Department of Energy

Official File

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

CORPORATE

April 1, 2005

In reply refer to: KDP-7

Schwabe, Williamson & Wyatt, P.C.
Mr. Raymond S. Kindley
PacWest Center
Suites 1600-1900
1211 SW Fifth Ave
Portland, OR 97204-3795
(503) 222-9981

Re: FOIA Request No. 05-024

Dear Mr. Kindley;

On February 2, 2005, Bonneville Power Administration received a Freedom of Information Act (FOIA) from you, designated as our log number 05-024, in which you requested

> "Copies of all communication, correspondence, notes, e-mails, memoranda, meeting minutes, spreadsheets, analysis, reports, studies or other records (written or electronic) concerning any risk analysis or economic analysis of the BPA contracts with PacifiCorp and Puget Sound Energy numbered 01PB-10854 and 01PB-10885. These agreements are also know[n] as the financial settlement agreements and include the provisions for the $200 million in risk reduction discounts to these utilities.
>
> Please include in this request any information concerning BPA's comparison of actual or forecasted market power prices to the contract prices that BPA agreed to pay to PacifiCorp and PSE to buy down BPA's obligation to deliver power as contained in the financial settlement agreements. I would like to receive any analysis conducted before BPA entered into the agreements as well as any analysis conducted after the execution of the agreements."

BPA is hereby providing all records in its possession that are responsive to the above request, as displayed on the enclosed list.

Pursuant to 5 USC § 552(b)(5) (Exemption 5) of the FOIA, BPA is withholding a portion of the material on page 8 of the document entitled "Power Rates and New Power Contracts Briefing for Deputy Secretary", because of the attorney-client privilege. The withheld portion reveals confidential communications between a BPA attorney and its internal BPA client on issues in which the client sought legal advice. Release of this information would harm BPA's interests of ensuring that its legal counsel can provide frank and complete confidential advice to BPA staff. The redacted document and page are marked correspondingly. All other documents are provided in full, without redaction.

BPA has no other documents responsive to this request.

If you are dissatisfied with this determination, you may make an appeal within thirty (30) days of receipt of this letter to Director, Office of Hearings and Appeals, Department of Energy, 1000 Independence Avenue SW, Washington, D.C. 20585. Both the envelope and the letter must be clearly marked "Freedom of Information Act Appeal".

You have agreed to pay associated fees to process your request. In our letter of February 15, 2005, we estimated fees of $300 to complete your request. Search, reproduction, preparation, and review costs for this FOIA totaled $881.49. Because our estimate was for approximately $300.00, you will only be charged the estimated amount. You will be sent an invoice for $300.00 under separate cover by our accounting department.

If you have any questions regarding this response, you may contact me at 503-230-5110.

Sincerely,

Debra Smiley

Debra Smiley
Freedom of Information Act Office

Enclosures
List of Materials Responsive to BPA FOIA #05-024
Responsive Materials

List of Materials Responsive to BPA FOIA #05-024

Partial Stipulation and Settlement Agreement, WP-02-E-BPA-70(E1), discusses use of market prices in rate case, 38 pages, February 15, 2001.

Testimony of Allen L. Burns, Sydney D. Berwager, and Michael J. DeWolf WP-02-E-BPA-70, testimony on market prices, 15 pages, undated.

Risk Analysis Study and No-Slice Analysis, testimony of Sidney L. Conger et al, WP-02-E-BPA-71, 12 pages, undated.

Filling the Remaining Augmentation & Rate Mitigation Deficit/BPA's Peaking Resource Strategy, 5 pages, circa March 21, 2001.

Financial Settlement Agreement and Amendment to Residential Exchange Program Settlement Agreement with PacifiCorp, Record of Decision, 44 pages, May 23, 2001.

Amended Residential Exchange Program Settlement Agreement with Puget Sound Energy, Administrator's Record of Decision, 45 pages, June 6, 2001.

Power Rates and New Power Contracts Briefing for Deputy Secretary, [PowerPoint package], 16 pages, June 14, 2001.

Washington DC Briefings, [PowerPoint package], 12 pages, June 18-19, 2001.

Proposed Contracts or Amendments to Existing Contracts with the Regional Investor Owned Utilities Regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY2007-2011, Administrator's Record of Decision, 31 pages, May 25, 2004.

2002 Supplemental Power Rate Proposal Administrator's Record of Decision WP-02-A-09, 12 page excerpt, June 20, 2001.

Deputy Secretary Briefing on IOU Rate Reduction Purchases, 3 pages, undated circa June 25, 2001.

Forward Prices for FY02-06 Forward Blocks of Mid C Flat Energy, 2 pages, undated circa June 2001.

LB CRAC % - Low Market Case, 9 pages, undated circa May 2001.

UNITED STATES DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2002 Bonneville Power Administration	**)**	
Proposed Wholesale Power Rate	**)**	**BPA Docket No. WP-02**
Adjustment Proceeding	**)**	

PARTIAL STIPULATION and SETTLEMENT AGREEMENT

This Partial Stipulation and Settlement Agreement ("Partial Settlement") effective this 15th day of February 2001, is entered into by the undersigned Parties in the above-referenced rate case (hereinafter referred to individually as a "Party" or collectively as "the Parties").

A. BACKGROUND

1. The Bonneville Power Administration ("BPA") issued a Record of Decision in BPA Docket No. WP-02, dated May 15, 2000, and as amended by errata dated June 22, 2000, adopting power rates for the five-year rate period commencing October 1, 2001, through September 30, 2006 ("May Proposal"). BPA subsequently filed the proposed power rates with the Federal Energy Regulatory Commission ("FERC") requesting approval of the rates effective October 1, 2001.

2. On August 4, 2000, BPA filed a motion with FERC requesting a stay in FERC's review of BPA's WP-02 Wholesale Power Rate filing.

3. On December 12, 2000, BPA reopened the WP-02 proceeding to amend the May Proposal. BPA published its Amended 2002 Bonneville Power Administration Power Rate Case Proposal, Docket No. WP-02 ("Amended Proposal") to address BPA's changing financial obligations due to increased loads and market price volatility.

4. In January and February 2001 a series of noticed meetings were held where a group of customers outlined a proposal to modify the Amended Proposal. Over the weeks the Parties and BPA staff worked out the specifics of this proposal. The Parties eventually reached agreement on the structure for resolving the issues raised in Amended Proposal and have translated that into this Partial Settlement.

5. This Partial Settlement resolves issues raised in the May Proposal and Amended Proposal, as set forth herein.

B. AGREEMENT

1. Parties' Proposal

The Parties have jointly developed a proposal to address certain of the issues presented in the Amended Proposal. The elements of the proposal are described in Exhibit "A" hereto ("Parties' Proposal").

2. Required Actions

a. BPA Staff agrees to file a Supplemental Proposal as required by the Revised Procedural Schedule in the Amended Proposal proceeding that incorporates all the elements of the Parties' Proposal as set forth in Exhibit A. Parties acknowledge that BPA's Supplemental Proposal will not exactly mirror the language contained in the Parties' Proposal and that such divergence, so long as it does not undermine the intent of the Parties' Proposal, does not constitute a breach of this Partial Settlement.

b. Except as provided in section B(2)(g), if BPA's Supplemental Proposal incorporates all the elements of the Parties' Proposal, all Parties other than BPA Staff agree to file testimony in both their direct and rebuttal cases that is consistent with, and in support of, the Supplemental Proposal. The Parties shall be free to file direct and rebuttal testimony in response to issues raised in testimony by any party to the WP-02 proceeding , so long as such testimony is not inconsistent with the Parties' Proposal.

c. Except as provided in section B(2)(g), the Parties agree that if the Supplemental Proposal filed by BPA Staff differs from the Parties' Proposal in any material way, the Parties shall, in good faith and using their best efforts, attempt to develop a revised proposal that is as similar as practicable to the Parties' Proposal prior to the deadline for filing Parties' direct testimony in this proceeding. If the Parties reach agreement, the Parties other than BPA will submit testimony consistent with the agreed upon changes. All Parties agree to file testimony in their direct and rebuttal cases that is consistent with, and in support of, the Supplemental Proposal as revised.

d. Except as provided in section B(2)(g), in the event that the Parties are unable to develop a revised proposal after a good faith attempt to develop such a proposal within the time permitted pursuant to section B(2)(c), then each Party is free to file direct and rebuttal testimony addressing any aspect of the Supplemental Proposal, and may file rebuttal testimony to any party's direct case. In such event, this Partial Settlement shall have no further force or effect, and shall terminate without liability to any party. The Parties agree that this Partial Settlement shall not be cited by any Party for any purpose in any administrative or judicial forum; provided however, that any Party may cite this Partial Settlement for the purpose of explaining why a Party did not raise an issue earlier in the WP-02 rate proceeding in compliance with this Partial Settlement. In such event, the Parties shall have no obligation to file testimony in this proceeding in support of the Supplemental Proposal, and no issue raised by a Party at its earliest opportunity (whether in direct, rebuttal or a Party's brief) will be deemed to be waived.

