is in Issue #3 of this section, below.

The California parties are incorrect in stating that BPA's Nonfirm Energy rates exceed cost. The NF-85 Contract rate, which is based on the average rate of all forecasted nonfirm energy sales, is 18.1 mills per kilowatt-hour. This is less than the NF-85 target average revenue of 21.7 mills per kilowatt-hour, which represents BPA's fully distributed cost of providing nonfirm energy.

The California parties are correct in noting that PSW purchasers of nonfirm energy will pay a higher average rate than PNW purchasers. This is not in equitable, and actually means that BPA's revenues from PSW sales will be more in line with the benefits that PSW utilities will receive from nonfirm energy purchases. With respect to individual sales, some sales to California utilities are forecast at the High Cost Displacement rate and are thus below cost.

PG&E also contends that "[e]quitable ratemaking would require a consistent positive relationship between BPA's costs and rates" and BPA's rates based on Share-the-Savings principles are inequitable because they are based on the buyer's cost and not on BPA's costs. Kemp, PG&E, E-GA-02R, 2. This position was directed at the NF-85 Variable Displacement rate, which is now eliminated from the NF-85 schedule. PG&E’s position was incorrect because any such sales would have been below BPA's cost. PG&E’s contention that share-the-savings rates are in equitable if they are based only on the buyer’s cost is unsupported by the record and is inconsistent with Judge Miller’s Initial Decision.

**Decision**

*Nonfirm energy customers in the PSW do not subsidize those in the PNW, nor does this rate reflect an inequitable allocation of costs between nonfirm energy and firm power customers. Many sales to the PSW will actually be below BPA's cost of providing nonfirm energy. The NF-85 rate schedule is equitable; the average NF-85 rate is lower than BPA's firm power rates.*

**Issue #3**

*What is the measure of benefits that California utilities derive from purchasing nonfirm energy from BPA?*

**Summary of Positions**

BPA asserts that the benefits to purchasers of nonfirm energy have, in recent years, been far greater than the revenues received by BPA from such [page 325] sales. Metcalf, BPA, E-BPA-37, 3. The fuel cost benefits of NF-83 purchases by four large California utilities are more than four times the revenues BPA has received. *Id.*, Attachment 4; E-BPA-64R, Attachment A5. The Standard rate, the highest of the NF-85 rate components, is set at a level far below the decremental cost of many California resources. Metcalf, BPA, E-BPA-37, 16.

The CEC argues that BPA overestimates the value of its nonfirm energy to California utilities. Marcus, CEC, E-CC-01, 11. The CEC argues that in calculating benefits BPA should use the avoidable costs of gas to the gas company rather than the costs quoted to the electric utility of a combined gas and electric company. Marcus, CEC, E-CC-01, 13. The benefit to combined ratepayers of electric utilities and gas utilities is the incremental cost of gas. Marcus, CEC, E-CC-01, 14; E-CC-02R, 3; E-CC-03SR, 3; Initial Brief, CEC, B-CC-01, 9-12; Reply Brief, CEC, B-CC-02, 3-4.

The CEC also argues that BPA overestimates benefits by using average heat rates of oil and gas plants, which generally exceed the instantaneous avoidable incremental cost. Marcus, CEC, E-CC-01, 16; E-CC-03SR, 3; Initial Brief, CEC, B-CC-01, 12-13.

The CEC asserts that it is incorrect for BPA to assume that all energy sold to California displaces oil and gas generation. BPA's energy actually competes during off-peak hours with economy energy from other sources. Marcus, CEC, E-CC-01, 18; E-CC-03SR, 4; Initial Brief, CEC, B-CC-01, 14.

The CEC asserts that municipal utilities, who will benefit the most from intertie expansion, have rate structures based on embedded costs, and therefore will benefit to a lesser extent than the cost of incremental alternate fuel. Marcus, CEC, E-CC-01, 20-22; B-CC-01, 15-16.

The CEC asserts that during minimum load periods the measure of benefits received is determined by the price of economy energy at that time, not the average price of economy energy during all hours. Marcus, CEC, E-CC-03SR, 5.

LADWP asserts that BPA's analyses of benefits should be based on the difference between what is paid for BPA's energy and the price California utilities would pay for equivalent energy from other sources. Therefore, BPA has distorted the value to California of nonfirm energy. Initial Brief, LADWP, B-LA-01, 6.

**Evaluation of Positions**

The CEC's argument that the cost of gas to a combined gas and electric utility should be used to estimate the value of BPA's nonfirm energy has merit if the combined operations are considered to be one utility.

The CEC's argument that average heat rates are inappropriate appears reasonable. However, this argument is undocumented and unverified, so no adjustment is possible. BPA must rely on the best evidence available, and CEC has not presented evidence sufficient to examine this issue in more detail.
[page 326]

The CEC correctly argues that BPA assumes that all energy sold to California displaces oil and gas. It is reasonable to assume that BPA's energy competes during some offpeak hours with economy energy from other sources. Again, however, CEC has not presented evidence sufficient to examine this issue in more detail. Further, the fact that at least some purchases are at share-the-savings rates means that the avoidable cost of a purchase is also tied to system decremental fuel cost.

The CEC's comments regarding benefits to municipal utilities may have merit. However, such comments are not relevant to BPA's calculations of historical benefits in the 1985 rate case because BPA's analyses of benefits in Exhibits E-BPA-37 and E-BPA-64R do not consider municipal utilities.

Similarly, the CEC correctly asserts that the measure of benefits during minimum load hours should be based on economy energy prices during those hours, but this observation alone does not assist are calculation of benefits, absent further documentation.

LADWP's suggestion that benefits can be measured in terms of alternative purchases appears to have merit. On the other hand, when the alternative purchase is not made, its availability is somewhat speculative. More than one purchaser of BPA nonfirm energy may be counting the same alternative. In this situation, total benefits to California could be seriously understated by using alternative purchase calculations. Further, when alternative purchases are priced by decremental cost formulae, fuel prices remain relevant.

**Decision**

*BPA estimates of benefits received by California from nonfirm energy purchases may be overstated. However, corrections or adjustments are not possible absent better documentation from PSW utilities or regulatory bodies. It is evident that benefits received by California utilities still exceed those received by BPA. BPA's SS-85 rate schedule is designed to ensure that benefits will be equitably shared even if California decremental costs decline significantly, as argued by the CEC.*

**Issue #4**

*Should BPA establish a long term rate cap or formula for its nonfirm energy rate?*

**Summary of Positions**

BPA is willing to look into ways of fixing the Standard rate mechanism for a longer term. Metcalf, BPA, E-BPA-37, 17.

The CEC recommends that BPA adopt a long term rate formula or rate cap for the nonfirm energy rate schedule. Marcus, CEC, E-CC-01, 5; Initial Brief, CEC, B-CC-01, 30-33. The CEC proposes a rate cap on the nonfirm energy
[page 327] Standard rate for 20 years. This rate cap for nonguaranteed sales would be 80 percent of the priority firm rate less the cost of "transmission facilities clearly not used to transmit

nonfirm energy." Marcus, CEC, E-CC-01, 27. For guaranteed delivery, the rate cap would be 90 percent. *Id*. The rate cap would be "fully revocable in the next rate proceeding unless BPA executes agreements with California parties" during the rate period. *Id*., 29.

The Northwest Parties object to a rate cap as suggested by CEC because it would price nonfirm energy below cost. Opatrny and Cook, NWP, E-NF-04R, 18. They claim that the objective of rate stability which a rate cap seeks to achieve can be achieved by a Share-the-Savings rate form. *Id*., 19.

**Evaluation of Positions**

The CEC bases its recommendation for a rate formula or cap on the need for nonfirm energy rate certainty over a number of years so that California utilities can determine the potential benefits of future investment in the Pacific Southwest Intertie. The CEC states that California utilities need the ability "to accurately forecast the benefits available to them from increased intertie capacity." Marcus, CEC, E-CC-01, 4-5; Initial Brief, CEC, B-CC-01, 30. Without the assurance of a rate cap or rate formula, "California utilities' investments in new transmission may not be safe." Marcus, CEC, E-CC-01, 25. The CEC notes conditions that currently prevent California utilities from forecasting BPA's nonfirm energy rates. These conditions include (1) no cost-of-service basis for nonfirm energy rates, (2) nonfirm energy rate calculations and rate structures that have differed each year since 1979, and (3) encouragement by Northwest parties to raise the NF-85 rate even higher than BPA's proposal. *Id*., 5-7. The CEC states that "[u]nder the currently proposed Bonneville rate schedule, with the level up as high as 23 mills, I think [California utilities' investment in new intertie lines]would be close to the edge [as a marginal investment]." Marcus, CEC, STR 1090-1091. PG&E argues that the proposed NF-85 rates erode the cost-effectiveness of California utility investment in additional Intertie capacity. Kemp, PG&E, E-GA-03SR, 3.

The premise of CEC's proposed rate cap is that California utilities ' Southwest Intertie investment decisions are made highly uncertain by BPA's proposed NF-85 rate schedule. However, evidence suggests that, despite any nonfirm energy rate uncertainty that may exist, California utility interest in Southwest Intertie projects is high. In response to a FEDERAL REGISTER notice calling for statements of interest in expansion of the Intertie, interest in the projected additional Intertie capacity exceeded such additional capacity by possibly as much as a factor of three. Marcus, CEC, STR 1093.

Because the cost of producing nonfirm energy is close to BPA's total system cost, the Northwest Parties are correct in noting that a rate cap based on either 80 or 90 percent of the Priority Firm Power rate would fail to recover the costs of production.

The CEC proposal for a rate cap is one-sided. They propose that BPA unilaterally adopt a rate cap while the California parties retain the ability
[page 328] to argue for rates far below the rate cap and BPA's cost of service. A properly designed long term formula may need to be included in contracts as well as subjected to a 7(i) process to ensure that all parties will abide by it.

**Decision**

*It is now a good time to explore the possibility of establishing a long term nonfirm energy rate methodology for sales to California. The proper process for developing and establishing such a methodology is not clear.*

*The long term methodology could take one of two forms. It could be a cost-based rate similar to BPA's proposed implementation of the Miller decision, or it could be a Share-the-Savings rate like the optional SS-85 rate BPA is proposing on an experimental basis. It may be that such a rate structure would provide a greater long term assurance of benefits to California utilities, given the uncertain nature of their alternative costs.*

### 7. Nonfirm Revenue Analysis Program

### Introduction

The Nonfirm Revenue Analysis Program (NFRAP) is a computerized model that estimates sales and revenues for categories whose sales vary depending on streamflow conditions. The NFRAP uses information about historical water conditions to develop its estimates. This information is derived from the regional hydroregulation study and the Federal Secondary Energy Analysis. The outputs of the NFRAP include: Pacific Northwest and Pacific Southwest nonfirm energy sales and revenues, total service to interruptible loads of the direct service industries, Coordination Agreement Interchange sales and revenues, Capacity/Energy Exchange obligation energy sales and revenues, displacement of firm purchases from BPA by computed requirements customers, and estimated non-Federal use of the Pacific Intertie (for wheeling rate development).

The NFRAP includes a market for firm and nonfirm energy sales to California based on the transmission capability of the Pacific Intertie. The NFRAP reduces intertie capability based on the assumption that "minimum generation" limitations (which may be caused by numerous factors) prevent the Intertie from being fully loaded during certain times of the day or year. BPA and various parties disagree on the extent of the "minimum generation" limitation, and on how the limitation should be modeled.

**Issue #1**

*How should the market limitation for nonfirm energy sales to California from the PNW be modeled in the NFRAP?*

[page 329]

**Summary of Positions**

In BPA's initial proposal and supplemental testimony the NFRAP limited the PSW market for all firm and nonfirm energy sales to 1,000 megawatts for 6 hours of every day (one-fourth of all hours). BPA, E-BPA-05A, 246; Roghair, BPA, E-BPA-16S, 5. This was to account for what BPA characterized as "minimum generation" limitations to purchases by California utilities. In BPA's rebuttal testimony the NFRAP was revised to model the revised nonfirm energy rate schedule. Roghair, BPA, E-BPA-66R. The revised NFRAP divided the California market into heavy load hours and light load hours. In general terms, heavy load hours are daytime hours during which utilities experience no minimum generation limitations. Light load hours are the remaining nighttime and weekend hours during which utilities may experience minimum generation limitations. The revised NFRAP modeled no minimum generation limitation on the heavy load hour market for nonfirm energy. Roghair, BPA, E-BPA-66R, 4-5. The light load hour California market was limited to a maximum of 3,000 megawatts for minimum generation constraints. The decreased limitation (from a 1,000 megawatt market to a 3,000 megawatt market) recognized that the High Cost Displacement rate will allow California utilities economically to purchase BPA nonfirm energy rather than energy from other sources. Roghair, BPA, E-BPA-66R, 5, 8-9. In rebuttal testimony the NFRAP modeled the light load hours, and thus High Cost Displacement rate sales, to occur 31 percent of the time, relying on CEC observations of historical operations and on expected nuclear project additions to serve California utilities. Roghair, BPA, E-BPA-66R, 2, 5-6.

The PGP argues that the NFRAP incorrectly restricts the California market for nonfirm energy, and that there should not be an Intertie market limitation. Opatrny/Spettel, PGP, E-PG-07, 3; Spettel, PGP, E-PG-07S, 5.

The CEC suggests that minimum generation hours in the PSW can be significant, were 52 hours per week during winter in 1983, and are likely to increase in the future. Marcus, CEC, E-CC-02R, 7-8. Elsewhere, the CEC argues that the light load hours used in BPA's rebuttal testimony are overestimated when compared with historical data from Southern California Edison, and should be reduced to 35 hours per week (about 21 percent of all hours). This reduction in light load hours modeled in the NFRAP would decrease High Cost Displacement rate sales and thus lower the NF-85 Standard rate. Marcus, CEC, E-CC-03SR, 6-7.

**Evaluation of Positions**

BPA's limitation of the market for sales of energy to California utilities as presented in the initial proposal and supplemental testimony was a reasonable means of accounting for California utilities ' inability to purchase unlimited amounts of PNW energy at BPA’s Standard nonfirm energy rate. The limitation was based on observations of actual energy sales and professional judgment. However, by limiting both firm and nonfirm energy sales to 1,000 megawatts for one-fourth of all hours, the market was constricted excessively.



The NFRAP presented in BPA's rebuttal testimony correctly included no minimum generation limitations on heavy load hour markets. It also eased the light load hour limitation by enlarging the California light load hour market from 1,000 to 3,000 MW. The less restrictive limitation on light load hour markets is more reasonable, particularly considering that the nonfirm energy rate modeled for most sales to that market is reduced well below the Standard nonfirm energy rate. The percentage of light load hours modeled in the NFRAP (31 percent) for FY 1987 is not unreasonable in light of the CEC’s observations of historical minimum generation hours and expected California utility nuclear project additions.

The PGP argument that BPA has incorrectly restricted the California market size for nonfirm energy is not reasonable and was rebutted by BPA. Roghair, BPA, E-BPA-60R, 4-6. There are foreseeable limitations on the amount of nonfirm energy that the PNW will be able to sell to California utilities, at any given price.

The CEC argument that minimum load hours in the PSW can be significant and that they are likely to Increase in the future is reasonable. The argument that BPA overestimated the minimum load hours in rebuttal testimony is not correct. It is correct that the historical number of minimum generation hours normally has been less than the approximate 52 hours per week used in the NFRAP. Historical levels are not directly applicable to the 1987 test year, when the California resource situation may be significantly different from the historical situation. However, it may not be prudent for the NFRAP to model only High Cost Displacement rate sales during a number of hours that deviates greatly from historical minimum generation hours. This is particularly true if the assumed sales cause the NF-85 Standard rate to increase.

In rebuttal testimony, BPA modeled the light load hour market to be served at the High Cost Displacement rate. Roghair, BPA, E-BPA-66R, 2. It is not unreasonable to assume that minimum generation will occur for 31 percent of all hours, yet modeling High Cost Displacement rate sales for that portion of the time may not be prudent since it increases the NF-85 Standard rate.