e. In addition, subsequent to filing the Supplemental Proposal, BPA Staff will perform additional Slice/Non-Slice Cost Shift analyses, incorporating a variety of load loss assumptions, to determine the impacts of using revenue and load bases for allocating Augmentation True Up costs. The results of this analysis will be made available to all Parties and will be discussed at a noticed meeting to be held no later than seven days after BPA files its Supplemental Proposal, along with proposals to reduce the level of the overall rate increase. At such meeting, the Parties shall attempt to reach agreement on the appropriate basis for making such allocation, and any other revisions to which the Parties mutually agree.

f. In the event that the Parties reach agreement on the appropriate basis for the allocation of Augmentation True Up costs, such resolution will be incorporated in the Parties' Proposal and the Parties (other than BPA Staff) will include such resolution in their direct testimony, and BPA Staff will support such resolution in its rebuttal testimony.

g. In the event that any Party objects to the resolution of the appropriate basis for the allocation of Augmentation True Up costs, regardless of what that resolution may be, such Party may by written notice to all other Parties to be served not less than seven days prior to the date for the Parties, other than BPA, to file their direct case, elect to include such issue on Exhibit B and reserve such issue for litigation, and by doing so shall be free to take whatever position such Party deems appropriate in its direct and rebuttal testimony with regard to such issue notwithstanding any provision of this Partial Settlement. The Parties further agree that despite any objections a Party may have regarding the resolution of such issue, that all other aspects of this Partial Settlement remain valid and enforceable.

h. So long as section B(2)(d) of this Partial Settlement is not invoked, the Parties agree that the provisions of the Parties' Proposal that address the Safety Net CRAC (SN CRAC) and the attendant section 7(i) procedures to implement such an SN CRAC are consistent with, and permitted by, the language in each Party's respective Subscription power sales agreement with BPA. Each Party waives all arguments to the contrary and agrees not to challenge (or support or join any challenge) to its Subscription power sales agreement on the basis that the implementation procedures or the SN CRAC violates its Subscription power sales agreement in any administrative or judicial forum whatsoever.

i. So long as section B(2)(d) of this Partial Settlement is not invoked, each Party waives all arguments that the financial benefits payable for FY 2002-2006 under each Subscription Residential Exchange Settlement Agreement with BPA should not be calculated using a forward flat block price forecast of $38/MWh as proposed by BPA in its Supplemental Proposal. BPA agrees that in any subsequent WP rate proceeding, or any other proceeding, it will not cite the WP-02 rate proceeding as evidence of the propriety of (or precedent for) using a forward flat block forecast for calculation of financial benefits under the Subscription Residential Exchange Settlement Agreements different from the forward flat block forecast used to determine BPA's augmentation costs.

j. So long as section B(2)(d) of this Partial Settlement is not invoked, the Parties agree that execution of this Partial Settlement waives the right of any Party hereto to seek review, including before the FERC or the 9th Circuit Court of Appeals, of any issue raised by a Party in the May Proposal and decided finally by BPA therein, except those issues reserved by a Party by listing such issues in Exhibit B. Except as provided in section B(2)(d), the Parties agree not to assert in any forum that they did not waive, as part of this Partial Settlement, the right to seek FERC or judicial review of any issue raised by a Party in the May Proposal that is not reserved in Exhibit B. The Parties acknowledge that listing an issue in Exhibit B does not, in itself, revive such an issue for appeal if such issue was not preserved in the WP-02 proceeding by the Party listing the issue.

k. Prior to the date direct testimony must be filed, the Parties agree to file with the Hearing Officer in this proceeding a motion requesting an order stating that issues raised by Parties in their Initial Brief or Brief on Exceptions and decided in the May Proposal and set forth on Exhibit "B" need not be re-argued in their brief in this proceeding to preserve such issue for appeal to the FERC or the Court of Appeals for the 9th Circuit.

l. This Partial Settlement is intended to be consistent with the Subscription Contracts, however, to the extent there are any inconsistencies between a Subscription contract and this Partial Settlement, the Parties agree to use good faith efforts to negotiate revisions to such contracts to remove such inconsistencies with this Partial Settlement.

3. Regulatory Commission Actions

a. The Idaho Public Utilities Commission, Montana Public Service Commission, Public Utility Commission of Oregon, and Washington Utilities and Transportation Commission (collectively "the Commissions") are all signatories of this Stipulation and Partial Settlement.

b. The Commissions agree to provide collectively at least one witness to file testimony in support of the Parties' Proposal and Partial Settlement.

C. GENERAL PROVISIONS

1. The Parties enter into this Partial Settlement to avoid further expense, inconvenience, uncertainty and delay in this reopened WP-02 proceeding. By executing this Partial Settlement, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed in arriving at the terms of this Partial Settlement or the Parties' Proposal, nor shall any Party be deemed to have agreed that any provision of this Partial Settlement or Parties' Proposal is appropriate for resolving issues in any other proceeding regardless of whether the Parties' Proposal or Partial Settlement is adopted by the Administrator, except as expressly provided in this Partial Settlement.

2. If the Administrator issues a Final Record of Decision in the WP-02 docket that is consistent with the Parties' Proposal, the Parties agree to support this Partial Settlement and the Parties' Proposal in the WP-02 docket proceeding and before the FERC.

3. Each Party represents that it has the power to execute this Partial Settlement and any other documentation relating hereto, and that it has taken all necessary action to obtain any authorization needed to execute and perform under this Partial Settlement.

4. Notwithstanding any other provision of the Partial Settlement: (1) any Party may respond, in a manner not inconsistent with this Partial Settlement, to any issue raised at the FERC or in judicial review of WP-02 or otherwise; and (2) in the event that the Ninth Circuit Court of Appeals invalidates any rate adopted in WP-02 and remands such rate to BPA, no Party shall be limited by this Partial Settlement from raising any issues within the scope of the remand, or be deemed to have waived any issue, by virtue of this Partial Settlement.

5. Nothing in this Partial Settlement is intended to preclude any of the Commissions from exercising any right they may have to intervene in proceedings reviewing the WP-02 rate case (whether at FERC or the Ninth Circuit Court of Appeals) and BPA will not oppose such interventions.

This Partial Settlement may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation and Partial Settlement Agreement is effective on the ____ day of __________________, 2001, regardless of the date signed by each executing Party below.

Bonneville Power Administration

Byron G. Keep

By:

Avista Corporation

By:

Puget Sound Energy, Inc.

By:

Portland General Electric Company

By:

PacifiCorp

By:

Idaho Power Company

By:

Montana Power Company

By:

Washington Utilities and
Transportation Commission

By:

Idaho Public Utilities Commission

Public Utility Commission
Of Oregon

This Stipulation and Partial Settlement Agreement is effective on the ____ day of ________________, 2001, regardless of the date signed by each executing Party below.

Bonneville Power Administration

By:

Avista Corporation

Scott Morris

By: February 15, 2001

Puget Sound Energy, Inc.

By:

Portland General Electric Company

By:

PacifiCorp

By:

Idaho Power Company

By:

Montana Power Company

By:

Washington Utilities and Transportation Commission

By:

Bonneville Power Administration

By:

Avista Corporation

By:

Puget Sound Energy, Inc.

By: William A. Gaines
Vice President, Energy Supply

Portland General Electric Company

By:

PacifiCorp

By:

Idaho Power Company

By:

Montana Power Company

By:

Washington Utilities and
Transportation Commission

By:

Idaho Public Utilities Commission

Public Utility Commission
Of Oregon

Bonneville Power Administration

By:

Avista Corporation

By:

Puget Sound Energy, Inc.

By:

Portland General Electric Company

Mary E. Turner

By:

PacifiCorp

By:

Idaho Power Company

By:

Montana Power Company

By:

Washington Utilities and
Transportation Commission

By:

Idaho Public Utilities Commission

By:

Public Utility Commission
Of Oregon

By:

Bonneville Power Administration	**Avista Corporation**
By:	By:
Puget Sound Energy, Inc.	**Portland General Electric Company**
By:	By:
PacifiCorp	**Idaho Power Company**
M R Stight By: Vice President, Regulation	By:
Montana Power Company	**Washington Utilities and Transportation Commission**
By:	By:
Idaho Public Utilities Commission	**Public Utility Commission Of Oregon**

_______________, 2001, regardless of the date signed by each executing Party below.

Bonneville Power Administration	Avista Corporation
By:	By:
Puget Sound Energy, Inc.	Portland General Electric Company
By:	By:
PacifiCorp	Idaho Power Company
By:	By: Richard Riazzi Sr. Vice President Marketing & Generation
Montana Power Company	Washington Utilities and Transportation Commission
By:	By:
Idaho Public Utilities Commission	Public Utility Commission Of Oregon

IN THE MATTER OF:

UNITED STATES DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2002 Bonneville Power Administration	)	
Proposed Wholesale Power Rate	)	**BPA Docket No. WP-02**
Adjustment Proceeding	)	

PARTIAL STIPULATION and SETTLEMENT AGREEMENT

The Washington Utilities and Transportation Commission approves the Partial Stipulation and Settlement Agreement.

DONE AND DATED at Olympia, Washington this 16th day of February, 2001.

Washington Utilities and Transportation Commission

Marilyn Showalter, Chairwoman

Richard Hemstad, Commissioner

THE IDAHO PUBLIC UTILITIES COMMISSION as co-signatories to the Partial Stipulation and Settlement Agreement in 2002 Bonneville Power Administration Proposed Wholesale Power Rate Adjustment Proceeding - BPA Docket No. WP-02.

Dated this 15th day of February, 2001.

DENNIS S. HANSEN, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

PAUL KJELLANDER, COMMISSIONER

Oregon

John A. Kitzhaber, M.D., Governor

Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2557
(503) 373-7394

DATED at Salem, Oregon, and effective this 13 day of February, 2000.

OREGON PUBLIC UTILITY COMMISSION

Ron Eachus
Chairman

Roger Hamilton
Commissioner

Joan Smith
Commissioner

RE: BPA-related Stipulation

Post-it® Fax Note 7671	Date 2-15-01 # of pages 1
To KYLE SCIUCHETTI	From
Co./Dept. Public Power C.	Co. OR PUC
Phone #	Phone #

Montana Public Service Commission

Gary Feland, Chairman
Jay Stovall, Vice-Chairman
Bob Anderson
Matt Brainard
Bob Rowe

1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601
Telephone: (406) 444-6199
FAX#: (406) 444-7618
http://www.psc.state.mt.us

RE: Approval of Bonneville Power Administration Partial Stipulation & Settlement

DONE AND DATED at Helena, Montana, and this 14th day of February, 2001.

MONTANA PUBLIC SERVICE COMMISSION

Gary Feland

GARY FELAND, Chairman

Jay Stovall

JAY STOVALL, Vice Chairman

Bob Anderson

BOB ANDERSON, Commissioner

Matt Brainard

MATT BRAINARD, Commissioner

Bob Rowe

BOB ROWE, Commissioner

By:

By:

Montana Public Service Commission

Northwest Requirements Utilities

By:

By:

Pacific Northwest Generating Cooperative

Public Power Council

By:

By:

Public Generating Pool

Western Public Agencies Group

By:

By:

Market Access Coalition

Seattle City Light

By:

By:

By:

By:

Montana Public Service Commission

Northwest Requirements Utilities

By:

By:

Pacific Northwest Generating Cooperative

Public Power Council

By: R. Erick Johnson pc for PNGC

By:

Public Generating Pool

Western Public Agencies Group

By:

By:

Market Access Coalition

Seattle City Light

By:

By:

By:	By:
Montana Public Service Commission	Northwest Requirements Utilities
By:	By:
Pacific Northwest Generating Cooperative	Public Power Council
By:	By: (not including Cauly Utility Board)
Public Generating Pool	Western Public Agencies Group
By:	By:
Market Access Coalition	Seattle City Light
By:	By:

PPC

Public Power Council

1500 NE Irving, Suite 200
Portland, Oregon 97232
(503) 232-2427
FAX (503) 239-5959

February 15, 2001

Mr. Peter Burger
Office of General Counsel LP-7
Bonneville Power Administration
905 NE 11th Avenue - 7th Floor
Portland, Oregon 97232

RE: Partial Stipulation and Settlement Agreement in the WP-02 Rate Proceeding

Dear Mr. Burger:

The Public Power Council (PPC) has signed the Partial Stipulation and Settlement Agreement (Agreement) entered into among several parties to the WP-02 rate case on February 15, 2001.

Attached is a letter from Dan Seligman representing the Canby Utility Board. Canby is a member utility of PPC. Canby does not agree to the terms of the Agreement and therefore will not sign the document. The purpose of my letter is to declare that PPC's execution of the Agreement no way limits Canby's right to pursue any issue it deems appropriate in the WP-02 rate proceeding or any other forum. In other words, Canby is not bound by PPC's position in this matter.

Thank you for your attention to this matter. If you have any questions, please call me at (503) 232-2427.

Sincerely,

C. Clark Leone
Manager

Attachment
cc: WP-02 Service List

COLUMBIA RESEARCH CORPORATION

209 W. Evergreen Blvd., Suite 605 • Vancouver, Washington 98660 • Phone (360) 695-7422 • Fax (360) 695-7426

February 15, 2001

Ms. Jerry Leone, Manager
Public Power Council
1500 N.E. Irving, Suite 200
Portland, Oregon 97232

SUBJECT: Partial Stipulation and Settlement Agreement
BPA Rate Case WP-02

Dear Jerry:

My client, the Canby Utility Board, does not join in the Partial Stipulation and Settlement Agreement for the Bonneville Power Administration's WP-02 rate case.

If the PPC signs the Stipulation, please note Canby's position so that it is clear to BPA that my client does not waive the right to raise certain issues later in this proceeding.

Thank you for your assistance. Please call if you have any questions about this request.

Sincerely,

Dan Seligman

Dan Seligman
Attorney at Law

By:	By:
Montana Public Service Commission	Northwest Requirements Utilities
By:	By:
Pacific Northwest Generating Company	Public Power Council
By:	By:
Public Generating Pool	Western Public Agencies Group
By: Jay T. Waldron	By:
Market Access Coalition	Seattle City Light

By:

By:

Montana Public Service Commission

By:

Northwest Requirements Utilities

By:

Pacific Northwest Generating Company

By:

Public Power Council

By:

Public Generating Pool

By:

Western Public Agencies Group

Terence L Mundorf

By: Terence L. Mundorf, Attorney

Market Access Coalition

By:

Seattle City Light

By:

By:

By:

Montana Public Service Commission

Northwest Requirements Utilities

By:

By:

Pacific Northwest Generating Cooperative

Public Power Council

By:

By:

Public Generating Pool

Western Public Agencies Group

By:

By:

Market Access Coalition

Seattle City Light

By: John A. Cameron
Traci A. Grundon
Davis Wright Tremaine, LLP
Attorneys for Market Access Coalition

By:

By:

By:

Montana Public Service Commission

Northwest Requirements Utilities

By:

By:

Pacific Northwest Generating Cooperative

Public Power Council

By:

By:

Public Generating Pool

Western Public Agencies Group

By:

By:

Market Access Coalition

Seattle City Light

By:

By: Kevin J. Clark

EXHIBIT A

PARTIES' PROPOSAL

The proposal has the following elements

A. LB CRAC

1. LB CRAC will be calculated using an augmentation market price based on the forecast market price for the rate period and will be applied to the following rate schedules: PF rates, excluding Slice, Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC), Cost-Based Index Rate, actual power deliveries under the Residential Load (RL-02), and New Resource Firm Power (NR-02). The CRAC does not apply to Pre-Subscription contracts or Slice product or the financial portion of the Residential Exchange Settlement.

2. The forecast of market prices for the rate period to be used in setting the final rates will be performed as late in the rate process as practicable while permitting its inclusion in the draft Record of Decision. BPA will conduct one or more public workshops with the parties on this forecast. BPA will make available to the parties prior to the workshop the inputs used and the results of the forecast, and will make available at the workshop(s) for questioning the BPA staff that participated in the preparation of the forecast.

3. BPA shall give due consideration to the comments and suggestions made by the parties regarding the forecast during the course of the workshop(s) in preparation of the forecast that is finally included in the draft Record of Decision.

B. Augmentation True Up

BPA and the other Parties have discussed two bases for allocating the costs of Augmentation True Ups, those being revenues and loads. The lack of time has made it impracticable for the Parties to analyze the impacts of both approaches or to explore potential alternative approaches. The Parties intend to do such analysis after the filing of Supplemental Proposal, and will attempt to reach consensus on either of these methods or some alternative approach to use in this proceeding.