BPA noted that in actual practice, sales at the various NF-85 rates may occur on any hour of the day. Griffin, BPA, STR 972. By assuming that some Standard rate sales may occur during hours of minimum generation, the increase in the Standard rate can be eliminated. This can be accomplished by the reduction in High Cost Displacement rate sales urged by the CEC. By assuming minimum generation hours to occur 31 percent of all hours, and assuming High Cost Displacement rate sales to occur during 70 percent of minimum generation hours, the CEC's recommendation to restrict High Cost Displacement rate sales to 21 percent of all hours can substantially be accomplished. The CEC's recommendation to limit High Cost Displacement rate sales to approximately 21 percent of all hours is reasonable.

**<u>Decision</u>**

*It is appropriate for the NFRAP to mode a market limitation for nonfirm energy sales to California, and BPA will continue to do so. The market*
[page 331] *limitation is based on historical data. It is modeled to occur during 31 percent of all hours, and High Cost Displacement rate sales are modeled to occur during 21.7 percent of all hours.*

**<u>Issue #2</u>**

*How should the NFRAP model the use of non-Federal nonfirm energy?*

**<u>Summary of Positions</u>**

The NFRAP in BPA's supplemental testimony, E-BPA-16S, modeled PNW non-Federal nonfirm energy to displace PNW thermal resources before being offered to the PSW over the Intertie. Roghair, BPA, STR 320-321.

The ICP argues that the NFRAP incorrectly models actual operations. The ICP asserts that non-Federal nonfirm energy will be offered for sale to California utilities before displacing PNW thermal, so long as the nonfirm energy can be sold to the Intertie market at a rate higher than the costs of running the PNW thermal and so long as the Intertie is not filled. Wilson, ICP, E-IC-09S, 7.

**Evaluation of Positions**

BPA's modeling of non-Federal nonfirm energy sales in the NFRAP was inappropriate. So long as the Intertie market remains unfilled and nonfirm energy can be sold to the Intertie market for more than the variable costs of thermal resources, it is prudent to assume that those resources will continue to operate and nonfirm energy will be sold over the Intertie.

The ICP assertion that non-Federal nonfirm energy would be offered to California utilities at BPA's Standard nonfirm energy rate rather than being used to displace PNW baseload thermal resources is reasonable under circumstances where the costs of operating the thermal resources are lower than the BPA Standard nonfirm energy rate. By this procedure, non-Federal entitles can cover the operating costs of thermal resources while obtaining a profit from sales of nonfirm energy to the PSW. This profit would be foregone if the thermal resources were displaced. It is appropriate for the NFRAP to model non-Federal nonfirm energy sales first to serve Intertie markets until they are filled, and second to displace PNW baseload thermal resources.

**Decision**

*In water conditions when there is unused Intertie capability and the nonfirm energy rate exceeds operating costs of thermal resources, the NFRAP will model non-Federal nonfirm energy to be used in the manner recommended by the ICP. The NFRAP will model the sale of non-Federal nonfirm energy to California purchasers at BPA's Standard nonfirm energy rate, and then to displace PNW baseload thermal resources.*

[page 332]

## J. Irrigation Discount

Prior to 1974, BPA included a special irrigation discount in its preference rate for irrigation loads. This discount was phased out between 1974 and 1979. In response to the current economic condition in Northwest agriculture and in response to testimony filed in the recent rate proceeding, an irrigation discount is included in the proposed PF-85 and NR-85 rate schedules.

**Issue #1**

*Should there be an irrigation discount in the PF and NR rate schedules?*

**Summary of Positions**

In the initial proposal BPA did not include an irrigation discount. Many of the characteristics of BPA's firm power rates already operate to reduce costs to BPA's irrigation utility customers. First, BPA seasonally differentiates its firm power rates. The Priority Firm capacity and energy rates are lower during the summer when irrigation loads mainly occur. This differential between summer and winter rates has placed a heavier burden on winter customers, particularly on winter capacity customers. Second, the Low Density Discount applies to most of BPA's customers who have irrigation loads. The Low Density Discount lowers retail rates of utilities with major irrigation loads by an average of 3.5 percent. Peters, BPA, E-BPA-41, 2. Third, BPA's Priority Firm demand charge is diurnally differentiated. A study prepared for BPA showed that only a few utilities pass through the diurnally-differentiated wholesale rate design feature to their irrigating consumers. McKusick, BPA, E-BPA-44A2, 28. In addition to these rate design features, BPA also instituted a series of programs whereby metered requirements customers could purchase nonfirm energy to serve their irrigation loads in the spring. Peters, BPA, E-BPA-41, 1-2. BPA's analysis shows that irrigation demand for electricity is mostly inelastic with respect to wholesale electricity prices, so higher BPA revenues from a discount are unlikely. McKusick, BPA, E-BPA-44A, 2.

NIU proposes a "summer seasonal load provision" for the Priority Firm Power rate schedule. NIU asserts that various cost and revenue credit adjustments that would reduce the PF summer rate are justified by the nature of the irrigation load. Dawsey, NIU, E-NI-01, 8-11; Hittle, NIU, E-NI-02, 12; Gates, NIU, E-NI-03, 8-13. This concept is endorsed by the Washington State Farm Bureau (WSFB). Beightol, WSFB, E-WS-01, 1-6.

NIU and the Idaho Cooperative Utilities Association (ICUA) disagree with BPA's conclusion that irrigation loads are inelastic. They allege that BPA's analysis understates the ability of irrigators to respond to price; a discount might actually increase revenues to BPA. Jones, NIU, E-NI-04, 5-6; Whitelaw, ICUA, E-IU-02R, 10. ICUA states that any rate relief for irrigation
[page 333] loads must not exacerbate the existing differential between winter and summer capacity charges and, if possible, should reduce the differential. Initial Brief, ICUA, B-IU-01, 12.

NIU identified, as an alternative to a summer seasonal load provision, an irrigation discount similar to the one included in the pre-1974 Wholesale Power Rate schedules. While the reasons for the pre-1974 irrigation discount differ from the reasons for a summer seasonal load provision in the 1985 PF rate, both methods would result in an energy discount for irrigation loads. Dawsey, NIU, E-NI-01, 12.

The Northwest States Irrigation Executive Committee takes the position that BPA should return to the irrigation discount because farmers invested millions of dollars in irrigation equipment with the understanding that they would receive low rates from BPA into the future. Jones, NIU, E-NI-04, 18.

WPAG opposes a special discount for any subset of BPA's customers unless a compensating benefit is provided to the customers who are paying for the rate concession. They allege that there is no persuasive evidence that the economic situation of irrigated agriculture is measurably worse than that faced by other regional industries, such as timber products, mining, and manufacturing. Furthermore, they state that granting concessionary rates causes BPA to choose which consumer groups should be protected from the impact of market forces beyond BPA's control and which customers will be required to provide that protection. If rate concessions are required by irrigation loads, they should be established at the retail level by the utilities that serve this load. Finally, such rates may encourage farmers to make inefficient capital investments based upon faulty price signals. Hutchison, et al., WPAG, E-WA-02R, 13-16.

**Evaluation of Positions**

A number of parties agree that agriculture is an important economic sector in the Pacific Northwest. For every kilowatt-hour used for irrigation on the farm in 1980, another 1.7 kilowatt-hours were used by other economic sectors related to irrigated agriculture. These economic sectors include food processing, commercial/industrial, and residential (jobs and households dependent on irrigated agriculture). McKusick, BPA, E-BPA-44A3, vi; Jones, NIU, E-NI-04, 2; Ashcom, Oregon Farm Bureau Federation (OFBF), E-OF-01, 3.

NIU describes the negative stress agriculture lenders are beginning to experience as their borrowers have difficulty with loan repayments. Jones, NIU, E-NI-04, 6-8. WSFB states that a record number of farms are either going out of business or experiencing economic hardships. Beightol, WSFB, E-WS-01, 4. Northwest States Irrigation Executive Committee describes falling land values, with irrigated land that readily sold for $2,000 an acre 3 years ago unable to be sold for $1,600 today. Akins, NSIEC, E-NE-01, 2.

While there is no disagreement over the financial condition of farmers. opinions diverge over the role of electricity prices in the economic health of
[page 334] irrigated agriculture. Irrigation loads have declined in the past few years. It is difficult to conclude that this change in loads is due to electricity price alone, because it is necessary to separate price impacts from weather, conservation, new irrigation technology, changing cropping patterns, and low commodity prices. Furthermore, electricity accounts for only a small part of total production costs for most farmers. Peters, BPA, E-BPA-41, 2.

In order to assess the impacts of wholesale electricity rate level and design on irrigated agriculture, BPA contracted with Northwest Economic Associates (NEA). NEA developed a model, consulting with NIU, utilities, and the Departments of Agriculture in Idaho, Oregon, and Washington. One conclusion of the NEA study was that, for the period analyzed, demand for electricity by irrigated agriculture in the PNW is not sensitive to relatively small changes in wholesale power rates (10 to 20 percent). The price elasticity of electricity demand is less (in absolute value) than -.l for such changes. For larger wholesale electricity price changes, demand for electricity by irrigated agriculture is more sensitive, but still inelastic. One reason for this general unresponsiveness to electricity price is the fact that electricity generally accounts for only a small percentage of total production cost. Larger electricity price increases, however, would be expected to induce water and energy conservation. McKusick, BPA, E-BPA-44A2, 2.

The NEA study also identified about 10 to 15 percent of the irrigated acreage as rate sensitive, defined in terms of low crop prices combined with electricity costs that are at least 15 percent of total production costs. This more sensitive acreage accounts for 20 to 30 percent of BPA's total irrigation load. These rate sensitive areas are characterized by high or long lifts, sandy soils, and limited cropping opportunities (cropping dominated by hays and grains). McKusick, BPA, E-BPA-44, and 44A2, 65-71.

NIU disagrees with the NEA study on two points. First, NIU argues that the share of electricity in total production costs for irrigated wheat and alfalfa hay varies from 10 to 35 percent, with most irrigators reporting electricity costs in the 15 to 25 percent range. Furthermore, hay and grain production induces the largest total energy use in the commercial/industrial sector. Jones, NIU, E-NI-04, 2-4. WSFB, on the other hand, reports power costs at Mercer Ranch, Inc., a high lift farm, as 5 percent for potatoes and 16 percent for wheat in 1983. Beightol, WSFB, E-WS-01, 2. These cost percentages are consistent with the NEA study. Second, NIU disputes NEA's claim that irrigation demand for electricity is mostly inelastic. NIU states that WEA's analysis did not take into account key factors in determining the price elasticity of irrigated agriculture; for example, farm equity, financial reserves, debt/asset ratios, and the cumulative effect of a series of "small" electricity price increases. Jones, NIU, E-NI-04, 6. However, NEA's model of farm budgets and farm profits did take into account the specific items mentioned by NIU as they affect the profitability of farms. McKusick, BPA, TR 3565.

ICUA supports NIU's challenge to NEA's elasticity results. ICUA cites a study that estimated short- and long-run elasticities for the Northwest Region [page 335] at -1.191 and -1.286. Whitelaw, ICUA, E-IU-02R, 10. Such elasticities imply that as the price of electricity goes up, total utility revenues would go down. However, ICUA could cite no studies or experience of utilities in the Northwest that showed an actual decrease in revenues with a rate increase. Whitelaw, ICUA, TR 4273-4274. Furthermore, BPA cited three other studies that reported elasticities for the irrigation demand for electricity in the range of NEA's estimate. McKusick, BPA, TR 3564. ICUA further pointed out that NEA's elasticity estimate was only a short-run estimate. Over time, as farmers replace their equipment and alter their farming practices to give greater weight to expectations about rising electricity costs, the long-run elasticity will exceed the short-run estimate. BPA agrees that the long-run elasticity will probably exceed the short-run estimate. However, there is a high probability that in the long-run, irrigation demand for electricity would still be in elastic. McKusick, BPA, TR 3570.

NIU charges that the use of aggregate data by NEA masks the impact of rate increases. They claim that an accurate picture of the impact of price on irrigation cannot be obtained without considering impacts on a utility on a crop specific basis. Initial Brief, NIU, 8-NI-WS-NE-01, 18. NEA’s analysis is based on 11 production areas in the region, the data from which are then aggregated to a regional basis. However, BPA designs rates to apply region-wide. BPA's own testimony recognizes that areas will experience different rate impacts. McKusick, BPA, E-BPA-44A2, 2; Peters, BPA, E-BPA-41, 3. For areas with extraordinary impacts, rate concessions at the retail level are more appropriate than at a regional wholesale power level. BPA has additional research underway in the areas that NEA has identified as rate-sensitive. McKusick, BPA, E-BPA-44A2, 7.

Only a few of the utilities pass through to their consumers BPA's diurnally-differentiated demand charge, thus denying irrigators access to the potential savings at night and on Sunday resulting from BPA’s zero offpeak capacity charge. Considering the research conducted for BPA by NEA, given the proper price signal irrigators should have some flexibility to shift to off-peak. The greatest flexibility to shift occurs in March-May and September-October when the majority of irrigation could take place in offpeak hours (load factors range between 0.3 and 0.6). The least amount of flexibility occurs in the summer months (load factors range between 0.7 and 0.8). Peters, BPA, E-BPA-41, 3-5; McKusick, BPA, E-BPA-44A2, 3. NIU charges that BPA overstates the value of diurnal rate structures for the majority of irrigators, and that BPA underestimates the practical impediments to the widespread use of this rate form by irrigators. To support this charge, NIU essentially repeats BPA's own testimony to the effect that the value of diurnally-differentiated demand charges is principally limited to the spring and fall months. Initial Brief, NIU, 8-NI-WS-NE-01, 22. However, the NEA load factor analysis implies that, given the proper retail pricing signal, the irrigators could reduce their costs by shifting a portion of their consumption offpeak in all months, although greater shifting would be likely in the spring and fall.

NIU further charges that uncertainty regarding the stability and longevity of the diurnally-differentiation of the demand charge also limits the
[page 336] irrigation user’s ability to plan for and benefit from the use of the rate. Dawsey, NIU, E-NI-01, 6; Initial Brief, NIU, B-NI-WS-NE-01, 2 5. BPA has had diurnally differentiated demand charges since 1979. As NIU points out, these "diurnal rates are based on sound cost-of-service principles." Initial Brief, NIU, B-NI-WS-NE-01, 21-22. Given these cost-of-service principles. BPA cannot guarantee that a specific diurnally-differentiated rate design would be appropriate over time. While recognizing that this may make consumer investment decisions difficult, many other instances of imperfect knowledge exist in the marketplace.

While BPA recognizes the potential benefits of diurnally-differentiated demand charges, the NEA research found that many utilities have little or no experience in offering rates with time-differentiated charges. The utilities express concern about the financial risk of adopting such designs because they do not know how irrigation electricity use might change as a result. McKusick, BPA, E-BPA-44A, 50. BPA plans to work with irrigation utilities to analyze the impact of alternative rate designs. The next phase of the NEA analysis, currently underway, will include the development of a model to analyze the impacts of wholesale rate designs on retail rates, load factors, and utility revenues. The completed model will be available for use by the utilities. Peters, BPA, E-BPA-41, 7. In addition, NEA will be working with the irrigators to identify any technical impediments to switching a portion of their consumption to offpeak periods. McKusisk [sic], BPA, E-BPA-44A2, 7.

The current winter capacity rate has made load management devices and substitution of natural gas and wood for electric space heating economically more attractive. Thus BPA faces the possibility of decreases in revenue from winter sales because of the relatively high winter capacity rates. Initial Brief, WPAG, B-WA-01, 26-27. An irrigation discount combined with less seasonal differentiation of the capacity rate appears a possible solution for the conflicting demands of the summer and winter customers. NIU supports this solution. Hittle, NIU, E-NI-02S, 7.

PNGC supports the establishment of an irrigation discount as proposed by BPA in the Evaluation of the Record. Reply Brief, PNGC, R-PN-01, 1. NIU supports BPA’s proposal of an irrigation discount but believes that the record still amply demonstrates that a summer rate reduction based on the cost of service is justified. Reply Brief, NIU, R-NI-WS-NE-01, 2.