<u>Establishing the October 2001-March 2002 Load-Based Cost Recovery Adjustment Clause (LB CRAC)</u>

1. By June 1, 2001, BPA will estimate Forecasted Total Load it expects to serve during each month of Fiscal Year (FY) 2002 under subscription contracts and other existing contracts. BPA will estimate amount of sales subject to the LB CRAC, identifying separately Slice sales. Forecasted Total Load shall exclude Slice load and shall reflect any known reductions (for contract terminations, amendments, load losses, or buydowns) and reasonably predictable load reductions for BPA's full and partial service contracts.

2. BPA shall also forecast the total Expected Revenue for the first half of that year at its Base Rates (excluding any CRACs) from sales subject to the LB CRAC, including separately indentifying Expected Revenue from Slice sales (assuming 1,732 aMW in the Net Cost of the Inventory Solution). BPA shall calculate the Average Base Rate by dividing this Expected Revenue by the forecasted number of megawatt-hours of sales subject to the LB CRAC. BPA shall calculate the amount of Net Augmentation Costs In Base Rates already included in Expected Revenue by dividing forecasted number of megawatt-hours of sales subject to the LB CRAC by the number of megawatt-hours of sales assumed for each six months in the May Proposal and multiplying the resulting ratio by the six-month amount of net augmentation costs already included in the base rates from the May Proposal.

3. BPA will assume federal system output (reduced for system obligations and transmission losses) of 7,070 aMW minus Slice sales, with a monthly shape proportionate to the percentage each month's Forecasted Total Load is of the annual Forecasted Total Load. BPA will calculate its Expected Augmentation Quantity by subtracting this assumed federal system capability from the Forecasted Total Load for each such month.

4. BPA will calculate its Assumed Average Net Augmentation Price by computing for each month of the period the weighted average price per megawatt-hour it has paid for power to be delivered in that month. If BPA has not purchased for any month in the period as much power as its Expected Augmentation Quantity, it shall calculate the residual amount needed. For these residual amounts, BPA shall obtain Forward Price Strips during the last five business days of May and average those strips in with the average price BPA paid for its advance purchases for that month to establish the Assumed Average Augmentation Price for the first half of the contract year. BPA will subtract from this Assumed Average Augmentation Price the Average Base Rate to establish the Assumed Average Net Augmentation Price for the period.

5. BPA shall multiply the Assumed Average Net Augmentation Price times the Expected Augmentation Quantity, add the payments made by BPA to any customer to buy-down loads (including Conservation Augmentation), add the cost of options to hedge the cost of augmentation, and subtract the Net Augmentation Costs In Base Rates to calculate the Expected Net Additional Augmentation Cost for the period. The Expected Net Additional Augmentation Cost shall be multiplied by the ratio of the Slice portion of Expected Revenues to forecasted Expected Revenues from all sales subject to the LB CRAC to establish the Slice Share of the Expected Net Additional Augmentation Cost which shall be added to the Slicers' share of the Slice Revenue Requirement. The Non-Slice Share of Expected Net Additional Augmentation Cost shall be divided by the Expected Revenue from non-Slice sales subject to the LB CRAC to establish the LB CRAC to be paid during the period by all non-Slice sales subject to the LB CRAC. This results in a single percentage to be

Revenue Requirement for that period, that difference shall be added to the Slice Share of Expected Net Additional Augmentation Costs for the upcoming period, and if it is less it shall be subtracted.

10. To calculate the Revised Non-Slice Share of Net Additional Augmentation Costs, BPA shall calculate a Revised Average Net Augmentation Price for those months by: (1) updating the Assumed Average Net Augmentation Price to include the weighted average price of any additional power BPA purchased before each of those months (but after calculating the Assumed Average Net Augmentation Price the preceding June or December); and (2) if BPA had still not purchased all of the Revised Augmentation Quantity, valuing the residual amounts by replacing the Forward Price Strips used to calculate the Assumed Average Net Augmentation Price for that six-month period, with Forward Price Strips for power to be delivered each individual month obtained (averaged) during the last five business days prior to that individual month.

11. BPA shall calculate the Non-Slice Share of the Revised Net Additional Augmentation Cost for those months by multiplying the Revised Augmentation Quantity times the ratio of Expected Revenue from non-Slice sales subject to the LB CRAC divided by the Expected Revenue from all sales subject to the LB CRAC times the Revised Average Net Augmentation Price, and adding the non-Slice share of any additional payments not assumed in the Non-Slice Share of Expected Net Cost of Augmentation Cost made by BPA (1) to any customer to buy-down loads (including Conservation Augmentation), or (2) for additional options to hedge the cost of augmentation. If the Non-Slice Share of the Revised Net Additional Augmentation Cost is greater than the Non-Slice Share of the Expected Net Additional Augmentation Cost, the difference shall be added to the Non-Slice Share of the Expected Net Additional Augmentation Cost for the upcoming period; and if it is less, the difference shall be subtracted.

12. The determination of the Augmentation True Up will be subject to audit by BPA's independent outside auditing firm, and the results of such audits will be available to customers. One year after the end of each of the six month periods described in this section B, the Parties, other than BPA, will be allowed to review or audit the documentation of any augmentation power purchase made by BPA that is used either in the calculation of the Assumed Augmentation Net Cost, Revised Slice Share of Net Additional Augmentation Costs or the Non-Slice Share of the Revised Net Additional Augmentation Costs. Prior to that time, the Parties, other than BPA will not have access to the terms of the purchases in order to verify the above referenced calculations. BPA will retain verifiable records necessary to facilitate such audits.

C. FB CRAC

1. FB CRAC will use the trigger amounts and the maximum collection amounts of the CRAC set out in the BPA May Proposal for FYs 2003, 2004, 2005 and 2006. For FY

applied to all non-Slice adjustable rates and charges (demand, energy, and load variance).

6. As early as possible in June (and every six months thereafter for subsequent periods), BPA shall hold a publicly noticed workshop to review its preliminary calculations with customers subject to the LB CRAC and any other interested parties. BPA will make available to the parties prior to the workshop the inputs used and the results of the forecast, and will make available at the workshop(s) for questioning the BPA staff that participated in the preparation of the forecast. After considering any comments it receives and revising its calculations as it deems appropriate, BPA shall notify customers before June 30, 2001 of the LB CRAC and the Slice Share of the Expected Net Additional Augmentation Costs that it will apply for the first six-month period (and by the end of each December and June of the rate period for subsequent periods).

Establishing the LB CRAC for Subsequent Periods

7. By December 1, 2001 (and every six months thereafter), BPA shall perform the same calculations as above to establish the LB CRAC and the Slice Share of the Expected Net Additional Augmentation Costs for the next six-month period, (using Forward Price Strips averaged during the last five business days of each November and May as appropriate for the upcoming six month augmentation period), but with the Slice and Non-Slice Shares of Expected Net Additional Augmentation Cost for the upcoming period increased or decreased as follows.

8. BPA shall calculate a Revised Augmentation Quantity for the most recently completed six months (only October and November 2001 in the case of the December 2001 calculation) by replacing the Forecasted Total Load used in the calculation pursuant to Section B.3 above for those months with Actual Total Load under subscription contracts and other existing contracts.

9. BPA shall calculate the Revised Slice Share of Net Additional Augmentation Costs by: (1) replacing the Expected Augmentation Quantity with Revised Augmentation Quantity; (2) updating the Assumed Average Net Augmentation Price to include the weighted average price of any additional power BPA purchased at least 120 days before each of those months (but after calculating the Assumed Average Net Augmentation Price the preceding June or December) (3) if BPA had still not purchased all of the Revised Augmentation Quantity, continuing to value the residual amounts with the Forward Price Strips used the preceding June or December to calculate the Assumed Average Net Augmentation Price for that six-month period; (4) adding the Slice Share of any additional payments not assumed in the Slice Share of Expected Net Cost of Augmentation Cost made by BPA to any customer to buy-down loads (including Conservation Augmentation), or for additional options to hedge the cost of augmentation purchases. If the Revised Slice Share of Net Additional Augmentation Costs is more than the Slice Share of Expected Net Additional Augmentation Costs that was added to the Slicers' Share of the Slice

2002, the threshold from the BPA May Proposal will be used, the amount to be collected shall not be subject to a dollar cap but may not exceed the amount needed for reserves to equal the FB CRAC threshold.

2. FB CRAC may be triggered at the start of any FY during the rate period based on the Third Quarter Review forecast of end-of-year accumulated net revenues in the prior year. Collection will begin in October and continue for 12 months. There will be a true-up of the amount collected in March on the FY using BPA's audited actual year-end financial results for the preceding FY.

3. FB CRAC will be applied to the following rate schedules: PF rates, excluding Slice, Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC), Cost-Based Index Rate, actual power deliveries under the Residential Load (RL-02), and New Resource Firm Power (NR-02).. The FB CRAC will not apply to the Pre-Subscription contracts or Slice product or the financial portion of the Residential Exchange Settlement.

D. SN CRAC

1. A Safety-Net CRAC will be available if the Administrator determines that after implementation of the FB CRAC and any Augmentation True Ups, either of the following conditions exist:

   - BPA forecasts a 50 percent or greater probability that it will nonetheless miss its next payment to Treasury or other creditor, or
   - BPA has missed a payment to the Treasury or some other creditor,

2. The SN CRAC will be an upward adjustment to posted power rates to which it applies. The SN CRAC will modify the FB CRAC parameters. BPA will propose changes to the FB CRAC parameters that will, to the extent market and other risk factors allow, achieve a high probability that the remainder of Treasury payments during the FY 2002-2006 rate period will be made in full. BPA's proposal could include changes to the Revenue Amount, the duration (the length of time the SN CRAC would be in place, which could be more than 1 year), and the timing of collection. BPA will calculate the Revenue Amount that the changes in the FB CRAC parameters are intended to generate during the period that such changes are effective. Such Revenue Amount shall be collected by means that will result in a uniform percentage increase to all rates subject to the FB CRAC and a commensurate decrease in the financial portion of the Residential Exchange Settlement

3. The SN CRAC applies to power purchases under these firm power rate schedules: PF Preference (Exchange Program, and Exchange Subscription), Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), New Resource Firm Power (NR-02) and both the actual power deliveries and the financial portion of the

Residential Exchange Settlement. The CRAC does not apply to Pre-Subscription contracts or Slice product.

SN CRAC Notification Process

4. At the time the Administrator determines that the SN CRAC has triggered, BPA will send written notification of the determination to customers that purchase power under rates subject to the SN CRAC and to other interested parties. Such notification shall include the documentation used by BPA to determine that the SN CRAC has triggered, the amount of any forecast shortfall, and the time and location of a workshop on the SN CRAC.

5. The purpose of the SN CRAC workshop will be to discuss with customers and interested parties the cause of shortfall, and any proposed changes to the FB CRAC that will achieve a high probability that the remainder of Treasury payments during the FY 2002-2006 rate period will be made timely. In determining which proposal to include in its initial proposal in the SN CRAC Section 7(I) proceeding, BPA will give priority to prudent cost management and other options that enhance Treasury Payment Probability (TPP) while minimizing changes to the FB CRAC.

SN CRAC Hearing Process

6. As soon as practicable after a determination that the SN CRAC has triggered, BPA will publish a Federal Register notice initiating an expedited hearing process to be conducted in accordance with Section 7(I) of the Northwest Power Act. The hearing shall be completed within 40 days, unless a different duration is agreed to by the parties. Upon completion of such hearing, BPA will submit the following documentation in support of a request for review and confirmation: Separate Accounting Analysis, current and revised revenue tests, the proposed revisions to the FB CRAC parameters and the administrative record compiled by BPA in the SN CRAC proceeding.

E. Exchange Settlement

1. Financial benefits for the IOUs will be calculated for Settlement purposes using a price of $38/MWh.

2. Power deliveries to the IOUs under the Settlement will be subject to all three CRACs (LB, FB and SN).

3. Financial benefits to the IOUs under the Settlement will only be subject to SN CRAC.

4. Both power deliveries and the 900 aMW of federal power delivered as financial benefits will be used to calculate the IOU participation in DDC disbursements.

F. Slice Rate

1. The Slice rate will be subject to the augmentation price true up in the manner described in Section B.

2. The Slice rate will not be subject to the LB, FB or SN CRACs.

3. Slice loads will not participate in any distribution under the DDC.

G. Dividend Distribution Clause

1. The DDC is a clause establishing criteria that will determine when dividends should be distributed and the amount that should be distributed. The DDC enables BPA to distribute dividends to customers.

2. The DDC applies to power customers under these firm power rate schedules: PF rates, excluding Slice, , Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02) including the financial portion of any Residential Exchange Settlement , New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS) that are subject to the LB, FB and SN CRACs. The DDC does not apply to Pre-Subscription contracts or Slice product.

Formula for the Calculation of the Dividend Distribution Amount

3. The DDC process will be implemented if audited actual accumulated net revenues for the end of any of the fiscal years 2002-2005 are above the DDC Threshold value.

4. Actual Accumulated Net Revenues (AANR) are generation function net revenues, as accumulated since 1999, at the end of each of the Fiscal Years 2002 through 2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices, with the following exceptions. For purposes of determining if the DDC Threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the May 2000 WP-02 Final Studies. The impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the CRAC threshold has been reached. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the DDC; accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be audited by BPA's

independent outside auditing firm in 2002 and will be confirmed by the auditing firm in each subsequent year.

5. DDC Threshold is the minimum level of AANR that must be realized before a dividend distribution is considered. The DDC Threshold is $250 million for the end of Fiscal Years 2002, 2003, 2004, and 2005. **[change to whatever level is equivalent to $1.7, $1.5, $1.2, and $1.2 billion dollars in the appropriate FYs in BPA financial reserves.]**

6. DDC Amount is the aggregate amount that is available to be distributed to customers. The DDC Amount may be equal to zero and will be determined by the following formula:

   AANR – DDC Threshold

7. The threshold for any fiscal year will be adjusted upward by the following:

   a. In the event there has been a power system emergency during the fiscal year, and there are agreed-upon fish and wildlife mitigation efforts related to the emergency operations for which BPA has not yet spent, said amounts will be added to the threshold amount for that year.

   b. BPA fish and wildlife direct program costs previously budgeted for expenditure in that fiscal year for implementation of the Biological Opinion that were not spent in that fiscal year due to suspension or deferral, and for which a need continues, will be added to the threshold amount for that year.

8. The Power Customer DDC Amount will be converted to a percentage (the Power Customer DDC Percentage), which will be applied to all power customer rates subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers.

9. The Power Customer DDC Percentage will be determined by the following formula:

   Power Customer DDC Percentage equals:
   Power Customer DDC Amount
   Divided by the
   DDC Revenue Basis

   Where DDC Revenue Basis is the total generation revenue for the loads subject to the DDC for the fiscal year in which the DDC implementation begins, based on the then most current revenue forecast.

10. Each covered power customer will receive a rebate equal to the Power Customer DDC Percentage applied to their total charge for energy, demand and load variance. For customers receiving financial benefits under the Residential Exchange

Settlement, their total charge will include the product of each such customer's AMW share of 900 aMW (based on its portion of the total financial benefits) and the sum of the Residential Load (RL-02) rate and the amount of any CRAC applied to power deliveries under such rate.

Determination and Timing of a Dividend Distribution

11. In January of each year of the rate period (FY 2002-2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. The Administrator will distribute dividends in every FY in which the AANR exceeds the DDC Threshold.

12. Dividends distributed to customers are included in bills for deliveries beginning May 1, and, for any Fiscal Years 2003-2005, remain in effect for 12 months i.e., through April 30 of the following year. In the last year of the rate period (FY 2006), the rebate would expire on September 30, 2006.

Determining How the Distribution is Allocated

13. The first $15 million of the DDC Amount, if the DDC Amount exceeds $15 million, or the entire DDC Amount if it equals $15 million or less, will be allocated to qualifying customers' participating in the C&R Discount. The C&R Discount is a rate mechanism designed to encourage incremental conservation and renewable resource development by BPA's power purchasers under PF, IP, RL, and NR rate schedules. See C&R Discount GRSPs, Section II.A. The DDC amounts will be allocated based on the total revenues paid to BPA since the beginning of the rate period or the last DDC distribution, whichever is later. Such revenues shall include the product of 900 aMW and the applicable RL Rate for the financial portion of the Residential Exchange Settlement

Dividend Distribution Notification Process

14. <u>Financial Performance Status Reports</u>

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the fiscal year ending September 30. By December 1 of each year, BPA shall post on its website the unaudited AANR.

15. <u>Notice of DDC Trigger</u>

On or about January 15 in each of the Fiscal Years 2003-2006, BPA will notify all power customers and rate case parties if the AANR exceeds the DDC Threshold. (If the December unaudited AANR report for the generation function indicated that the DDC Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified). Notification will include the AANR for the prior fiscal year, the DDC Amount, the calculation of the DDC Amount, and the estimated resulting Power Customer DDC Percentage for each applicable rate schedule. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request.

16. On or about April 15 of any of the Fiscal Years 2003-2006 in which the AANR exceeds the DDC Threshold, BPA shall notify customers of the final calculation of the DDC Amount and, if applicable, the resulting level of the Power Customer DDC Percentage to be applied to each applicable firm power rate schedule.