## Decision

*Based on the uncertain long run economic health of irrigated agriculture. the unrefuted testimony presented on the financial hardship of Pacific Northwest irrigated agriculture and on the importance of irrigated agriculture to the Pacific Northwest, BPA includes an irrigation discount in the PF-85 and NR-85 rate schedules for this rate period. This discount is based on current circumstances. The issue of whether a discount will be continued will be addressed in BPA's next rate filing. A separate irrigation discount combined with less seasonal differentiation of the capacity rate is the best solution for the conflicting demands of the summer and winter customers. In addition,* [page 337] *BPA is willing to work with both irrigators and retail utilities with irrigation loads to improve the irrigators ' efficiency of electricity use. The irrigation discount will help irrigators during this time of economic instability in the farm sector.*

*No evidence on the record supports the establishment of an irrigation discount in the short run on economic efficiency grounds. However, the uncertainty of the economic health of the agriculture sector in the long run, coupled with the current financial hardship this sector is experiencing, has led BPA to develop an irrigation discount for this next rate period. Short-run irrigation demand for electricity on a regional basis is most likely inelastic; therefore, a discount may result in the recovery of less revenue during the rate period from this consumer sector. The amount of revenue loss to BPA will depend on the degree to which irrigation loads can be maintained with the discount.*

## Issue #2

*How large should the irrigation discount be?*

## Summary of Positions

In the initial rate proposal, BPA did not propose an irrigation discount. Peters, BPA, E-BPA-41, 1-2. In the Evaluation of the Record, BPA proposed reducing the summer energy rate during the April through August period by an amount equivalent to a 2 mill per kilowatt-hour reduction to the current PF-83 average summer rate. Evaluation, BPA, A-01, 287.

NIU prefers an irrigation rate that will allow the agriculture industry to maintain current levels of production and, if possible, to recover to the levels set several years ago. NIU points to the historical precedent of the pre-1974 Irrigation Discount, which was a 48 percent energy discount. Dawsey, NIU, E-NI-01, 11. NIU states that a 3-mill reduction from the PF-83 rate would send out a "rate stability signal" to irrigators. NIU contends that such a signal would help irrigators weather the difficult economic times they are facing. Jones, NIU, E-NI-04, 19.

ICUA wishes to maintain, and possibly reestablish, the Pacific Northwest's irrigation load. They state that if the wholesale power costs to irrigators were reduced to slightly below the PF-83 level, irrigation load decline might be curbed, and possibly even reversed. Rostberg, ICUA, E-IU-03R, 4-7.

## Evaluation of Positions and Decision

The recovery of irrigation load levels set several years ago is an overly ambitious and possibly unwise objective. The number of irrigated acres in the region grew during the 1970s at a rate of about 7 percent each year. McKusick, BPA, TR 3570. Recently, irrigation loads have declined without a corresponding reduction in acreage. It can therefore be assumed that some of [page 338] the reduced irrigation load reflects the various conservation measures that farmers have implemented to reduce water and energy use per acre. A rate reduction to recapture loads lost because of efficiency improvements clearly would not be appropriate.

The PF-85 summer capacity rate has been increased relative to the winter rate for reasons unrelated to irrigated agriculture. This increased summer rate is likely to contribute to the irrigation industry's current economic difficulty. A reduction of the average summer PF-85 rate to a level slightly below the average summer PF-83 rate could help reduce production costs. Independent of the importance of electricity in overall production costs, such a reduction could assist an irrigator during the current economic situation. NIU has requested a 3 mill per kilowatt-hour reduction from the PF-83 rate. That request received very little opposition during the rate hearings. A discount may have some long-term economic benefits to BPA. Irrigation loads may not decline as rapidly if some irrigators can be enabled to survive the current economic slump with a short-term energy discount. However, because an irrigation discount may result in less revenue from one class of customers in the short run, BPA has a responsibility to its other customers to limit the discount and also to constrain the period of time that it will be available. Therefore, BPA is reducing the PF-85 summer energy rate during the April through August period by 3.7 mills per kilowatt-hour, which is equivalent to a 2 mill per kilowatt-hour reduction from the current average summer PF-83 rate. This discount will be available to qualifying loads for the 27-month rate period.

## Issue #3

*How should an irrigation discount be structured?*

## Summary of Positions

In the Evaluation of the Record, BPA proposed that an irrigation discount be limited to the proportion of the utility's total load that is purchased or exchanged from BPA during the April-August period. Evaluation, BPA, A-01, 288-289.

NIU proposes that all benefits of its proposed summer seasonal rate be captured in the energy portion of the summer PF rate; the capacity component would remain the same as the PF rate. Qualifying loads would be separately metered. The utility would be required to pass through the rate benefit directly to the irrigators. Dawsey, NIU, E-NI-01, 10.

ICUA proposes that BPA credit the energy component of the PF bill each month by a flat mills per kilowatt-hour discount applied to qualifying irrigation load served by BPA during the previous month. Each utility would pass the flat mills per kilowatt-hour reduction directly to the irrigator in the form of a billing credit. Rostberg, ICUA, E-IU-03R, 6-7. ICUA also [page 339] requests that any form of rate relief should be retained for a "reasonable period of time" to allow irrigators to react and for BPA and the region to evaluate the results. Rostberg, ICUA, E-IU-03R, 6. NIU cites a 5-year period as appropriate in order to meet the objective of stabilizing irrigation demand over a period of time. Rostberg, ICUA, TR 4279.

**Evaluation of Positions**

NIU and ICUA state that an irrigation discount should apply to the energy portion of the PF rate and that the benefits should be passed through to the irrigator. Dawsey, NIU, E-NI-01, 10; Rostberg, ICUA, E-IU-03R, 6. BPA agrees with those positions.

BPA is concerned that a long term discount might encourage farmers to make capital investments that cannot be recouped at an undiscounted electricity rate. Therefore, BPA disagrees that a 5-year period is reasonable. This differs from BPA's position on the 5-year request from Hanna in that Hanna offered to make a particular investment in order to qualify for the 5-year provision. Irrigators should not count on this discount in the long run. The purpose of the discount is to maintain load during this time of economic instability in the farm sector. If the discount assists irrigators during the current short-run economic slump, BPA's irrigation load may not decline as much in the long run.

ICP suggests that the irrigation discount, as proposed by BPA in the Evaluation of the Record, be applied to the entire region's irrigation load, not just to that load served by purchases from BPA. They argue that since the sole purpose of the discount is to provide financial assistance, all irrigators in the region should receive the discount. Reply Brief, ICP, R-IC-01, 22-23. It is not true that financial assistance is the sole purpose of the discount. The purpose of the discount is to maintain irrigation as a BPA load. BPA is financing the irrigation discount from other customers' revenues and has a responsibility to its other customers to limit the amount of the discount. Extending the discount to non-BPA loads would not fulfill this responsibility. BPA customers would be subsidizing non-BPA customers under the ICP recommendation. BPA is, however, applying the irrigation discount to both the PF-85 and the NR-85 rates, so the discount will be available for irrigation load growth of the privately owned utilities when they purchase power from BPA under the NR-85 rate.

No party addressed the issue of whether a discount should be available for the irrigation loads of exchanging utilities. The Northwest Power Act provides that farm electric loads or uses are eligible to be exchanged under section 5(c)(1). By definition, however, these farm loads are "limited to the first 400 horsepower (HP) (cumulative) of farm irrigation and pumping loads during any monthly billing period. This 400 HP limit should include virtually all regional family farms and some corporate farms for the purposes of the section 5(c)(1) power exchange. Large corporate farms that do not qualify will be treated the same as IOU, commercial, and industrial customers." *Legislative History of the Pacific Northwest Electric Power Planning and Conservation Act*, page 78. It could be argued that the discount should not be [page 340] applied to exchange loads because an increase in those loads would increase BPA’s costs. However, since exchange loads served under the Priority Firm Power rate consist, in part, of irrigation loads and the discount is part of the Priority Firm rate, the discount will be applied to this load.

ICP states that BPA should specify the mechanism for implementing the discount proposed in the Evaluation while an exchanging utility is in deeming status. Reply Brief, ICP, R-IC-01, 23. Exchanged irrigation loads qualify for the irrigation discount because they are purchased at the PF rate. Currently, the average system cost of deeming utilities is compared to BPA's PF rate. If the average system cost is less than the PF rate, the utility is allowed to deem its average system cost to be equal to the PF rate. A deeming utility will not receive an exchange payment because of the irrigation discount. However, its deeming account will be affected.

Testimony on the seasonality of the discount is based on the rationale that irrigation is an offpeak load, thereby supporting the summer seasons as defined in the PF rate. Dawsey, NIU, E-NI-01, 10; Hittle, NIU, E-NI-01, 16; Rostberg, ICUA, E-IU-03R, 5. Irrigation season varies by production area and by individual crops' water requirements. The regional irrigation season is April-October, peaking in June-August. McKusick, BPA, E-BPA-44A3, 16. During the summer energy period, BPA is most likely to have surplus resources and least likely to have alternative markets for these surplus resources. Roghair, BPA, E-BPA-60R, Attachment 2, 10. Limiting an irrigation discount to April-August would cover almost all the irrigation season. Such a limitation would also reduce BPA's cost of implementing a discount.

NIU suggested that since the discount proposed by BPA in the Evaluation is based on economic hardship, not on seasonality considerations, the discount should be made available during all months in which substantial electricity use for irrigation occurs. NIU proposed adding September to the April-August period. Reply Brief, NIU, R-NI-WS-NE-01, 2. BPA considered the interest of irrigators with respect to all other customers when determining both the period and level of the irrigation discount. Irrigation load occurs during all months of the year and some method must be chosen to limit the impact of this discount on other customers. Thus, BPA limits the discount to the summer energy period, already designated as a lower cost period for BPA. Additionally, in the September-October period, irrigators have much greater flexibility to shift to offpeak use. Peters, BPA, E-BPA-41, 3-5; McKusick, BPA, E-BPA-44A2, 2.

**Decision**

*BPA applies an irrigation discount per kilowatt-hour to that portion of qualifying energy served by BPA during the April-August period. To qualify for the discount, energy purchased from BPA at either the PF-85 or NR-85 rate must be resold by the purchaser to its customers for the purpose of serving the irrigation and drainage pumping load on agricultural land. A proportional irrigation discount is available also to the qualifying irrigation portion of a utility's actual exchange load. Purchasers must certify that all such*
[page 341] *energy is resold solely for this purpose and that the discount is passed through in its entirety to the irrigation customer. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.*

*Those customers that generate their own power or purchase power from other sources also serve irrigators. Limiting the irrigation discount to the proportion of the utility's total load that is purchased at the PF rate or the NR rate ensures that non-BPA loads will not receive a discount which is funded by BPA customers. Only BPA's loads are eligible for the irrigation discount.*

**Issue #4**

*How should the revenue deficiency from an irrigation discount be recovered?*

**Summary of Positions**

NIU's proposed summer seasonal rate would increase the seasonality of the PF rate, further reducing the summer rate and increasing the winter rate. Dawsey, NIU, E-NI-01, 9.

ICUA, representing both summer and winter peaking preference customers, states that the inter-seasonality issue within the PF rate should not be exacerbated. ICUA proposes a intra-seasonal solution. Their methodology would not change the revenue requirement for the PF class or for either of the respective seasons. If irrigation-related consumption were to increase in response to a discounted rate, the additional revenue might be sufficient to cover the cost of the discount. If BPA were to expect unrecovered revenues, these revenues would be recovered from other PF summer season loads. Rostberg, ICUA, E-IU-03R, 2-6.

**Evaluation of Positions and Decision**

BPA opposes any recovery of a revenue deficiency from a summer irrigation discount by further increasing the seasonality of the PF rate. As discussed in Issue #I, BPA faces the possibility of decreases in revenues from winter sales because of the high winter capacity rates.

BPA recognizes the importance of irrigated agriculture to the region. However, in order to maximize the regional benefits of implementing an irrigation discount, BPA needs to minimize the cost of the discount to its other customers. Therefore, BPA proposes to recover any revenue deficiency resulting from an irrigation discount from all other sales. The amount of the discount ($12.5 million) is subtracted from the nonfirm energy revenue credit in the rate design process. This will have no effect on the seasonality of the rates and will spread the cost of the discount to all classes.

[page 342]

## K. Adjustment Clauses

In recent years BPA has experienced serious revenue recovery problems. In its initial proposal and in testimony, BPA proposed the use of less than average water conditions to compensate for the revenue risks inherent in the uncertainty of forecasting both firm loads and saleable nonfirm energy. To compensate for unanticipated changes in costs, BPA continues to rely on the Supply System Adjustment Clause and Exchange Adjustment Clause. To compensate for the anticipated displacement of firm purchases by the generating utilities, BPA continues to rely on the availability charge. Parties proposed several alternatives to deal with the problem of revenue uncertainty.

**Issue #1**

*Should BPA adopt an adjustment clause or clauses to compensate for changes in revenues and sales from those forecast?*

**Summary of Positions**

PGP proposes a Load Adjustment Clause (LAC) that would trigger a rate adjustment in the next fiscal year whenever a customer class load change led to a change of over 2 percent in BPA's annual revenues. The proposed LAC would not apply to changes in residential exchange loads (which are already addressed by the Exchange Adjustment Clause), and would replace the need for the availability charge component of the Priority Firm Power rate. A credit of 7 mills per kilowatt-hour would be applied to recognize actual revenues earned in the nonfirm energy market by selling the firm power that resulted from the lower loads. Winterfeld and Opatrny, PGP, E-PG-08, 2-8. The termination of a DSI contract would not be handled in the LAC. Winterfeld and Opatrny, PGP, E-PG-08, 9.

PGP also proposes that BPA implement a Water Adjustment Clause (WAC), which would trigger a rate adjustment in the next fiscal year if actual nonfirm energy generation differed by more than 5 percent from projected nonfirm energy generation (40 year average). The adjustment for the WAC would be spread over 10 months in the following fiscal year. Winterfeld and Opatrny, PGP, E-PG-08, 11-12.

WPAG proposes that BPA adopt an Excess Revenue Adjustment Clause (ERAC) in conjunction with the use of 1939 water conditions as an appropriate method to rebate any overcollection of revenues to customers and still assure revenue recovery. The ERAC would trigger when total nonfirm energy and priority firm power revenues differ from the rate filing forecast. Any over- or under-collection would result in a rebate or surcharge to purchases made at the PF, CF, and NR rate schedules. The WPAG position was later modified to include changes in DSI revenues as well. Reply Brief, WPAG, R-WA-01, 21. The surcharges or rebates would be calculated after June 30 of each year and no adjustments would be made if the calculated adjustment were less than
[page 343] 1 percent of the customer class revenue requirements. Hutchison, Muller, Saleba, and Schneider, WPAG, E-WA-01, 21-24.

The DSIs endorse a Net Revenue Adjustment Clause (NRAC) that they argue would provide BPA with stable revenues. Rate stability and predictability would be supported. The adjustment clause would permit annual rate adjustments and timely interest and amortization repayments to the Treasury. The adjustment would apply to all adjustable rate schedules. Schoenbeck, DSI, E-DS-9, 2-4.

**Evaluation of Positions**

BPA notes several shortcomings of the LAC: (1 the retrospective nature of the proposed adjustment clause would not improve BPA's near-term ability to meet its financial commitments to the U.S. Treasury; (2) the 2 percent trigger on total revenues may not allow the clause to be implemented; and (3) the clause would place an unreasonable administrative burden on the agency. The prospect of assigning responsibility for revenue shortfalls to particular customer classes may aggravate rather than solve a revenue recovery problem. Wedlund, BPA, E-BPA-63R, 5-6. Thus, PGP's LAC appears to be an attempt to delay or actually avoid dealing with the revenue recovery problem that BPA faces. Wedlund, BPA, E-BPA-63R, 5. Two percent of total BPA revenues (the trigger) represents approximately $40 million. Given that two classes would be covered by this clause. BPA would have to sustain firm revenue losses of more than $80 million before implementing the proposed LAC. This would seriously impair BPA’s ability to meet its financial obligations to the U.S. Treasury.

BPA has found several weaknesses in the proposed water and excess revenue adjustment clauses: (1) they would not improve BPA's ability to make timely payments to the Treasury; (2) they would impose an added administrative burden on BPA; and (3) they could require refunds even if BPA were unable to meet its scheduled payments to the Treasury. Wedlund, BPA, E-BPA-63R, 5-7. PGP's WAC depends on the NFRAP computer model. Data collection for the WAC would be difficult since the NFRAP requires data on actual operations in addition to Federal nonfirm energy generation. Wedlund, BPA, E-BPA-63R, 6-7. Some of this information is not available on June 30. Adjusting power rates after all required operational data have been obtained and a reasonable public comment period held would prove prohibitively time-consuming. PGP equates the WAC to a Fuel Adjustment Clause (FAC). Winterfeld and Opatrny, PGP, E-PG-08, 11. This is not accurate. An FAC is related to differences between projected and actual costs, while the proposed WAC is not dependent at all on costs. Wedlund, BPA, E-BPA-63R, 6. It is thus not clear how the WAC can be compared to the type of FAC that is common among thermal systems.

In the Evaluation of the Record, BPA addresses two technical problems specific to the ERAC. These are the ERAC's failure to consider DSI load underruns in its calculation and its apparent ambiguity regarding the inclusion of residential exchange loads. BPA, A-01, 241. WPAG responds that the ERAC should be expanded to include DSI load underruns, since the IP-85
 rate will receive an excess revenue credit. WPAG adds that the ERAC is not designed to consider exchange cost variances, since these are addressed in BPA's Exchange Adjustment Clause. Reply Brief, WPAG, R-WA-01, 21. However, WPAG does not answer BPA's criticism that the ERAC may provide rebates to customers when rebates are not warranted. Wedlund, BPA E-BPA-63R, 7-9; BPA, A-01, 241. Even though changes in DSI loads would be considered, the proposal still does not consider differences between total actual and projected revenues and would impose additional administrative burdens. Wedlund, BPA, E-BPA-63R, 5-7.

The DSIs' proposed NRAC includes a tolerance band (or trigger) that is overly wide ($50 million). The NRAC also would impose significant administrative burdens. Wedlund, BPA, E-BPA-63R, 8. The NRAC would provide no immediate benefit in helping to assure that BPA's payments to the U.S. Treasury are made in a timely manner. The NRAC appears to provide nothing more than a set of guidelines for changes in rates. Wedlund, BPA, E-BPA-63R, 8.

There are several problems generic to all these proposals, and which BPA's package of revenue stability measures attempts to avoid. First, there is the question of timing. Of those clauses that recommended specific procedures, all contained lags of at least several months between determining that a deficiency had actually occurred and recovering that deficit from other sales. In the worst case, the WAC, nonfirm energy production could fall below average or below 1939 water at the beginning of an operating year but any associated revenue deficiency would not be completely recovered until 22 months later. This is an unacceptably long delay for an adjustment clause. BPA's use of 1939 water provides a much greater assurance that Treasury payments will be made in a timely manner. Second, despite claims to the contrary, there are serious computational problems associated with any adjustment based on load underruns or overruns. Reply Brief, PGP, R-PG-01, 32-34. There are over one hundred PF customers, some of whose bills are not finalized for several months. Adjustments based on estimated or preliminary data would themselves have to be adjusted again several months later. This would be administratively excessive given the unquantified potential benefits. Load underruns by some firm customers are not the only source of potential revenue difficulties. BPA revenues from surplus firm power and nonfirm energy sales also represent a source of substantial uncertainty. Incorporating market considerations into an adjustment clause that would adequately protect the interests of the Treasury and BPA's customers would absorb considerable resources for no apparent benefit. Finally, several theories allocating the potential underrecovery have been proposed, with no clear justifications.

PGP's Load Adjustment Clause would attempt to assign specific responsibility to the PF and IP classes for the whole rate period, not withstanding load underruns or overruns. Cost allocation to a particular class is an element of prospective rate design. It is not equivalent to the assignment of a revenue requirement to that class. The outcome of assigning a revenue requirement to customer classes may aggravate rather than solve BPA's [page 345] revenue recovery problems. Wedlund, BPA, E-BPA-63R, 5-6. The prospect of retroactive rate adjustments in order to avoid making a geater [sic] than projected payment to the Treasury will not help to stabilize BPA's rates or make them more understandable. Furthermore, it will tend to confirm doubts about BPA's efforts to improve its creditworthiness.

Last, BPA's use of 1939 water, the two adjustment clauses, and the availability charge all provide for timely payments of Treasury obligations because they either provide a monthly ex ante enhancement of expected revenues (1939 water and the availability charge) or are tied to specific cost elements (the adjustment clauses). The use of 1939 water conditions is a remedy for more than just the uncertainty in PF loads and water conditions. The Revenue Uncertainty Analysis dealt with the revenue impact of changes in IP, PF, and NF sales.

**Decision**

*BPA is not adopting the various adjustment clauses proposed by the parties. The adjustment clause proposals based on loads would not provide BPA an increased assurance of meeting its financial obligations to the U.S. Treasury in a timely manner. The adjustment clause proposals could not be administered as easily as the Supply System Adjustment Clause or the Exchange Adjustment Clause. Changes in costs have a direct effect on BPA's ability to schedule payments to the Treasury, so adjustment clauses to compensate for potentially large changes in costs are* *justifiable. To analyze the actual effects of changes in loads and water conditions would impose substantial administrative burdens and would be potentially divisive. Changes in loads have only an indirect effect on BPA's ability to meet its financial obligations.*

*A myriad of adjustment clauses is not a substitute for developing rates that will satisfy BPA's financial obligations. BPA's risk of not making its projected payments to the Treasury on a timely basis is adequately addressed by developing rates based on 1939 water conditions. The proposed adjustment clauses send a different signal. The proposed adjustment clauses signal the Federal Energy Regulatory Commission and the Treasury that BPA and its customers expect the Treasury to absorb the risks of underpayments but not the benefit from overpayments. This is not a financially responsible way to deal with creditors. BPA has not made projected payments to the Treasury in recent years, for a variety of reasons. It would be imprudent to adopt adjustment clauses which send a signal that indicates BPA will not be allowed to exceed its projected repayments.*

**<u>Issue #2</u>**

*Is the allocation pursuant to the Exchange and Supply System Adjustment Clauses correct?*
[page 346]

**<u>Summary of Positions</u>**

In BPA's initial proposal, the IP-85 share of a possible rate adjustment from the application of the Exchange and Supply System Adjustment Clauses was adjusted to maintain the rate relationship with the PF-85 rate, as required by section 7(c)(2) of the Northwest Power Act. The difference between the IP-85 allocated share of total exchange and Supply System costs and the adjusted share was apportioned to the other rate classes according to the allocation of the 7(c)(2) adjustment in the Rate Analysis Model. BPA, E-BPA-08, 48-50. The DSIs assert that the IP-85 customers should not be assigned any share of surcharges or rebates resulting from the implementation of BPA's adjustment clauses, to the extent that the IP-85 rate is determined by the rate floor. Initial Brief, DSI, B-DS-01, 94-95; Reply Brief, DSI, R-DS-01, 61-62.

In addition, BPA exempted the SP-85 rate from the Exchange and Supply System Adjustment Clauses in its initial proposal, because SP-85 is a market-based rate. The SP-85 share of exchange and Supply System costs was reassigned to the other customer classes. BPA, E-BPA-08, 49. The DSIs maintain that BPA should not reassign SP-85 costs to the other customer classes. Schoenbeck, DSI, E-DS-09, 2-4, 8.

**<u>Evaluation of Positions and Decision</u>**

The DSIs argue that the rate level is higher when the rate floor provision is in effect than when IP-85 is fixed by the margin combined with the PF-85 rate. In this circumstance, the DSIs propose that their participation in the Exchange and Supply System Adjustment Clauses be reconsidered by BPA. According to the DSIs, it is inappropriate that they be required to pay for exchange and Supply System costs which, had they been accurately forecast in the rates, still would have left the IP-85 rate at the floor. Initial Brief, DSI, B-DS-01, 94. The DSIs recommend that they be exempt from participation in the adjustment clauses. Surcharges and rebates assignable to the DSIs should be reallocated to the other eligible customer classes.

Portions of any surcharges assignable to the DSIs that would lift the IP-85 rate above the rate floor should be absorbed by BPA. Reply Brief, DSI, R-DS-01, 62, Attachments 2, 3.

The DSIs are correct that their participation in the Exchange and Supply System Adjustment Clauses should be reconsidered. The IP-85 rate is set at the rate floor, and the average rate level is 1.7 mills above the 7(c)(2) rate. BPA, FS-BPA-05, 145. The IP-85 rate is projected to recover $39.8 million more than it would had it been set at the mark-up rate (PF plus margin). Accordingly, the Industrial Power customers are exempt from the adjustment clauses during the 1985 rate period. Exchange and Supply System adjustments allocable to the DSIs are apportioned to the eligible customer classes in proportion to the 7(c)(2) adjustment in the Rate Analysis Model.

The DSIs also argue that BPA's initial proposal inappropriately collects 100% of the net exchange cost adjustment from customer classes that are responsible for only 79 percent of the exchange costs. Schoenbeck, DSIs, E-DS-09, 2. The DSIs would therefore exclude from the adjustment clause
[page 347] calculation that portion of net exchange costs allocable to the exempted surplus power class. Schoenbeck, DSI, E-DS-09, 8. BPA recognizes that the exemption of both the DSIs and the surplus power customer classes puts an added burden on the remaining customer classes that are subject to BPA's adjustment clauses. Accordingly, BPA will share the risks and benefits with these customer classes by accepting this recommendation by the DSIs and absorbing the share of exchange and Supply System adjustments assignable to surplus power.

## L. General Rate Schedule Provisions

**Issue #1**

*Should there be a diversity charge?*

**Summary of Positions**

BPA includes section III.C.5 of the GRSPs, Coincidental Billing Adjustment, "to clarify billing procedures for customers who are billed on a coincidental demand basis." Peters, BPA, E-BPA-41, 14. This section is included in the GRSPs to specify billing procedures if a customer's present diversity charge were to be re-evaluated at some future date, and to state BPA billing policy for those customers who are currently assessed a diversity charge. The initially proposed language for this section was confusing in its treatment of coincidentally billed consumers, and BPA presented a clarification in addendum. Peters, BPA, E-BPA-41A, 2.

WPAG opposes implementation of the proposed diversity charge. WPAG states that "[a] number of coincidentally billed utilities have provisions in their power sales contracts with Bonneville which explicitly state the level of diversity charge which will be imposed. The proposed diversity charge will likely be in conflict with these contractual provisions." Hutchison, et al., WPAG, E-WA-01, 70.

**Evaluation of Positions and Decision**

WPAG cites no specific examples to support its position that the proposed diversity charge is in conflict with specific power sales contract provisions. Section III.C.5 of the GRSPs states, "a charge shall be assessed for the diversity among the purchaser's coincidentally-billed points of delivery unless BPA elects to waive such charge in whole or in part." BPA, E-BPA-08, 294. This wording was retained in addendum testimony presented on this section of the GRSPs. Peters, BPA, E-BPA-41A, 2. BPA is not proposing any changes to existing waivers at this time. For the purpose of clarification, an additional sentence has been added to section III.C.5 of the GRSPs, which states: "If a diversity charge is specified in a purchaser's power sales contract, that charge shall be applied."

[page 348]

**<u>Issue #2</u>**

*Should an outage credit for energy be granted at the rate of Unauthorized Increase?*

**<u>Summary of Positions</u>**

BPA has proposed section III.C.2 of the GRSPs, Outage Adjustment, to clarify billing procedures used in the application of section I.B.7 of the General Contract Provisions (GCPs), Reducing Charges for interruptions. Peters, BPA, E-BPA-41, 14. The outage credit adjustment is based on the length of the outage and the level of billing demand for the affected point of delivery.

PNGC argues that the proposed methodology for issuing outage credits does not adequately compensate the utility and its consumers for costs incurred as a result of interruptions. They propose that Bonneville "retain the demand reduction provided for in the initial proposal and, in addition, provide an energy credit to the utility based on the rate for unauthorized increase." Johnson, PNGC, E-PN-01, 3.

**<u>Evaluation of Positions and Decision</u>**

The purpose of the outage credit is to ensure that BPA does not charge for a service not provided. The Unauthorized Increase Charge, on the other hand, reflects an additional cost to BPA, not to the purchasing utility. PNGC contends that use of the unauthorized increase charge in the calculation of outage credits is appropriate because that charge is "calculated by estimating the variable costs of a combustion turbine," Johnson, PNGC, E-PN-01, 3, and that use of this charge would compensate utilities and their consumers for the variable costs incurred as a result of providing back-up generation. The purpose of the credit is not to compensate utilities for such costs. Therefore, the outage credits do not provide for the cost of backup generation

**<u>Issue #3</u>**

*Should the disputed billing provision be changed?*

**<u>Summary of Positions</u>**

BPA proposed section VI.G.5 of the GRSPs, Disputed Billings, to state payment procedures. The issue of arbitration is addressed in the GCPs, section I.H.32, and the General Wheeling Provisions (GWPs), section 20, Dispute Resolution and Arbitration.

The ICP claims that "Bonneville does not investigate and attempt to reach agreement with its customers in order to resolve disputed billings." Lauckhart, ICP, E-IC-05, 6. The ICP further states that the existing section of the GRSPs on Disputed Billings does not "provide any means for resolving such disputes." Lauckhart, ICP, E-IC-05, 6.

[page 349]

**Evaluation of Positions and Decision**

The ICP appears to be making two arguments. First, the ICP claims that BPA does not actively pursue resolution of disputed billings. However, the ICP presents no evidence of disputes that BPA has not actively attempted to resolve. Second, ICP states that section VI.G.5 of the GRSPs should be expanded to address this issue. The ICP argues that this provision "should expressly provide that Bonneville will attempt to resolve the disputed billing with the utility involved and, if the dispute is not resolved, that Bonneville will offer to enter into an agreement with the utility to arbitrate the issues of fact underlying the dispute." Initial Brief, ICP, B-IC-01, 58. Inclusion of this language in the GRSPs would serve no purpose other than to duplicate an existing BPA policy that is clearly stated in section I.H.32 of the GCPs and section 20 of the GWPs.

The ICP assertion that BPA does not resolve billing disputes is unfounded. Their further contention that section VI.G.5 of the GRSPs should address this issue is inappropriate, as this issue is already addressed in the GCPs. The purpose of the GRSPs is to expand upon and clarify BPA policy without unnecessary duplication of other contractual agreements. No additional language to address this issue is included in the GRSPs.

**Issue #4**

*Should the Low Density Discount (LDD) eligibility criteria be changed?*

**Summary of Positions**

BPA proposed a change to section III.C.3.b. of the GRSPs, Eligibility Criteria, as follows:

From: "the purchaser must serve as an electric utility offering power for resale;"
To: "the purchaser must serve as an electric utility offering power for sale to ultimate consumers;"

This change was proposed to clarify existing policy, and was not intended to affect the LDD eligibility of any customer. BPA, E-BPA-08, 292. PNGC expresses concern that this wording would affect future determinations of LDD eligibility. Initial Brief, PNGC, B-PN-01, 11.

**Evaluation of Positions and Decision**

BPA presented this change in GRSP wording only in order to clarify existing policy. PNGC points out that "[t]he BPA power sales contracts (GCP 55) in fact contemplate that some BPA customers will resell BPA power at wholesale to other utilities." Initial Brief, PNGC, B-PN-01, 11.

[page 350]

BPA agrees that its proposed GRSP wording could inadvertently and incorrectly exclude utilities from the LDD. This effect is unintended. This language in the GRSPs remains unchanged from its current version.

[page 351]

## IX. TRANSMISSION RATE DESIGN STUDY

### A. Introduction

Six transmission rates are subject to this rate adjustment proceeding. The Formula Power Transmission (FPT-85) and integration of Resources (IR-85) rate schedules apply to firm wheeling transactions on BPA's Network transmission segment. For two contracts, the FPT-85 rate also applies to firm wheeling on the Southern Intertie. The Southern Intertie (IS-85) rate, an energy based rate, is applicable to all nonfirm wheeling on the Southern Intertie except for wheeling under the Exportable Agreement at the ET-2 rate, which is being extended. The Northern Intertie (IN-85) and Eastern Intertie (IE-85) rates are also energy based and are applicable to nonfirm wheeling on their respective intertie segments. The Energy Transmission (ET-85) rate is available for nonfirm use on the Network segment.