17. The DDC will at the end of each FY automatically return to customers BPA reserves as follows: FY 2003, reserves in excess of $1.7 billion; FY 2004, reserves in excess of $1.5 billion; FYs 2005 and FY 2006, reserves in excess of $1.2 billion. This sum will be converted to an accumulated net revenue equivalent. In determining the amount of reserves available for return to the customers, costs previously budgeted for expenditure in the prior FY for implementation of the Biological Opinion that were not spent in the FY for which they were budgeted, due to suspension or deferral, will be deducted from reserves to determine if the threshold for returning reserves to customers has be met.

18. The determination of the AANR will be audited in 2002 and confirmed in each year thereafter by BPA's independent outside auditing firm, and the results of such audit or confirmation will be made available to customers eligible for DDC distributions.

H. DSI RATE

The DSI rate will be subject to the LB, FB and SN CRACs, and to the augmentation true up in the same manner as the PF, RL and NR rates.

EXHIBIT B

I. Public Power Council

The sections of Public Power Council's (PPC's) Initial Brief (WP-02-B-PP-01) dated February 28, 2000, that PPC preserves and does not waive for purposes of Exhibit B of the Partial Stipulation and Settlement Agreement are as follows:

1. Section II.2.B: BPA Should Eliminate TAC, TACUL and SUMY and Revise its Design for the Unauthorized Increase Charge and the Excess Factoring Charge.

2. Section II.4.A: The "Compromise Approach" Does Not Exempt DSI Rates from Implementation of the Legal Floor Rate.

3. Section II.4.B: BPA Rates Must Be Based Upon Substantial Evidence, Including Implementation of a Properly Calculated Industrial Margin.

4. Section II.4.C: BPA's Offer of a DSI Variable Rate Must Not Increase Risk to Other BPA Customers.

5. Section II.5.A. BPA Has Administratively Conferred Rights to Certain Utilities and Denied Them to Others, In Violation of Existing Statutory Provisions.

6. Section II.5.B: The Proposed Subscription Settlement Is Generous and May Exceed the Value of the Traditional Exchange.

7. Section II.5.C: BPA's ASC Methodology is Neither As Temporary Nor As Malleable As the IOUs Claim.

8. Section II.5.D: There is No Inherent Bias in the 7(b)(2) Rate Test Model.

9. Section II.5.E: BPA Improperly Mingled the Rate Design Step and the Subscription Step.

10. Section II.5.F: Inclusion of Uncontrollable Costs in 7(g) Adjustment to the 7(b)(2) Rate Test is Not Supported.

11. Section II.5.G: Inclusion of Power From the Pricing of the Mid-Columbia Dams in 7(b)(2) Resource Stack is Appropriate.

12. Section II.5.H: Conservation and Other Resources Should Be Least-Cost Ordered in 7(b)(2) Resources Stack.

E. **BPA's Aggressive Briefing Schedule Denied the Parties an Adequate Amount of Time to Fully Brief the Issues in the Draft ROD**

V. The Public Utility Commission of Oregon

The Public Utility Commission preserves the issues raised in its Brief on Exceptions to the extent not inconsistent with the Partial Settlement.

VI. Pacific Northwest Generating Cooperative

Pacific Northwest Generating Cooperative, on behalf of itself and its Members (collectively, PNGC), reserves (*i.e.*, does *not* waive) the following issues, and all arguments related thereto, for future litigation in WP-02 proceedings before the BPA Administrator, at the FERC and in the Ninth Circuit Court of Appeals:

1. The Targeted Adjustment Charge for Uncommitted Loads, including without limitation that the TACUL is unlawful and should be eliminated. *See*, PNGC's Initial Brief, Section II; PNGC's Brief on Exceptions, WP-02-R-PN-01, Sections 1-7; Administrator's Final ROD, WP-02-A-02, Section 19; FERC Docket No. EF00-2013.

2. The right to reply to any settling party's challenge to the Administrator's determinations concerning General Transfer Agreements. *See*, Initial Brief of PNGC, Section III; Administrator's Final ROD, WP-02-A-02, Sections 8.3 and 9 (June 22, 2000)

3. Demand and Load Variance Charges, including without limitation that these charges were not set low enough by the Administrator. *See*, Initial Brief of PNGC, Section V; Administrator's Final ROD, WP-02-A-02, Sections 10.3, 10.4 and 10.5 (June 22, 2000).

4. The Administrator's calculation of the Low Density Discount for Slice Product customers. *See*, PNGC's Brief on Exceptions, WP-02-R-PN-01, Section 7; Administrator's Final ROD, WP-02-A-02, Section 10.12 (June 22, 2000).

5. The right to reply to any settling party's challenge to the Administrator's determinations concerning the Low Density Discount. *See*, Initial Brief of PNGC, Section IV; Administrator's Final ROD, WP-02-A-02, Section 10.12 (June 22, 2000).

6. The right to reply to any settling party's challenge to the Administrator's determinations concerning Delivery Segment costs being retained in power rates on a rolled-in basis. *See*, Initial Brief of PNGC, Section VI; Administrator's Final ROD, WP-02-A-02, Section 8-15 (June 22, 2000).

7. To the extent not specified above, PNGC also reserves the right to assert any argument not expressly precluded by the Partial Settlement in response to any argument made by any settling or non-settling party that is not precluded by the Partial Settlement.

WP-02 BPA Data Response

Request No.: PG-BPA: 134

Request: Witnesses:
Exhibit: WP-02-E-BPA-77, Attachment A, pages 14-15

Please state and explain the rationale for the proposal to use revenues to effectively allocate net augmentation costs between Slice and non-Slice rates, rather than (a) the approach used to reflect other BPA costs in the calculation of the Slice Rate, which was determined in BPA's Record of Decision published in May 2000, or (b) the approach to this issue proposed by BPA in the December 2000 Amended Proposal."

Response: First, regarding the specific requests contained in this data request, neither the ROD in May 2000 nor the December 2000 Amended Proposal contained a methodology to adjust both Slice and non-Slice power rates multiple times each year during the rate period for changes in BPA's augmentation costs. In fact, the issue now is not a Slice vs. non-Slice issue. Rather, it is an issue of which power products subject to LB CRAC recover what amount of the additional net augmentation costs.

The approaches to recovering net augmentation costs in May ROD and December 2000 Amended Proposal are different than that proposed in the Supplemental Proposal. It simply is not possible to explain some distinction that is alleged to be introduced in this Supplemental Proposal when neither the May 2000 or December 2000 proposals contained no method for calculating and then apportioning these costs in one way between individual power products. No such segmentation was required in either of those two prior proposals.

In the May ROD, there was only one CRAC, which allocated the amount of revenues to be raised by non-Slicer power products based on revenues (WP-02-FS-BPA-02A, p. 283). However, that one CRAC did not attempt to collect BPA's net augmentation costs as the currently proposed LB CRAC attempted to do.

In the December Amended Proposal, BPA proposed two very different methods for collecting net augmentation costs from customers. Slice share of augmentation costs was determined based on share of the FBS. Non-Slice power products' share of net augmentation costs was determined using loads. Together, these two approaches collected more than 100% of BPA's net augmentation costs.

So, the Supplemental Proposal contains a new methodology to recover net augmentation costs using twice-annual rate adjustments to all power products subject to LB CRAC. This new approach required a new methodology, and, as a result, this new methodology cannot be directly compared to methodologies in the earlier proposals.

Second, turning to the broader question of the justification for using revenues, there are several reasons why BPA considers this to be the correct approach.

The first policy objective driving the Amended Proposal and Supplemental Proposal is that "It should be as simple as possible." (WP-02-E-BPA-70, pg. 6, line 4). One principle underlying settlement discussions was that the LB CRAC method ought to assure that each power product subject to the LB CRAC is charged with recovering the same percentage increase in revenue.

The approach to determining the equal percentage increases in revenue required from each power product subject to LB CRAC is to use revenues in the determination of the LB CRAC%. In this calculation, net augmentation cost are spread across the sum of all expected revenues from all power products subject to LB CRAC for the entire 6-month duration of the LB CRAC. The resulting percentage, referred to as LB CRAC%, is then applied equally to each power product subject to the LB CRAC. This approach assures that each separate power product, subject to the LB CRAC, will then have a revised rate that is determined using the same percentage increase in required revenue.

Additionally, the problem BPA is grappling with is one of sufficient revenues. Net augmentation costs are expressed in dollars. Revenues from power products without the LB CRAC is expressed in dollars. By spreading the former dollars over the latter dollars, and applying the resulting percentage to revenues without the LB CRAC, results in incremental dollars required from each separate power product that is subject to the LB CRAC. This appears to BPA to be a very fair and equitable approach to recover net augmentation costs.