The ET-2 and UFT-2 rate schedules referenced in existing agreements are not subject to adjustment by BPA at this time, and are therefore continued for such agreements. The TGT-1 and UFT-83 rate schedules are continued because they contain internal adjustment features, eliminating the need for a rate schedule adjustment. The FPT-83.3 rate schedule is contractually limited to rate level changes every 3 years and therefore cannot be revised until July 1987.

### B. Intertie Wheeling Projections

**Issue #1**

*What should the Northern Intertie wheeling projections be?*

**Summary of Positions**

In BPA's initial proposal, projected wheeling energy on the Northern Intertie was developed on the basis of Canadian sales to California and to the Northwest. Canadian sales to California were projected in the NFRAP. These projections were consistent with the projected Canadian energy wheeled on the Southern Intertie. Canadian sales to the Northwest were based on FY 83 actual loads. Chang, BPA, E-BPA-42S, 2, 3.

BC Hydro recommends the use of average historical sales, in addition to a credit adjustment for the Skagit Treaty, which would reduce the IN rate. BC Hydro, letter dated January 29, 1985.

LADWP asserts that use of FY 83 loads for projections of Canadian sales to PNW utilities significantly understates the sales that would occur in an
[page 352] average water year, since FY 83 had much higher than average runoffs and PNW utilities had reduced demand for Canadian energy. Parmesano and Whitney, LADWP, E-LA-01, 20.

To accomodate [sic] LADWP's concern about use of FY 83 sales, BPA's supplemental testimony proposed to use an average of most recently experienced sales from Canada (FY 82-FY 84) for in projections. Chang, BPA, E-BPA-425, 2.

**Evaluation of Positions**

Based on the revised NFRAP forecast of non-Federal sales over the Southern Intertie, the projected wheeling load over the Northern Intertie would have declined to 140 aMW if the methodology in BPA's initial proposal had been retained. When compared to recent experience, this projection appears unreasonably low. Chang, BPA, E-BPA-425, 3. In rebuttal testimony BPA proposed that obligation return energy, reduced for capacity/energy exchange contracts which expire during the test year, should be included in the development of the IN rate. It appears that BC Hydro's figures for developing expected obligation return energy did not take the contract expirations into consideration. These adjustments for obligation return energy account for the difference between the projected use in the initial proposal and rebuttal testimony and result in a lower rate. Chang, BPA, E-BPA-59R, 2, Attachment 1; TR 4219. In a subsequent comment, BC Hydro agrees that if they had taken into account expiration of the obligation contracts the expected obligation sales would indeed decrease. They claim this would have been offset in part by additional sales in the total market, especially since they have entered the boiler displacement market and now expect their sales to the Pacific Northwest to increase. BC Hydro, letter dated April 1, 1985. However, the BC Hydro figures were submitted through the public comment process and have not been subject to discovery or cross examination; they must be viewed with this limitation in mind.

In addition to an Increase in projected IN sales, BC Hydro proposes a credit of approximately $0.4 million/year for wheeling of Skagit Treaty energy to Seattle. This proposal, however, overlooks the Treaty provision which deems that transmission would assume origin from within the State of Washington. Article V of the Treaty states that "the rate imposed by BPA, or its successor agency, for the transmission of power from British Columbia to Seattle pursuant to the Agreement shall be no greater than if the power were generated, and transmitted on the Federal Columbia River Power System, wholly within the State of Washington." Treatment of High Ross replacement power in the TRDS is intended to reflect this provision. It therefore is deemed to be an IR transaction using the Network, but not the Northern Intertie segment, and is included only in development of the IR rate. Chang, BPA, E-BPA-42, 16.

Projections of future wheeling loads on the Northern Intertie are speculative because they are sensitive to water conditions and indirectly affected by the Near Term Intertie Access Policy. The Policy provides increased access to the Southern Intertie for Canadian utilities, although no agreements have yet been reached. Chang, BPA, E-BPA-42S, 3. The projections [page 353] reflect estimated wheeling loads based on the best available information. BPA, E-BPA-09, 12.

**Decision**

*The Northern Intertie wheeling projections shown in E-BPA-59R, Attachment 1, based on historical sales plus forecasted obligation return energy, have been documented and are verified to be appropriate. High Ross replacement power wheeling under the Skagit Treaty is deemed to be an IR transaction; revenue from that transaction is therefore not credited to the Northern Intertie revenue requirement.*

**Issue #2**

*What should the Southern Intertie wheeling projections be?*

**Note**

This issue is addressed in Chapter V, Section C, Transmission Costs.

## C. ET Rate Design Methodology

**Issue #1**

*How should the ET-85 rate be determined?*

**Summary of Positions**

As in prior rate filings, the ET-85 rate approximates the average cost per kilowatt-hour for firm wheeling service. The method used to develop the ET-85 rate is the same method used to develop ET-83 and the energy charge in the IR-85 rate. BPA, E-BPA-09, 30.

SCE acknowledges that the COSA appropriately classifies all transmission-related costs to the capacity component, but argues that the classification was altered when applied to transmission rates and therefore results in inconsistent rate design methods. A more realistic rate design, according to SCE, would be to establish the ET-85 rate at the level of the IR energy component and recover the difference in revenue requirement from the IR demand component. SCE asserts that BPA's proposed nonfirm transmission rate is higher than its firm transmission rate and uses the same facilities as its firm transmission rate, but without capacity. SCE also claims that BPA has not built facilities to provide ET service and will not expend dollars to provide nonfirm transmission service. Hull, SCE, E-CE-01A, V-2, V-3.
[page 354]

**Evaluation of Positions**

SCE claims that facilities have not been built to provide ET-85 service; therefore, there is no basis for assigning capacity-related transmission costs to the ET-85 rate. Hull, SCE, E-CE-01A, V-2. BPA counters that nonfirm transactions are considered when planning the transmission system. BPA plans the Network segment to support the capability of the Southern Intertie for both firm and nonfirm power. While BPA cannot identify specific facilities installed to provide nonfirm transmission service, nonfirm transactions have contributed to the need for transmission construction. Chang, BPA, E-BPA-59R, 5-7.

Incidental wheeling customers have historically received the same quality of service as firm wheeling customers. BPA has not refused ET service due to lack of available capacity within the Northwest. Transmission limitations on the BPA system are confined to the extraregional tie lines. Additionally, rate schedule language with reference to availability ties BPA's obligation to provide service over a period of time to the customer's commitment to pay for that service. Therefore, it is appropriate to include in the ET-85 rate both capacity and energy costs for incidental wheeling on the Network. Also, it should not cost less for a nonfirm customer to use the Network to access the Intertie than for a firm customer who pays a combination of IR demand and energy charges. For utilities without firm wheeling contracts, incidental wheeling will cost the same as the average IR rate. Chang, BPA, E-BPA-59R, 5, 6. The assertion that the ET-85 rate is higher than the firm transmission rate for services received is not supportable. Firm wheeling customers pay contract demand charges to reserve facilities, whether used or not. ET customers, however, receive high quality service benefits from those facilities, but pay only for energy wheeled.

**Decision**

*The ET-85 rate is calculated to be equal to the average cost of firm Network transmission. This rate is equitable in relation to BPA's other rates for transmission service.*

**D. IS Rate Design Methodology**

**Issue #1**

*Should the PP&L half mill credit be included in the IS rate design methodology?*

**Summary of Positions**

PP&L receives a 0.5 mill/kWh credit for incidental wheeling on the Southern Intertie, under the Vantage Agreement. The initial proposal treated this credit in the design of the is rate as a revenue deficiency. Chang, BPA, E-BPA-42, 13.

[page 355]

ICP contends that inclusion of the half mill credit to PP&L is not proper in development of the IS rate. Wilson, PP&L, E-IC-09, 10-11. ICP also notes that to the extent the credit is a cost item in COSA, it may not be added as a rate design adjustment. Nelson, ICP, TR 4230.

**Evaluation of Positions and Decision**

The ICP argues that because the credit is given in recognition of payments made under an agreement for Network wheeling, it is improper for BPA to collect such payments a second time. Wilson, ICP, E-ICP-09, 11. The PP&L half mill credit does not appear in COSA. The credit results in a reduction of revenues from the sales that are used to determine the IS rate. The resulting deficiency in revenues must be charged to an adjustable wheeling rate. Customers who are provided firm wheeling on the Network should pay for the half mill deficiency because PP&L's mid-Columbia resource associated with the Vantage Agreement must be used in the development of FPT and IR rates. The contract contributes to both the allocation to FPT/IR and the denominators of these rates. Chang, BPA, E-BPA-59R, 7, 8. Because the credit is not a cost item, there is no charge related to it for which a double payment is made.

It is appropriate to incorporate the half mill credit in the calculation of the Network firm wheeling rates and not in the IS rate.

**<u>Issue #2</u>**

*Should the Southern Intertie be separated into AC and DC portions for ratemaking purposes?*

**<u>Summary of Positions</u>**

In the initial proposal BPA included the costs of both the AC and DC facilities in the development of the Southern Intertie rate. Gilman, BPA, E-BPA-25, 2, Attachment 1.

LADWP suggests that BPA create separate transmission segments for the AC and DC Southern Intertie facilities for costing and ratemaking purposes. Parmesano and Whitney, LADWP, E-LA-01, 22.

**<u>Evaluation of Positions</u>**

LADWP's suggestion assumes that costs and uses of the AC and DC segments can be separately identified and that treating the Southern Intertie as two segments would permit more precise cost-based rates to be developed. However, in projecting use of the lines to determine rates it would not be feasible to separate sales by line due to uncertain identity of the buying utility and the fact that some California utilities have access to both lines. The Intertie lines have historically been operated as one system serving the California market. The lines are nearly parallel and their length is essentially the same. From the Northwest perspective, both lines serve the same purpose of transferring power from the Northwest to the California border. Even if
[page 356] subsegmentation were feasible, it would not be appropriate from a ratemaking standpoint. Use of different rates for the lines might favor use of one line over the other, which could lead to lower operating efficiency in the form of higher losses and unused capability. Chang, BPA, E-BPA-59R, 8. Planned expansion of the AC Intertie to 4800 MW, beyond this rate period, may warrant further evaluation of separate AC and DC segments, particularly if any significant change in Intertie use should occur.

**<u>Decision</u>**

*The AC and DC portions of the Intertie are operated as a single system. and it is not appropriate or feasible to separate them for ratemaking purposes.*

**E. FPT Rate Design Methodology**

**Issue #1**

*What is the appropriate method to develop the Southern Intertie component of the FPT rate?*

**Summary of Positions**

The FPT Southern Intertie component charge currently applies to only two WWP contracts (#79101 and #90185). As part of the FPT class, the Southern Intertie component is constrained by the same percentage as the other FPT components to reduce total FPT revenues to the COSA allocated cost. Chang, BPA, TR 4201; E-BPA-59R, 4. The Southern Intertie component is based on use of the transformation and transmission facilities on that intertie segment. BPA, E-BPA-09, 28.

ICP argues that an Inconsistency in the way BPA calculates the FPT rate for firm non-Federal wheeling on the Southern Intertie results in an overcollection of revenues. Felgenhauer, ICP, E-IC-08S, 2, 3; Reply Brief, ICP, R-IC-01, 27.

**Evaluation of Positions**

According to the ICP, BPA's calculation for the firm wheeling revenue requirement on the Southern Intertie results in an overcollection of revenues. ICP claims this arises from application of a single "constrained component" to both the Main Grid transmission and the Southern Intertie. ICP claims that this is inappropriate because there is a diversity between the Main Grid and the Intertie. Felgenhauer, ICP, E-IC-08S, 2, 3; Reply Brief, ICP, R-IC-01, 29. The ICP recommends that the rate be calculated by dividing the revenue requirement for non-Federal firm Southern Intertie wheeling by the total transmission contract demand for the two WWP contracts. Felgenhauer, ICP, E-IC-08S, 3. This would result in an FPT rate of $2.71/kW year for the Southern Intertie component. Further, contractual provisions requiring BPA's [page 357] method of calculation, such as Contracts #79101 and #90185, should be officially acknowledged by the Administrator. Initial Brief, ICP, B-IC-01, 54, 56. The original WWP Contract #79101 was developed by the formula power method including its Intertie component. Subsequent amendments to Contract #79101 and the later Contract #90185 also reference the FPT rate schedule.

The traditional formula power concept that identifies specific facilities and rate factors for facility types evolved from the formula power transmission agreements negotiated prior to the 1974 Transmission Act. These rate factors are the basis for the current FPT rate schedules. Chang, BPA, E-BPA-42, 2; E-BPA-09, 4, 7. In developing the rate, BPA attempts to be consistent with historical contractual requirements in following the formula power method. However, in this proposal, the allocation is scaled down to the total FPT revenue requirement in the COSA.

There are two principal reasons why the revenue requirement derived from the COSA differs from projected revenues from the unconstrained FPT-85 rate: (1) revenues from NF-85 and ET-85 sales are not credited against the annual costs used to derive the unconstrained FPT rate; and

(2) the 12 CP method for cost allocation used in the COSA, to allocate costs between Federal and non-Federal power, differs from the FPT rate design method of deriving a unit cost per megawatt or per MW-mile. BPA, E-BPA-09, 25; BPA, 1981 Rates ROD, VIII-4 through VIII-6. The FPT method for the Intertie component is the unit cost per kilowatt in the test year, resulting in an unconstrained rate. In the proposal, as in the 1981 and 1983 rate filings, this rate is constrained by the same percentage as the other FPT components to provide FPT revenues equal to the FPT revenue requirement. It should be noted that the unconstrained method and the resulting unit cost of the Intertie could be the appropriate rate for the older WWP contract (#79101) because the credit provisions of this agreement are comparable to ownership rights.

The BPA proposed method recognizes diversity between the Intertie and the Network. The 12 CP allocators for these two segments are developed separately. BPA, E-BPA-01, 33. The peak responsibility method recognizes that the Intertie is dominated by nonfirm use. The two WWP contracts are now allocated costs based on 76 MW (1.3 percent) of coincidental use out of a total Intertie coincidental use of 5700 MW. The allocation percentage of Intertie cost for these contracts was over 4 percent in the 1983 filing, because separate coincidence factors for the Intertie and the Network had not yet been developed.

**Decision**

*As in the initial proposal, the Intertie component of the FPT rate is appropriately developed using the uniform FPT constraining ratio. The methodology proposed by WWP would incorrectly provide an additional recognition of diversity between the Network and the Intertie. For purposes of rate continuity, an FPT rate method with a single constraining factor is adopted for the Southern Intertie component.*

[page 358]

**F. Short Distance Wheeling**

**Issue #1**

*Should the FPT rate be available, in addition to the IR rate, for short distance wheeling?*

**Summary of Positions**

The IR rate schedule provides a discount to the demand charge in the event that power integrate data point of interconnection uses FCRTS facilities for less than 75 circuit miles. This is intended to prevent an undesirable incentive for wheeling customers to construct short distance parallel lines to avoid BPA's demand charge. Chang, BPA, E-BPA-42, 11.

Cowlitz County PUD argues that the FPT rate should be used in place of the IR short distance discount for firm transmission service involving distances less than 75 circuit miles. Smith, Cowlitz, E-CO-01R, 1-3.

PGP suggests that all customers of BPA should have the choice of entering into contracts with BPA under any of the available transmission contract options. Initial Brief, PGP, B-PG-01, 28.

**Evaluation of Positions**

The "postage stamp" design of the IR rate represents a change from BPA's formula power contracts. Specific facilities are not identified and full use of the integrated Network and access to the FCRTS are provided. Necessary compromises were made in the rate design to recognize the wheeling transactions that use fewer facilities. Because a postage stamp rate places a relatively high revenue burden on short distance transactions and could result in an undesirable incentive to construct short distance parallel lines, BPA implemented a short distance exception to the IR demand charge, and continues to utilize the use-of-facilities charges. BPA, E-BPA-09, 7.

Cowlitz claims that the FPT rate is ideally suited for use in short distance situations because the formula to determine a specific customer's wheeling charge consists of only the FCRTS facility components pertinent to that customer's use, including a distance component. Cowlitz is a short distance customer of BPA and has compared the cost of lines for wheeling the Swift No. 2 project output. According to Cowlitz, construction of parallel facilities would cost approximately $1.65 million in 1984 dollars. Their figures show that under BPA's proposed IR-85 rate, the wheeling cost would be just over $390,000 per year after applying the short distance discount, whereas the annual wheeling cost under the FPT-85 rate would be $183,500, or 47 percent of the IR-85 rate. Therefore, Cowlitz argues, the short distance discount in the proposed IR-85 rate is not sufficient to remove the economic incentive for wheeling customers to construct short distance parallel lines. Smith, Cowlitz, E-CO-01R, 1-3. However, it is not Cowlitz's intent that the IR short distance discount be entirely eliminated. Smith, Cowlitz, TR 4510.

[page 359]

As stated in the proposed Transmission Policy, BPA's goal is for the region's transmission system to be planned and constructed to achieve as nearly as possible the maximum efficiency, reliability, economy, and other benefits as if the region's system were owned by a single utility. The short distance demand charge, available with the IR-83 rate schedule and continued in the IR-85 rate schedule for certain connection points that use specific FCRTS facilities for a distance of less than 75 miles, is intended to serve the "one-utility standard." BPA, E-BPA-09, 6. Statements in E-BPA-09, 22, and E-BPA-42, 11 regarding unavailability of the FPT rate for new agreements have been withdrawn. Chang, BPA, TR 4177, 4178.

**Decision**

*The FPT rate schedule is available for new wheeling agreements, including short distance wheeling, for customers selecting the FPT option for all of their firm wheeling needs on the FCRTS.*

**Issue #2**

*What are the appropriate criteria for granting the IR short distance discount?*

**Summary of Positions**

The granting of the IR short distance discount is a part of the contract negotiations process and will be subject to BPA's determination that the facilities used, including support facilities, are less than 75 circuit miles. Chang, BPA, TR 4218.

Puget argues that the sole criterion used to qualify a customer for the short distance discount, the use of FCRTS facilities for less than 75 circuit miles, should be acknowledged in the Record of Decision. Initial Brief, PSP&L, B-PS-01, 10. BPA should not imply, Puget further argues, that through the contract negotiation process conditions other than or in addition to the 75-mile requirement can be imposed on the availability of the short distance discount. Reply Brief, PSP&L, R-PS-01, 12.

**Evaluation of Positions and Decision**

The granting of their short distance discount is subject to BPA's determination, in the contract negotiation process, that the facilities being used, including support facilities, are less than 75 circuit miles. This determination can be complex where parallel systems are involved; therefore, a single universal criterion is not stated in the IR rate schedule.

[page 360]

## G. Network Wheeling Load Factors

**Issue #1**

*What is the appropriate IR load factor for the test year?*

**Summary of Positions**

In BPA's initial proposal, firm wheeling projections for determining the Network load factors were based on: (1) regional forecasts of the PNUCC; (2) contracts; (3) historical interchange records; and (4) BPA's forecast for Colstrip. BPA, E-BPA-09, Al.

The ICP contends that BPA's projections of energy wheeled over the Network under IR rates and Colstrip load factors are both too low. Wilson, PP&L, IC-09, 18, 19.

**Evaluation of Positions**

ICP argues that BPA underestimates the wheeling energy for the IR-85 rate in two respects. First, BPA's use of the Centralia units' load factor as a basis for computing load factors expected at Colstrip Units 3 and 4 is incorrect. Second, in BPA's rebuttal testimony (BPA, E-BPA-59R. Attachment 2, 3) the estimate of incidental wheeling on the Network has been improperly reduced and should not be used. The difference in incidental wheeling, 170 aMW, should be used to derive the energy rate for wheeling under the IR-85 rate schedule. Initial Brief, ICP, B-IC-01, 50.

ICP contends that Colstrip’s energy will either satisfy the participants' own loads or, as off-system sales, will displace more costly oil and gas fired generation. In either case, these units will run at high plant factors. Colstrip owners believe that Unit 3 can achieve at least a 65 percent capacity factor, and that 60 percent is appropriate for Unit 4, which will be classified as an immature unit for the first operating year, the test year. In recent years, the ICP has experienced wheeling load factors in the range of 40 percent. Wilson, PP&L, E-IC-09, 19, 20.

For the initial proposal, Colstrip Units 3 and 4 were forecast to operate at a combined load factor of 27 percent. This forecast was increased to 50 percent for the rebuttal testimony, more in league with the Centralia units, rather than the suggested 65 and 60 percent wheeling load factors. The overall 40 percent load factor projection is based on both historical use of wheeling contracts and expected conditions during the test period. Large thermal plants are projected to run at less than the plant availability for economic reasons because of the regional surplus. Chang, BPA, E-BPA-42, 7. Other than the unsupported assertion by the Colstrip owners that Units 3 and 4 will have availability factors of 65 and 60 percent, the parties have not demonstrated that BPA's own forecast of Colstrip Units 3 and 4 is an unreasonable one.

[page 361]

The energy component of the IR rate covers only that energy wheeled under a firm contract. The difference (170 aMW) between Appendices A and B of E-BPA-59R, which ICP asserts should be taken into account for deriving the IR-85 energy rate, reflects wheeling by utilities that do not have firm wheeling agreements and should not be included in the IR rate determination. However, wheeling by utilities which do not have firm wheeling agreements is used to determine excess revenues from ET. Therefore, all expected energy has been properly taken into account for purposes of deriving the energy rate under the IR-85 schedule. Silverstein, BPA, TR 4231, 4232.

ICP argues that the load factor applied to BPA’s firm transmission customers is much lower than annual load factors actually experienced. The primary source of the forecasts contained in Appendix A of E-BPA-09 is the Technical Appendix to the *Northwest Regional forecast of Power Loads and Resources* for July 1984-June 2004, PNUCC, March 1984. PNUCC data, ICP claims, are based on the use of "critical water," the worst water conditions of record, and thus do not reflect typical expected use of BPA’s transmission system by its wheeling customers. Wilson, PP&L, IC-09, 18, 19. ICP argues that BPA will always overcharge its wheeling customers if it bases its rates on worst conditions. Billing determinants, according to the ICP, should be increased to reflect expected water conditions and thermal plant load factors or, as an alternative, a load factor should be computed to reflect use by BPA's wheeling customers in recent years. Wilson, PP&L, E-IC-09, 20.

The wheeling load factor used to compute the IR energy rate in the initial proposal was 38 percent rather than the 32 percent associated with critical hydro operations. BPA, E-BPA-09, Table 13. The increase over critical hydro sales was based on forecasted nonfirm use of the Network as shown in Table 17 of the same exhibit. The overall load factor in the rebuttal testimony and the current forecast is now approximately 40 percent. Chang, BPA, E-BPA-59R, 3.

**Decision**

*The energy component of the IR-85 rate, as in the IR-83 rate, is appropriately based on the expected energy transmitted by BPA’s firm wheeling customers. In view of the expected regional surplus, BPA’s forecast of wheeling load factors for Colstrip Units 3 and 4 at less than plant* *availability is reasonable. The forecast shown in Appendix A of E-BPA-59R is reasonable and therefore the IR load factor for the test year is appropriate.*

## H. Intertie Adder

**Issue #1**

*Is an Intertie adder appropriate for recovery of transmission costs of extraregional sales?*
[page 362]

**Summary of Positions**

Wheeling customers are allocated and charged Intertie costs only if they use the Intertie in addition to the Network. BPA, E-BPA-09, 14. Wholesale power sales under SP and NF in the initial proposal were charged the same rate for transactions both in and out of the region. BPA, E-BPA-08, 65, 67.

LADWP recommends that BPA develop a single charge per kilowatt-hour for use of the Southern Intertie that would be applicable to all energy delivered over those lines. Initial Brief, LADWP, B-LA-01, 8.

ICP recommends that BPA wholesale power rates include Network costs, excluding Intertie costs, and that BPA include an Intertie service charge on extraregional transactions. Pre-Hearing Brief, ICP, P-IC-01, 22.

CEC recommends that BPA exclude the Fringe and Delivery segments from rates charged to the Southwest. Initial Brief, CEC, B-CC-01, 38.

**Evaluation of Positions**

ICP argues that BPA must separate or unbundle its power rates to indicate each rate component applicable to transmission on the various segments. BPA should also devise a better methodology for allocating costs to the transmission system. Initial Brief, ICP, B-IC-01, 4. To recover the full cost of nonfirm energy, the ICP contends, BPA should price nonfirm energy at the average system cost of generation and transmission and add the cost of intertie transmission for extraregional sales. Wilson, PP&L, E-IC-14, 2. According to ICP, there are several in consistencies in the way BPA derives and applies the Intertie service charge. First, BPA does not propose an Intertie service charge on its sales over the three Interties, except in the Emergency Capacity and Emergency Energy rates where the charge is quite small. Second, BPA includes a cost component for the interties in computing the SP, SE, and NF Standard energy rates. However, because the cost component is spread across the rates, regardless of whether the power is delivered at Network or Intertie points of delivery, Northwest purchasers will pay Intertie costs for transactions not involving the Intertie. As a result Pacific Northwest utilities selling displaced power outside the region will pay an inordinately high Intertie service charge. Pre-Hearing Brief, ICP, P-IC-01, 22. The ICP further argues that the SP rate should also contain a distinction between Pacific Northwest and Pacific Southwest Intertie cost allocations; that is, the SP-85 rate to the Southwest should equal the SP-85 rate to the Northwest, plus an adder for the Intertie. Kellerman, PGE, STR 1270-1272.

The ICP argues that BPA's calculation for the proposed NF rate includes only a small portion, one to two tenths of a mill, as an Intertie charge. This amount could be subtracted out before inclusion of the ICP proposed adder, thereby factoring an Intertie component into a fully allocated average system cost-based rate, such as firm power sold as nonfirm energy. Wilson, PP&L, STR 1203-1213. The ICP calculates that an appropriate cost-based extraregional rate for Standard nonfirm energy would include a proposed IS-85
[page 363] rate of 1.01 mills/kWh as an Intertie adder. Wilson, PP&L, E-IC-14, 3. The ICP continues that the adder approach is also consistent with regional preference requirements. Initial Brief, ICP, B-IC-01, 37.

LADWP notes that BPA's proposed transmission rate (IS-85) for wheeling has varied significantly throughout the rate adjustment proceeding and attributes the variation to the fluctuating percentage of total Southern Intertie cost allocated to the IS-85 rate class. Such variation could be eliminated, suggests LADWP, by simply developing a single rate that would be applied to all uses of the Intertie. Initial Brief, LADWP, B-LA-01, 8.

CEC contends that ICP took an inconsistent position in its proposal to disaggregate transmission costs which would raise prices to California. However, when disaggregation of transmission costs is adverse to ICP interests due to nonfirm rates to the Southwest being lower after exclusion of the delivery facilities identified, ICP found disaggregation inadvisable (TR 1205). CEC states that transmission delivery facilities are related to firm demand and would exist regardless of nonfirm energy delivered. Virtually no nonfirm energy is delivered to the Southwest by these segments, therefore rates to the Southwest should not contain these costs. CEC recommends that each nonfirm user should be required to pay, through the Standard rate, only for its own transmission delivery system. This would eliminate cross-subsidization for these transmission facilities. Given the Northwest's limited forecast of Standard rate use, leaving all of these Northwest transmission costs out of all nonfirm rates would also be reasonable and a less complicated approximation to adopt. Initial Brief, CEC, B-CC-01, 39-40.

LADWP's recommendation of a uniform charge for all sales over the Intertie has virtues in ease of understanding and administration. A uniform charge for Intertie use would make extraregional marketing more logical; it is simplistic and promotes consistency. However, a number of problems occur in the design of a uniform adder. First, some rates on the Intertie are capacity based (FPT and CF seasonal), some are energy based (NF and IS), and one has both capacity and energy charges (SP). Second, a uniform adder would not result from the COSA 12 CP cost allocation because of differing coincidences and load factors. Third, as CEC points out, if the cost of the Intertie is assigned only to Intertie users, it is not equitable to assign Fringe and Delivery segment costs to Intertie deliveries.

In consideration of these problems, a uniform Intertie charge was designed for Intertie uses. The first step allocates Intertie costs by the 12 CP method to CF, FPT, and the uniform adder class (IS, SP, and NF combined). The CF and FPT rate designs presented in the initial proposal are retained. Then, a suballocation of Intertie costs is made to the uniform adder class based on energy usage. No Fringe or Delivery costs are allocated to SP or NF. This results in a uniform

Intertie charge of 1.2 mills/kWh. ICP and PNGC support this rate for the IS-85 rate schedule. Reply Brief, ICP, R-IC-01, 25; Reply Brief, PNGC, R-PN-01, 1.

[page 364]

**Decision**

*To be consistent with the non-federal transmission rates where both a Network charge and an Intertie charge are applied to extraregional wheeling, an Intertie adder is adopted to recover transmission costs of NF and SP extraregional sales. The IS-85 rate of 1.2 mills/kWh is the Intertie adder applied to Intertie use for wholesale power sales. CEC's recommendation of excluding Fringe and Delivery transmission segment costs from the NF rate for both PNW and PSW sales is both practical and reasonable, and is adopted.*

### I. Wheeling Underrecovery

**Issue**

*Should the wheeling underrecovery be recognized?*

**Note**

This issue is addressed in Chapter III, Section E.

[page 365]

## X. IMPACT ANALYSIS

For the initial rate proposals BPA considered preparing an Environmental Assessment (EA) addressing the environmental impacts of the 1985 Wholesale Power and Transmission Rate proposals at that time, BPA anticipated a slight increase in its overall revenue requirement. For the final rate proposals, however, BPA's overall revenue requirement is less than the overall revenue that would be recovered by BPA's 1983 rates applied to the same loads. Since the overall revenue requirement has declined, BPA has determined that under National Environmental Policy Act (NEPA) procedures its rate change proposals are categorically excluded from the requirement that they be evaluated by either an EA or an Environmental Impact Statement (EIS). Therefore, BPA has not filed an EA or an EIS for the 1985 rate filing. Taves, BPA, E-BPA-45, 1.

Agencies are authorized by the Council on Environmental Quality (CEO) regulations to exclude categorically from environmental evaluation certain classes of actions. Neither an EA nor an EIS is required for agency actions that do not individually or cumulatively have a significant effect on the human environment. Council on Environmental Quality, *Regulations For Implementing the Procedural Provisions of The National Environmental Policy Act*, November 29, 1978, §1507.3, §1508.4.

The Department of Energy's (DOE) NEPA procedures (which are BPA's NEPA procedures as well), that implement the CEQ regulations, include this categorical exclusion:

> Rate increases for products or services marketed by DOE … which do not exceed the rate of inflation in the period since the last rate increase.

47 FR 7977, February 23, 1982, supplementing 45 FR 20694, March 28, 1980.

The change in BPA's revenue level from its rate proposals does not exceed the rate of inflation in the period since the last rate change. Taves, BPA, E-BPA-45, 1; Taves, BPA, TR 3139-3190. As a matter of policy, BPA considers factors other than overall revenue level that might reasonably affect the human environment in considering what environmental document is appropriate. Taves, BPA, TR 3181. BPA prepared and submitted a Draft Impact Analysis as a technical analysis of potential environmental implications that could reasonably be associated with the initial wholesale power and transmission rate proposals. BPA is submitting a Final Impact Analysis with its final wholesale power and transmission rate proposals. BPA's Impact Analysis provides decisionmakers and parties with an interdisciplinary study that integrates consideration of the natural and social sciences into the ratesetting process.

The Impact Analysis is not an environmental document required by NEPA or the implementing regulations of the Council on Environmental Quality, and thus [page 366] will not be filed with the Environmental Protection Agency. However, it is available to the Administrator and to the public as a disclosure of the potential environmental impacts of BPA's wholesale power and transmission rate proposals. BPA believes that the Impact Analysis reasonably analyzes potential environmental effects. Where appropriate, the Impact Analysis cross-references and thereby incorporates by reference the impact analyses in the 1983 Wholesale Power Rate EIS and the 1983 Transmission Rate EA.