April 10, 2001

cc: Hearing Clerk and Service List (via electronic mail)

Errata to
Final 2002 Power Rate Proposal
Statements A-F

WP-02-FS-BPA-08(E1)

Page B-2:	Insert Table B-1 (will be out of order—after Table B-2).
Page C-4:	Replace Statement C, pages C4-C134, with Statement C pages C4 - C99 errata.
Page C-135:	Replace Table C-1, pages C135-C142, with Table C-1 pages C100-C107 errata.
Page D-2:	Replace Statement D, pages D2-D315, with Statement D pages D2- D407 errata.

TESTIMONY OF

ALLEN L. BURNS, SYDNEY D. BERWAGER, AND MICHAEL J. DEWOLF

Witnesses for Bonneville Power Administration

SUBJECT: POLICY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Allen L. Burns. My qualifications are contained in WP-02-Q-BPA-08.

A. My name is Sydney D. Berwager. My qualifications are contained in WP-02-Q-BPA-03.

A. My name is Michael J. DeWolf. My qualifications are contained in WP-02-Q-BPA-16.

Q. Have you previously filed testimony in the WP-02 proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to generally describe changes occurring since our Amended Proposal to the 2002 Power Rate Case (Amended Proposal), in particular, substantially higher and more uncertain market prices and a decline in the expected value of starting reserves for Fiscal Year (FY) 2002. We then summarize some fundamental design changes to our Amended Proposal for Load-Based (LB), Financial-Based (FB), and Safety-Net (SN) Cost Recovery Adjustment Clause (CRAC) mechanisms and to the Dividend Distribution Clause (DDC). These changes are a result of settlement discussions with rate case parties. Although these discussion did not yield a settlement with all parties, the discussions did resolve most issues with all the investor-owned utilities (IOUs) and state commissions (PUCs) as well as virtually all of the rate case parties that represent nearly all of the region's individual public utilities. The design changes to the CRACs and DDC and other solutions that are part of the Partial Settlement Agreement (*see* Attachment A) are different enough from Bonneville Power

Administration's (BPA) Amended Proposal to warrant this Supplemental Power Rate Proposal (Supplemental Proposal). This testimony provides an overview of the Supplemental Proposal and supporting policy decisions made to support this proposal.

Q. How is your testimony organized?

A. This testimony is organized in four sections. The first section is this introduction. Section 2 describes the need for this Supplemental Proposal. Section 3 explains the policy objectives of the Supplemental Proposal. Finally, Section 4 summarizes the major changes in this Supplemental Proposal.

Section 2. Need for the Supplemental Proposal

Q. Please describe why BPA has decided to file this Supplemental Proposal.

A. There are three reasons why BPA is filing this Supplemental Proposal. First, BPA's forecast for starting rate period reserves has dropped very substantially since the forecast in our Amended Proposal. Second, market prices available now for power during the first two years of the rate period are significantly higher than BPA had forecast in the Amended Proposal. Regardless, BPA would have prepared an update to the Amended Proposal to show the impact of these revised forecasts on BPA's proposed rates. The third reason is that, as a result of discussions with the rate case parties, BPA reached a Partial Settlement Agreement with many of those parties. Part of that agreement is that BPA will file a Supplemental Proposal reflecting the Partial Settlement Agreement.

Q. Please describe the changes that have occurred in BPA's financial situation since BPA filed its Amended Proposal in December.

A. Since December, forecasts for run-off for this water year have declined substantially. Water Year forecasts in our 2002 Final Power Rate Proposal (May Proposal) and Amended Proposal assumed average water for both this FY 2001 and for the next five years of the rate period – 102.4 million acre feet (MAF). By contrast, this year could be the fourth lowest runoff year on record, with current runoff forecasts now at 67 MAF.

These conditions are requiring BPA to purchase much more power this year than expected to meet loads, at extremely high prices, and have reduced the amount of surplus energy BPA can sell this year. As we described in our Amended Proposal, prices in the wholesale electricity market have been extremely volatile and high. BPA has seen these increased market prices during this year. In fact, during one week in January alone, BPA purchased over $50 million in power to meet load. This is putting tremendous pressure on our end-of-year reserves. End-of-year reserves translate into starting rate period reserves. In our May Proposal, starting reserves were estimated to be $842 million on an expected value basis. In our Amended Proposal, our starting reserves expected value estimate had increased to $929 million. Now, the expected value of BPA's starting reserves estimate has dropped to $309 million. There is still a significant range of uncertainty surrounding this estimation of starting reserves. This is driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices. BPA will update the starting reserve level in the final studies based upon the results of the second quarter review. It should be noted that the new estimates of starting reserves from the First Quarter Review of FY 2001 may differ somewhat from the estimates used in this Supplemental Proposal due in large part to the difference in timing for the two studies.

Q. How does this drop in starting reserves affect BPA's rates and cost-recovery adjustment charges?

A. Starting reserves are a key risk mitigation tool in this rate proposal. (*See* Lefler, *et al.*, WP-02-E-BPA-73.) A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools need to be made.

Q. Besides the increase in market prices for power in the past few months, are there other changes to market prices that BPA has noticed?

A. Yes. Market prices during the rate period are higher in the first years of the rate period, ranging from $200/megawatthour (MWh) to $240/MWh for FY 2002, and then drop during the last years of the rate period, to a range between $40/MWh and $60/MWh in FY 2006. This compares with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around $48/MWh, where expected prices for individual years did not vary by more than $5/MWh from the $48/MWh average.

Q. Please explain how this affects BPA.

A. Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market. Therefore, BPA has revised the LB CRAC so that our expected revenues closely match the shape of our augmentation costs.

Q. BPA has participated in settlement talks with the rate case parties. What has been the result of these discussions?

A. BPA staff held productive discussions with rate case parties to explain the changes to starting reserves and market price escalation and uncertainty that have occurred since the Amended Proposal and that must be addressed in this rate case. BPA and a large group of the parties were able to reach agreement on how BPA should address these problems. The Partial Settlement Agreement, shown in Attachment A, embodied concepts that are different from what is contained in BPA's Amended Proposal. This Supplemental

Proposal represents a package that meets BPA's critical objectives as specified in the Amended Proposal and resolves most of the issues that rate case parties had with BPA's earlier proposal. By preparing this Supplemental Proposal, along with presenting the Partial Settlement Agreement, BPA can give rate case parties an indication of the effects of the lower starting reserves and higher market prices.

Q. *What is the general design of this Partial Settlement Agreement?*

A. The Partial Settlement Agreement is intended to serve as a basic understanding for an acceptable approach to resolving the cost recovery problem faced by BPA. The Supplemental Proposal is intended to serve as a means of implementing the objectives and intent outlined in the Partial Settlement Agreement. The Partial Settlement Agreement acknowledges that BPA staff would not use the exact language of the Exhibit A of the Partial Settlement Agreement when it developed this Supplemental Proposal. Time and other factors did not allow BPA staff and the parties to develop the Partial Settlement Agreement with the same detail as is embodied in the Supplemental Proposal. This level of detail is necessary to include, for example, in the General Rate Schedule Provisions. In the testimony of Lefler, *et al.*, WP-02-BPA-E-73, BPA staff describe how they embodied the intent of the Partial Settlement Agreement in specific language.

Section 3. Policy Objectives of the Supplemental Proposal

Q. *What policy objectives drove the Amended Proposal?*

A. We described in our December testimony supporting the Amended Proposal, the development of our policy objectives. (*See* Burns, *et al.*, WP-02-E-BPA-62, at 4.) They are restated here.

In BPA's August 31, 2000, letter to customers and interested parties, the BPA Administrator described the criteria BPA used to determine the appropriate approach to solving this cost-recovery problem. The criteria for the proposed solution were:

1. It should be as simple as possible;
2. It should allow Subscription contract signing to proceed to completion as soon as possible;
3. It should not require review or revision of the overall Subscription Strategy;
4. Specifically, reallocation of Subscription power among customer groups, or a change in the basic balance of interests in Subscription should not be required;
5. It should require limited revisions, if any, to the 2002 rate proposal currently before Federal Energy Regulatory Commission (FERC), and limited revisions, if any, to the Subscription contract; and
6. It must achieve the goal of leaving BPA's probability of repaying the U.S. Treasury, in full and on time, within an acceptable range over the 2002-2006 rate period.

Q. *What was the guidance you gave to staff redesigning the CRAC for the Amended Proposal?*

A. First, the CRAC, when combined with the other risk mitigation tools that are being modeled, should achieve a TPP that falls within the 80 to 88 percent range established by the Fish and Wildlife Funding Principles (Principles), specifically Principle No. 3.