During the rate hearing the ICUA, NIU, the WSFB, and the Northwest States Executive Irrigation Committee cited portions of the Draft Impact Analysis addressing potential implications to irrigated agriculture and that relied on study results by BPA (McKusick, BPA, E-BPA-44A; E-BPA-44A2; and E-BPA-44A3). Initial Brief, ICUA, B-IU-01, 5; Initial Brief, NIU, WSFB, and NSEIC, B-NI-WS-NE-01, 15. However, issues raised by these parties relate to conclusions by BPA and are dealt with elsewhere in the Record of Decision. *See* Chapter VIII, Section K.

**Issue #1**

*Is BPA's categorical exclusion appropriate even though BPA did not revise its Impact Analysis in response to the revised Nonfirm Energy rate proposals in rebuttal testimony?*

**Summary of Positions**

BPA states that the 1985 rate proposals are categorically excluded from the requirement that they be evaluated by either an EA or an EIS. Taves, E-BPA-45, 1.

LADWP asserts that BPA's categorical exclusion is inappropriate because BPA led the parties to believe that BPA intended to revise its analysis of environmental impacts if the Nonfirm Energy rates were revised. Reply Brief, LADWP, R-LA-01, 8.

## Evaluation of Positions

In testimony BPA stated that it would consider the nature of the revisions to the Nonfirm Energy rates and then decide whether or not the revisions required a change in the Impact Analysis. Taves, BPA, TR 3185. Therefore, LADWP is incorrect in its assertion that BPA led the parties to believe that BPA definitely intended to revise its analysis of the environmental impacts of the Nonfirm Energy rates.

BPA did review section 3.2.1.3 on Southwest Markets in the Impact Analysis and concluded that no revision to the document was needed. The original Impact Analysis covered the impacts reasonably attributable to the changes in the Nonfirm Energy rate. With respect to the Impact Analysis, no additional information was provided or incorrect information noted by any party during the course of the rate proceeding. If such information or comment had been [page 367] received, BPA would have made reasonable efforts to revise the analysis. No party suggested any impacts that BPA has not made a reasonable effort to analyze. Furthermore, there is no reason to believe that BPA would uncover any additional environmental impacts than those already addressed in the 1983 EIS, which is cross-referenced and thereby incorporated by reference into the Impact Analysis.

The Impact Analysis was submitted to the parties for their scrutiny and comment. There was more than adequate opportunity for parties to suggest revisions or provide data in support of changes to the document. BPA's analysis is based on data available to BPA and is reasonable. BPA cannot base its analyses on information which parties choose not to supply.

## Decision

*The fact that none of the parties supplied further information for the Impact Analysis or found errors in the content supports the reasonableness of the document and the Southwest Market section. The analysis of the impact of the revised Nonfirm Energy rate is reasonable in view of the information available; the categorical exclusion remains appropriate.*

## Issue #2

*Is BPA's categorical exclusion of the 1985 Wholesale Power and Transmission rates appropriate?*

## Summary of Positions

BPA determined that under NEPA procedures its 1985 rate proposals are categorically excluded from the requirement that they be evaluated by either an EA or an EIS. BPA sets rates to recover an overall revenue requirement. For the 1985 rates, this overall revenue requirement is lower than the overall projected revenue from the 1983 rates.

LADWP asserts that BPA's categorical exclusion is inappropriate because the rate increase to the Southwest will be in excess of 90 percent, which exceeds the rate of inflation since the last rate increase and, thereby, also exceeds the limit covered by the categorical exclusion. Reply Brief, LADWP, R-LA-01, 9. SCE also argues that BPA should develop a more comprehensive study of the environmental impacts associated with a nonregional nonfirm rate because the increase in the rate exceeds the general inflation rate. Opening Brief, SCE, B-CE-01, 52-53; Reply Brief, SCE, R-CE-01, 5.

**Evaluation of Positions and Decision**

The categorical exclusion covers "rate increases," which BPA holds to mean "overall rate increases." Council of Environmental Quality regulations direct that related actions with cumulative effects must not be segmented for analysis. 40 C.F.R. s 1508.25(a)(2). Under this approach, BPA does not dissect the rate increase and parcel the effect to each and every customer.
[page 368] The regulations do not require that the increase to each and every customer come under the limit of the rate of inflation. The categorical exclusion covers rate increases from a revenue perspective. From an overall revenue perspective, BPA's 1985 revenue requirement has decreased from the projected revenue that would have been received from the 1983 rates applied to the same loads. BPA has no reason to suspect that any significant environmental impacts are reasonably attributable to the 1985 rate proposals. Therefore, BPA's categorical exclusion is appropriate.

It is appropriate to reiterate that there is no evidence or information that has been presented by any party or participant that suggests that BPA's analysis is unreasonable. Parties that are aware of or have access to such information have had ample opportunity to present it, if it exists. BPA, in response, would have made reasonable efforts to analyze such information. BPA cannot analyze that which the parties choose not to present.

BPA is not the only supplier of nonfirm energy to the Pacific Southwest; other supply options exist. Should California purchasers choose not to purchase nonfirm energy from BPA, the effects would be no different than if the energy were unavailable in the first place (e.g., the result of poor water conditions). Purchase of nonfirm energy, in contrast to purchase of firm power, in many cases is optional on the part of the purchaser. The level of the average Nonfirm Energy rate is dependent upon market conditions, including competition from other power suppliers. As such, it is difficult to predict with certainty at what average rate nonfirm energy purchases will be made. Most of the changes in the 1985 Nonfirm Energy rate result from the decision of an Administrative Law Judge in a FERC 7(k) proceeding. However, the rate is still designed as an economic alternative to oil and gas fired generation in California. *See* Chapter VIII, Section A. Given this information, there is no reasonable basis for BPA to depart from the categorical exclusion granted other overall rate increases less than the rate of inflation merely to examine an optional nonfirm energy rate.

[page 369]

## XI. COMMENTS OF PARTICIPANTS

### A. Introduction

This chapter addresses the comments of the public concerning BPA's 1985 proposed wholesale power and transmission rate adjustments.

The participants ' portion of the official Record consists of the transcripts of 16 field hearings held October 8 through October 29, 1984, and January 15 through January 24, 1985, at which 153 persons made comments. BPA also received 614 letters and petitions by February 21, 1985, the close of the comment period. The names of the participants that commented on BPA's proposals are listed in Appendix C.

Based on review of this portion of the record, eight issues have been identified for evaluation. These issues reflect the general concerns expressed by the participants. Because of their volume, individual comments have been consolidated into a general representation of positions on each issue. The comments have not been attributed to particular individuals. Where more technical aspects of the issues have been addressed earlier in this Record of Decision, reference is made to the earlier discussion.

## B. Issues

### Issue #1

*Since the region has surplus power, why doesn't BPA follow the law of supply and demand and reduce its rates?*

### Evaluation of Positions and Decision

BPA has reduced its total costs for the period during which 1985 rates will be in effect. This has resulted in a reduction in BPA's revenue requirement and in some of its rates from current levels. BPA cannot further reduce its overall rates, however, simply because the region has surplus power. If BPA were to lower its rates and its costs remained unchanged, it would not be assured of selling enough extra power to cover the reduction in revenue due to lower rates. It therefore might not be able to cover its costs and pay its debts.

Given no changes in generation and transmission costs, consumers of power must be able to increase the amount of power they consume in response to a lower rate for BPA still to be able to cover its costs. This is difficult for most electric power consumers. For example, in order to use more power, an irrigator would have to irrigate more acres of land or apply more water to his [page 370] crops. Given today's low commodity prices, a farmer probably would not put more acreage under irrigation to lower his per unit cost of power when electricity is only one of the costs of production. The DSIs, in contrast, have shown that under certain circumstances they can increase consumption levels in response to a lower rate. This is due, in part, to the ability of the DSIs to shift production from plants outside of the region into the Pacific Northwest.

BPA is aggressively attempting to market power that is in excess of that needed to serve firm regional loads. Revenue BPA receives from selling surplus power pays some of BPA's costs and ultimately reduces regional firm power rates.

**Issue #2**

*Why does BPA not lower its rates to the PNW, instead of providing low rates to California?*

**Evaluation of Positions and Decision**

BPA sells energy to the Pacific Southwest (PSW) under two rate schedules, the Surplus Firm Power (SP) rate and the Nonfirm Energy (NF) rate. The SP rate is higher than the Priority Firm Power (PF) rate charged preference customers in the PNW for their firm power requirements.

Other sales to the PSW are made at the NF rates (which for simplicity are assumed in this discussion to be a single rate). Nonfirm energy is interruptible, available only during good water years, and cannot be counted on to serve firm loads. Nonfirm energy, pursuant to P.L. No. 88-552, is offered first to customers in the PNW. Because of its interruptible nature, however, not all nonfirm energy can be put to use by customers in the PNW. Most nonfirm energy is purchased by customers in the PSW because they can use it. BPA is increasing the NF standard rate to respond to Judge Miller's decision in the 7(k) Federal Energy Regulatory Commission proceeding on BPA's 1981 and 1982 NF rates. That decision indicates that the NF rate charged the PSW should recover most of the same types of costs that are recovered from the PF rate. In addition, all the benefits from nonfirm energy sales flow to BPA's firm power and transmission rates, including PF, because the revenues from nonfirm energy sales are credited to the costs that make up those rates.

BPA is attempting to increase the amount of nonfirm energy it sells in the PNW. For example, BPA has offered nonfirm energy to PNW irrigators in the spring months of 1983, 1984, and 1985 to help reduce the irrigators' production costs. However, for the most part, sales of nonfirm energy in the PNW bring lower prices than sales in the PSW. This is due to the fact that nonfirm energy purchases in the PSW are used for displacing high cost oil and gas fired generation.

In developing both NF and SP rates, BPA sought to recognize both the need to increase revenue and market constraints. If the rates are set too high and
[page 371] are in flexible, Pacific Southwest utilities will purchase from other utilities selling energy at lower rates, or will operate their own resources if it is less costly to do so than to purchase power from BPA. *See also* Chapter VIII, Section I.

**Issue #3**

*Should BPA have an automatic adjustment clause in its rates to permit rate adjustments that may be necessary in order to implement certain programs or directives?*

**Evaluation of Positions and Decision**

The Northwest Power Planning Council (Council) proposed that BPA rates should be designed with an automatic adjustment clause to permit rate adjustments in order to implement the Council's fish and wildlife program, to respond to Congressional directives, or to accommodate changing load and resource circumstances. The Council claims that the similar procedure currently employed for Supply System costs and exchange costs does not appear to pose insurmountable difficulties.

BPA currently has some flexibility to respond to changes in costs that may occur during the rate period. Budgeted funds need not all be spent. Small increases in expenditures in one area can be accommodated by reducing planned expenditures in other areas. Additional adjustment clauses to accommodate changes in expenditures or loads during a rate year would impose unnecessary additional administrative burdens on BPA. Furthermore, the possibility exists that BPA could implement adjustment clauses and grant refunds, while not in a position to make timely payments on its financial obligations. This would make little financial sense.

BPA already has taken steps to account for unanticipated changes in loads during the rate year through the use of 1939 water conditions (*see* Chapter 11, Section D) and the DSI incentive rate (*see* Chapter VIII, Section D). Unanticipated changes in costs are accommodated by the Supply System and Exchange Adjustment Clauses (*see* Chapter VIII, Section K) and, to a limited extent, by BPA's financial flexibility. Additional adjustment clauses would unnecessarily add to administrative burden for BPA and rate uncertainty for its customers.

**Issue #4**

*Should irrigators be offered a special rate?*

**Evaluation of Positions and Decision**

Historically, BPA played an active role in promoting irrigated agriculture. Now much of the agricultural community is experiencing financial
[page 372] difficulty. In periods of depressed farm prices, even small increases in power rates serve further to diminish the opportunity for farmers dependent on irrigation to stay in business.

BPA is including an irrigation discount in the Priority Firm Power rate to help relieve the current difficult financial condition of irrigated agriculture. In deciding to establish a discount. BPA took into consideration both the economic importance of irrigated agriculture to the region and the depressed financial condition of the agricultural sector.

**Issue #5**

*Should irrigators receive a lower seasonal rate based on cost of service?*

**Evaluation of Positions and Decision**

Some participants claim that BPA has not recognized the unique load characteristics of irrigated agriculture. They assert that, as an offpeak summer load, irrigation is the least expensive load for BPA to serve. They further contend that the cost of serving the irrigation load should be based on a separate cost of service analysis.

BPA does not serve irrigation load directly. BPA's Cost of Service Analysis and Marginal Cost Analysis examine the costs of serving BPA's wholesale power and transmission customers. If a retail utility serves an offpeak summer irrigation load, the cost of serving that load is factored into BPA's analyses. BPA's wholesale power rates thus implicitly reflect the offpeak summer season irrigation load.

BPA is implementing an irrigation discount in recognition of the financial hardships experienced by Pacific Northwest irrigated agriculture and the economic importance of irrigated agriculture to the region. It is important to note that BPA based its decision to grant the discount on the irrigators' current financial circumstances, not on cost of service considerations. *See* Chapter VIII, Section J.

**Issue #6**

*Should BPA decrease the direct service industrial (DSI) rate?*

**Evaluation of Positions and Decision**

Many participants stated that the current economic status of the PNW aluminum industry is critical. Weak markets coupled with a declining price for aluminum have placed the industry in jeopardy. Any rate increase or curtailment of existing incentive rate programs could cause the industry to leave the Pacific Northwest or even the nation; many jobs would be lost in the region.

[page 373]

The DSIs play a key role in the economy of the Pacific Northwest, provide BPA with a significant portion of its revenue, and provide important power reserves for the region. BPA recognizes the economic difficulty currently encountered by the PNW aluminum industry, which is the major DSI purchaser of BPA's electricity. To the extent permitted by law, BPA has considered the economic circumstances facing the aluminum industry in the design of the 1985 Industrial Firm Power (IP) rate structure. A customer charge was dropped from the IP-85 rate to help reduce the risk of plant closures and the resulting loss of revenue to BPA. The IP-85 rate includes an incentive rate provision to allow BPA to lower the rate to the DSIs during poor market conditions when such action would increase BPA revenue.

A significant change was made in the methodology for developing the industrial rate to conform with requirements of the Northwest Power Act concerning DSI rate development after July 1, 1985. The Act provides that after that date the rate should be comparable to rates charged public body and cooperative customers, plus a typical markup included by PNW publicly owned utilities in their rates to their industrial customers. Over the long term this will cause the DSI rate to track closely the rate charged to BPA's preference customers and, consequently, will provide greater assurance of rate stability to the DSIs. The Northwest Power Act also provides that BPA's industrial rate after July 1, 1985, not be less than the rate in effect for the contract year ending on June 30, 1985.

BPA recognizes that it may be necessary to take further steps to help ensure the continued viability of the DSIs. BPA is conducting a major study of various options for treating the DSIs in the long term. Some of the options under consideration include offering the DSIs a long term variable rate that would fluctuate with the price of aluminum, BPA funding of DSI electric power conservation or plant modernization, service of DSI loads by other power suppliers, and near term DSI rate reduction in return for increased ability to interrupt DSI loads in the future. BPA has attempted to involve the entire region in the examination of the DSI situation and possible solutions. A symposium and a series of public meetings have been held to explore the various options and issues and to receive public comment. *See* Chapter VIII, Section D.

**Issue #7**

*Has the IN-85 transmission rate been developed correctly?*

**Evaluation of Positions and Decision**

One participant, BC Hydro, claims that BPA's initially proposed IN-85 rate is too high because it was developed incorrectly. BC Hydro asserts that BPA derived its initially proposed IN-85 rate based on sales assumptions that were too low. They propose a credit for wheeling certain energy sales over the Northern Intertie. BC Hydro, letter, January 29, 1985. BC Hydro further claims that their sales to the PNW will increase based on their recent entry into the boiler displacement market. BC Hydro, letter, April 1, 1985.
[page 374]
This issue is discussed in Chapter IX, Section B.

**Issue #8**

*In view of the power surplus, should BPA's conservation program levels be reduced?*

**Evaluation of Positions and Decision**

Several parties to the 1985 BPA rate adjustment proceeding argue that BPA's funding level for conservation programs is too high. The points raised by parties and participants have been considered in the development of BPA's conservation program levels. BPA's analysis of the 1986 and 1987 program levels includes a review of actual program implementation experience. The program levels also include a downward adjustment as a result of decreased expectation of additional utility participation. BPA also applied cost-sharing assumptions to program development. BPA's conservation program levels included in the 1985 rate case were reduced through supplemental testimony nearly 10 percent and 11.5 percent for 1986 and 1987, respectively, to reflect the factors listed above and parties ' and participants ' arguments.

Although the region currently is experiencing a large power surplus, new resources will be needed in the future to meet expected increased demand for electricity. BPA has been charged by the Northwest Power Act to give first priority to conservation when acquiring new resources. BPA's conservation funding levels cause some rate impacts during the near term, yet are sufficient to allow BPA to develop the capability to acquire conservation when needed. *See* Chapter 11, Section C.

[page 375]
## XII. SUMMARY OF CONCLUSIONS

A. The proposed rate schedules have been designed to encourage the widest possible diversified use of electric energy, consistent with all statutory requirements, by providing rates for a wide range of services.

B. The proposed rate schedules encourage the equitable distribution of electric energy.

C. The Cost of Service Analysis fairly allocates the costs identified in BPA's Revenue Requirement Study. The proposed rates reflect the results of these studies, but also have been modified by the needs for conservation, efficiency, equity, ease of administration, continuity, and legal requirements identified in BPA's Wholesale Power Rate Design Study.

D. As demonstrated by the final Revenue Requirement Study, the proposed rates recover the costs associated with the production, acquisition, conservation, and transmission of electric energy and capacity, including amortization of the capital investment, interest on this investment, and all annual operating costs associated with the Federal projects and acquired power, including irrigation costs required to be paid out of power revenues and other costs and expenses incurred under appropriate provisions of law. The proposed rates provide revenues sufficient to repay, when due, the principal, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to the Federal Columbia River Transmission System Act and to establish and maintain reserve and other funds connected with these bonds. In compliance with a Federal Energy Regulatory Commission Order dated January 27, 1984, 26 FERC ¶61,096, BPA's revenue requirement is functionalized into its transmission and generation related components.

E. As demonstrated by the Revenue Requirement Study, BPA's wholesale power and transmission rates will allow BPA to repay all of its obligations. The proposed rates, as demonstrated by those studies, overall will provide the lowest possible rates to consumers, allowable by law, consistent with sound business principles.

F. The proposed rates, as demonstrated by the Revenue Requirement Study, will be sufficient to allow the Administrator to make payments to the credit of the reclamation funds required to be made by law, but will not provide for payment beyond the amounts required to be repaid from power revenues for these projects.

G. The proposed rates will provide sufficient revenue to repay the Federal investment for transmission and generation within the average service life of the facilities or 50 years, whichever is less.
[page 376]
H. The amortization of reclamation projects that BPA is required to repay from net revenues will not average more than $30,000,000 per year for any consecutive 20-year period, and these reclamation projects have not been scheduled in a manner that would result in exceeding that 20-year average figure.

I. The recovery of the cost of the transmission system, as demonstrated by the segmented analysis of transmission costs contained in the Cost of Service Analysis, is equitably allocated between Federal and non-Federal power utilizing BPA's transmission system. In addition, a separate accounting of the generation and transmission systems was provided in BPA's

Compliance Report, dated May 29, 1984. The present rate filing provides an update of the separate accounting provided in the Compliance Report using 1984 actual data.

J. The Hearing Officers have performed commendably their duties under section 7(i) of the Northwest Power Act to assure that a full and fair evidentiary hearing, open to all interested parties and participants, has been conducted on all issues relevant to BPA's wholesale power and transmission rates. All parties have been given every reasonable opportunity to engage in discovery, present testimony, engage in cross-examination of adverse witnesses, present oral argument, and submit briefs.

Based upon the foregoing, I hereby adopt as Bonneville Power Administration's final rate proposal the attached wholesale power and transmission rate schedules.

Issued at Portland, Oregon, this 26th day of April 1985.

Peter T. Johnson
Administrator

**APPENDIX A**
**List of Parties and Abbreviations**

| Parties | Abbreviations |
|---|---|
| ARCO Metals Company | ARCO |
| Association of Northwest Gas Utilities | NGU |
| Association of Public Agency Customers | APAC |
| Association of Washington Gas Utilities | WGU |
| Bonneville Power Administration | BPA |
| CP National Corp. | CPN |
| California Energy Commission | CEC |
| California PUC | CPUC |
| Central Lincoln PUD | Cen Lin |
| Chelan County PUD | Chelan |
| Clatskanie PUD | Clatskanie |
| Columbia River Inter-Tribal Fish Commission | CRITFC |
| Cowlitz PUD | Cowl |
| Cyprus Thompson Creek Mining Co. | CTC |
| Direct Service Industries | DSIs |
| Eugene Water & Electric Board | EWEB |
| Forelaws on Board | FOB |
| Grant PUD | Grt |
| Hanna Nickel | Hanna |
| Idaho Cooperative Utilities Association | ICUA |
| Idaho Power Company | IPC |
| Intalco Aluminum Corp. | Intalco |
| Intercompany Pool * | ICP |

| | |
|---|---|
| Los Angeles Department of Water & Power | LADWP |
| Montana Power Company | MPC |
| National Marine Fisheries Service | NMFS |
| Northwest Conservation Act Coalition | NCAC |
| Northwest States Irrigation Executive Comm. | NWIEC |
| Northwest Irrigation Utilities | NIU |
| Northwest Winter Peaking Utilities | NWPU |
| Northwest Utilities | NWU |
| Oregon Public Utilities Comm. | OPUC |
| Oregon State Farm Bureau Federation | OSFBF |
| Pacific Gas & Electric | PG&E |
| Pacific Northwest Generating Company | PNGC |
| Pacific Power & Light Company | PP&L |
| Portland General Electric Company | PGE |
| Public Generating Pool | PGP |
| Public Power Council | PPC |
| Puget Sound Power & Light | PSP&L |
| San Diego Gas & Electric | SDG&E |
| Seattle City Light | SCL |
| Southern California Edison | SCE |
| Tacoma City Light | TCL |
| U.S. Congressional Representative James Weaver | Congress |
| Utah Power & Light | UP&L |
| Washington State Farm Bureau | WSFB |
| Washington Utilities and Transportation Comm. | WUTC |
| Washington Water Power Company | WWPC |
| Western Montana Electric Generation and Transmission Coop, Inc. | WMEGT |
| Western Public Agencies Group | WPAG |

* The Intercompany Pool is not a Party

**APPENDIX B**
**LIST OF 1985 WHOLESALE AND TRANSMISSION RATE HEARINGS**
**PARTIES' WITNESSES AND REPRESENTATIVES**

| | |
|---|---|
| Akins, Hadley | Northwest States Irrigation Executive Committee |
| Albertson, Charles | National Marine Fisheries Service |
| Alcantar, Michael Peter | Direct Service Industries |
| Allcock, Charles E. | Intercompany Pool |
| Anderson, Wilbur | Western Montana Electric Generation and Transmission Cooperative, Inc. |
| Ashcom, Scott | Oregon State Farm Bureau Federation |
| Ater, Johnathan | Direct Service Industries |
| Ballbach, John | Puget Sound Power and Light |
| Balmer, Thomas | Cyprus Thompson Creek Mining Company |
| Barkeley, Donald | Idaho Power Company |

| | |
|---|---|
| Barker, William | City of Tacoma |
| Bar-Lev, Joshua | Pacific Gas and Electric Company |
| Baxendale, James | Portland General Electric Company |
| Baxendale, Richard | Public Power Council |
| Bearzi, Judith | Public Power Council |
| Beckemeier, Harold | Public Power Council |
| Beightol, Richard | Washington State Farm Bureau |
| Bennett, Barry | Oregon PUC |
| Bernheim, Joyce | Pacific Power and Light Company |
| Bodi, F. Lorraine | National Marine Fisheries Service |
| Brawley, Douglas R. | Public Power Council |
| Brown, Brian | National Marine Fisheries Service |
| Carter III, George C. | Direct Service Industries |
| Conkling, Roger L. | Association of Northwest Gas Utilities |
| Cook, Harold | Association of Public Agency Customers |
| Custer, Joe | Northwest Winter Peaking Utilities |
| Dahlke, Gary | Washington Water Power Company |
| Daly, Charles | San Diego Gas and Electric Company |
| Darby, Liston | Clatskanie People's Utility District |
| Dawsey, Charles E. | Northwest Irrigation Utilities |
| Dorsey, David | Chelan County PUD |
| Dotten, Michael | Direct Service Industries |
| Durocher, Hector J. | Direct Service Industries |
| Early, Michael | Direct Service Industries |
| Eiguren, Roy | Idaho Cooperative Utilities Association |
| Enderby, Marshall B. | California PUC |
| Evans, Dale | National Marine Fisheries Service |
| Fairchild, Peter | California PUC |
| Felgenhauer, Donald W. | Intercompany Pool |
| Fiddler, Richard | Public Generating Pool |
| Flanagan, Daniel | Montana Power Company |
| Fodrea, Jim | Grant County PUD |
| Foleen, Ray | Western Montana Electric Generation and Transmission Cooperative, Inc. and Northwest Winter Peaking Utilities |
| Frazee, Mark | Southern California Edison Company |
| Fulsom, Bruce | Washington Utilities and Transportation Commission |
| Furman, Donald | Portland General Electric Company |
| Garman, Gerry R. | Public Generating Pool |
| Garten, Allan | Association of Public Agency Customers |
| Gates, Bruce L. | Northwest Irrigation Utilities |
| Girard, Leonard | Pacific Power and Light Company |
| Goodell, Ralph | Cyprus Thompson Creek Mining Company |
| Gordon, Robert | Utah Power and Light Company |
| Gould, John | CP National Corporation |
| Graham, Paul | Oregon PUC |
| Greening, Jr., Robert | Pacific Northwest Generating Company |

| | |
|---|---|
| Grey, Robert | Hanna Nickel Smelting Company |
| Gustafson, James W. | Association of Northwest Gas Utilities |
| Guyer, Brent | Washington Water Power Company |
| Hager, Patrick L. | Portland General Electric Company |
| Hall III, Robert | Intalco Aluminum Company |
| Helgeson, Richard | Eugene Water and Electric Board |
| Heinrich, Charles | Portland General Electric Company |
| Herndon, Steven | Western Montana Electric Generation and Transmission Cooperative, Inc. and Northwest Winter Peaking Utilities |
| Hittle, David R. | Northwest Irrigation Utilities |
| Huffman, James | Chelan County PUD |
| Hull, Ronald J. | Southern California Edison Company |
| Hurless, Clayton | Idaho Cooperative Utilities Association |
| Hutchison, Coe M. | Western Public Agencies Group |
| Ichien, Arlene | California Energy Commission |
| Jacklin, Pamela | Pacific Power and Light Company |
| Johnson, Leayesh | Pacific Northwest Generating Company |
| Johnson, Ronald | Portland General Electric Company |
| Jones, Aaron C. | Northwest Irrigation Utilities |
| Kalcic, Brian | Association of Public Agency Customers |
| Kari, Donald | Puget Sound Power and Light Company |
| Kaufman, Paul | Public Power Council |
| Kellerman, Lawrence W. | Portland General Electric Company |
| Kemp, William J. | Pacific Gas and Electric Company |
| Kerr, Janice | California PUC |
| Kitchen, Gerald | Intalco Aluminum Company |
| Kline, Barton | Idaho Power Company |
| Knight, D.H. | Puget Sound Power and Light Company |
| Knitter, Keith | Public Generating Pool |
| Kunkel, Garry | Eugene Water and Electric Board |
| Lathrop, Robert | Columbia River Inter-tribal Fish Commission |
| Lauckhart, J. Richard | Puget Sound Power and Light Company |
| Lessner, Rochelle | Public Power Council |
| Little, Douglas | Idaho Power Company/Utah Power Company |
| Lubking, Eugene | Chelan County PUD |
| Lucas, Deborah | Public Power Council |
| Marcus, William B. | California Energy Commission |
| Martin, Michael D. | Cyprus Thompson Creek Mining Company |
| Mattson, Burton W. | California PUC |
| McCullough, Robert | Intercompany Pool |
| McGrane, John | Southern California Edison Company |
| McGuire, Duane | Public Generating Pool |
| McKenzie, A. Kirk | Direct Service Industries |
| McKinney, Robert | Cowlitz County PUD |
| McLennan, Robert | Pacific Gas and Electric Company |

| | |
|---|---|
| Merkel, Joel | Northwest Irrigation Utilities/Northwest States Irrigation Executive Cornmittee/Washington State Farm Bureau |
| Meyer, David | Washington Water Power Company |
| Miller, Max | Association of Public Agency Customers |
| Mizer, Bruce E. | Direct Service Industries |
| Moke, Elmer W. | Hanna Nickel Smelting Company |
| Morris, Frederic | Puget Sound Power and Light Company |
| Muller, David J. | Western Public Agencies Group |
| Mundorf, Terence | Western Public Agencies Group |
| Murphy, Paul | Direct Service Industries |
| Myers, E. Michael | Oregon PUC |
| Nelson, Robert | Pacific Power and Light Company |
| Norton, Floyd | Southern California Edison Company |
| Nuetzman, Ronald | Central Lincoln PUD |
| Nyegaard, Philip | Oregon PUC |
| O'Meara, Kevin | Public Power Council |
| Opatrny, Carol | Public Generating Pool |
| Otero, S. James | Los Angeles Department of Water and Power et al |
| Parmesano, Hethie | Los Angeles Department of Water and Power et al |
| Peseau, Dennis E. | Direct Service Industries |
| Poth, Jr., Harry A. | Intalco Aluminum Company |
| Redman, Eric | Direct Service Industries |
| Rockwood, Erven C. | Association of Northwest Gas Utilities |
| Rogers, Larry | Washington Utilities and Transportation Commission |
| Rolseth, Eric | Washington Utilities and Transportation Commission |
| Rostberg, Jeff | Idaho Cooperative Utilities Association |
| Sabin, Richard | Association of Northwest Gas Utilities |
| Saleba, Gary S. | Western Public Agencies Group |
| Saxton, Ronald | Direct Service Industries |
| Schneider, Robert K. | Western Public Agencies Group |
| Schoenbeck, Donald W. | Direct Service Industries |
| Shanker, Roy J. | Association of Public Agency Customers |
| Simpson, J. Calvin | California PUC |
| Sirvaitis, Robert V. | Intercompany Pool |
| Sloan, David | Pacific Power and Light Company |
| Smith, J. Leon | Cowlitz County PUD |
| Smith, John F. | Association of Northwest Gas Utilities |
| Spettel, Scott | Public Generating Pool |
| Stearns, Tim | Northwest Conservation Act Coalition |
| Stoltz, Jon T. | Association of Washington Gas Utilities |
| Taylor, Paulette | Intalco Aluminum Company |
| Tracy, Bud | Pacific Northwest Generating Company |
| Trankley, Lisa | California Energy Commission |
| Waddell, James A. | Southern California Edison Company |
| Waldron, Jay | Publlc Generating Pool/Eugene Water and Electric Board/Clatskanie PUD/Grant County PUD/Central Lincoln PUD |

| | |
|---|---|
| Walsh, James | San Diego Gas and Electric Company |
| Wapato, S. Timothy | Columbia River Inter-tribal Fish Commission |
| Weaver, Rep. James | Rep. James Weaver |
| Wedge, Herbert D. | Hanna Nickel Smelting Company |
| Weitzel, David L. | Intercompany Pool |
| White, Evan D. | Oregon PUC |
| Whitelaw, Ed | Idaho Cooperative Utilities Association |
| Whitney, Dennis B. | Los Angeles Department of Water and Power et al |
| Williams, Linda | Forelaws on Board |
| Williams, Walter | City of Seattle, City Light Department |
| Wilson, Robert C. | Intercompany Pool |
| Winter, Warren H. | Intercompany Pool |
| Winterfeld, Curt | Public Generating Pool |
| Wolverton, Lincoln | Public Power Council |