Second, redesign of the CRAC should satisfy Principle No. 4.

Third, given that revenue requirements are not being revised, the CRAC, along with commensurate changes in the Slice, must remedy the under-recovery that results from the likelihood of purchasing more power at higher prices than assumed in the May Proposal.

Fourth, all other things being equal, BPA would prefer to utilize contingent measures to mitigate revenue and cost uncertainties because the expected value cost to ratepayers is lower. However, this must be balanced with tools that will avoid rate shocks resulting from frequent and significant changes to rates, potential customer problems of liquidity, and other implementation risks not captured in the risk analysis.

And finally, BPA sought to minimize the potential for contention and administrative burden during implementation of the CRAC. *See* Burns, *et al.*, WP-02-E-BPA-62, at 5.

Q. *Has this guidance changed?*

A. The guidance has been refined based on the nature of the Partial Settlement Agreement. We would still like to avoid rate shock, including the desire for rates that avoid frequent and significant changes, as described above. Given the size of the potential problem of high augmentation costs, almost any proposal BPA could put forward would have rate shock. However, as a result of discussions with rate case parties leading to the Partial Settlement, BPA and the parties agreed to a revision to the LB CRAC, which would create biannual rate level changes to deal with these augmentation costs. As a result of this, BPA will rely less on contingent measures. We believe that by having an LB CRAC which more closely matches our revenues to our augmentation costs, our proposal will still result in a rate design that results in the overall lowest expected value cost to ratepayers, while achieving our given TPP objectives.

Q. *You maintained BPA had not changed its cost recovery goal of 88 percent TPP in the Amended Rate Proposal. Is this also true for this Supplemental Proposal?*

A. Yes. BPA's goal continues to be an 88 percent probability that payments to Treasury be made on time and in full over the five-year rate period. *See* Volume 1 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, and the May Record of Decision (May ROD), at 7-7 through 7-10. As in the May and Amended Proposals, this

Supplemental Proposal continues to implement the Fish and Wildlife Principles in order to deal prudently with potential fish mitigation costs. The TPP in the Amended Proposal was 83.4 percent TPP. The range of TPPs for this Supplemental Proposal is from 82.7 percent to 85.9 percent, assuming that BPA's total Slice sales are 2,000 average megawatts (aMW). *See* Lefler, *et al.*, WP-02-E-BPA-73.

Q. *Why are you showing a range of TPP values instead of a single number?*

A. We are describing the Supplemental Proposal through the use of a set of analyses instead of a single analysis because of the design of the LB CRAC. The LB CRAC in this Proposal is a formula, rather than a percentage to be fixed in the Final Record of Decision (Final ROD). The formula is based on BPA's net cost of augmentation, which depends on the remaining augmentation need (*i.e.,* the augmentation need for which BPA does not have purchases in place), and a market-based forward indicator of future power prices. As we have noted above, in today's electricity world, future power prices can be highly volatile. In addition, the LB CRAC percentage may be large enough to induce some customers to reduce their BPA load. To avoid basing another proposal on a single estimate of forward prices and remaining augmentation, BPA is presenting a proposal developed with its customers in which the LB CRAC will adjust to market prices and BPA's augmentation needs. Since we cannot predict what the forward prices and remaining augmentation needs will be, we are presenting a range of possibilities.

Q. *With a TPP lower than 88 percent, does your proposal still meet the Principles?*

A. Yes. As with the 83.4 percent TPP in the Amended Proposal, the range of TPPs in this Supplemental Proposal falls within the 80 to 88 percent range allowed by Principle No. 3. The LB CRAC fluctuates as actual augmentation costs change, thereby mitigating that market risk. And as with our Amended Proposal, this proposal still includes the SN CRAC, which serves as additional assurance that payments to Treasury will be made, though it is not modeled in the TPP analysis.

In addition, this proposal yields expected values of ending reserves in FY 2006 of over $1 billion, even after taking into account the effect of the DDC, a result that BPA's May Proposal could not quantify. In the May Proposal, the likelihood that BPA would end 2006 with at least $500 million in reserves was approximately 75 percent. Now, the corresponding range of probabilities is approximately 78 to 85 percent (assuming 2,000 aMW of Slice sales). (*See* Lefler, *et al.*, WP-02-E-BPA-73).

Section 4. Summary of Major Changes in Supplemental Proposal

Q. What are the major changes in this Supplemental Proposal?

A. Consistent with the Partial Settlement Agreement, there are several changes reflected in this Supplemental Proposal. First, design changes are being proposed to each of the three CRACs, in particular the LB and FB CRACs. Second, there are changes to the threshold and other criteria for the DDC mechanism. Third, modifications are being proposed to the calculation of the financial portion of the Investor-Owned Utilities Residential Exchange Program Settlement (REP Settlement). Fourth, modifications are being proposed to the Slice "inventory solution" true-up costs. There are no changes being proposed to the calculations of the Direct Service Industry (DSI) rates, besides those mentioned later in this testimony.

Q. Please summarize the major changes to the three CRAC mechanisms.

A. This Supplemental Proposal retains the three-component CRAC structure (*i.e.*, LB CRAC, FB CRAC, and SN CRAC) that was the center of the Amended Proposal. However, BPA is proposing to modify each of them somewhat, to match the Partial Settlement Agreement.

We are proposing two major changes to the LB CRAC. First, going into successive six-month periods, the value of the LB CRAC will be based on a forecast of augmentation costs, (both market price and augmentation amounts). That forecast would be "trued-up" every six months, after-the-fact, based on actual augmentation costs and revised cost projections. Second, the preliminary LB CRAC amount, set in the final rate proposal, will be shaped to reflect the declining market forecasts. *See* Lefler, *et al.*, WP-02-E-BPA-73. As mentioned above, BPA's current forecasts are that market prices would be high in the first year of the rate period and decline by the last year of the rate period. *See* Conger, *et al.*, WP-02-E-BPA-71. The changes to the LB CRAC mean that it will be the primary risk mitigation tool dealing with one of our largest risks, BPA's augmentation costs.

The FB CRAC has reverted back to the May Proposal with two exceptions. First, in the first year the threshold amount has been lowered to Accumulated Net Revenues equal to $300 million in reserves and there is no cap on revenue increases other than this lower threshold. Second, if the FB CRAC triggers, it would be in effect for 12 months. It would be based on a third quarter forecast, and then be trued-up based on audited actuals when those actuals become available a few months later. *See* Lefler, *et al.*, WP-02-E-BPA-73.

The SN CRAC was revised so that it could trigger if there is a 50 percent probability of BPA missing a payment to the Treasury, <u>or</u> other creditor; or, alternatively, if BPA misses a payment to <u>either</u> the Treasury or other creditor. Second, in the Amended Proposal, BPA had proposed a public process, short of a 7(i) process, to implement the SN CRAC. This Supplemental Proposal, consistent with the Partial Settlement Agreement, proposes that BPA would conduct a 7(i) and seek FERC approval prior to the SN CRAC being implemented.

Q. *What changes are being proposed to the DDC?*

A. BPA is proposing three modifications to the DDC. First, beginning with the second year of the rate period, if a specific DDC threshold is met, all of the DDC amount (above the $15 million already committed to conservation and renewable resources) will automatically be distributed to customers and will no longer be discretionary on the part of the Administrator. Distributions will no longer be divided and allocated based on decisions in a later public process. Second, the thresholds will be fixed at $1.7 billion in reserves for the second year, $1.5 billion for the third year, and $1.2 billion for each of the last two years. These thresholds will be fixed, except in the event that BPA has outstanding expenses under the Biological Opinion. *See* Lefler, *et al.*, WP-02-E-BPA-73. Finally, as part of the Partial Settlement Agreement, BPA is proposing that the Financial portion of the REP Settlement Benefits be eligible for a portion of the DDC. *See* Lefler, *et al.*, WP-02-E-BPA-73.

Q. In the Partial Settlement Agreement, are there any other proposed changes to the Investor-Owned Utilities Residential Exchange Program Settlement?

A. Yes. In the Amended Proposal, BPA proposed a $34.1/MWh forecast for purposes of calculating the financial benefits under the REP Settlement. BPA now proposes an adjustment to this number.

Q. What is this adjustment?

A. As noted previously, BPA recently conducted settlement discussions with all interested parties in BPA's WP-02 rate case. As mentioned above, large number of those parties proposed a partial settlement of many rate case issues. One element of that proposal is that $38/MWh should be used in calculating the financial benefits under the REP Settlement, instead of the $34.1/MWh forecast in BPA's Amended Proposal. (BPA's testimony regarding the $34.1/MWh forecast is contained in the testimony of Doubleday, *et al.*, WP-02-E-BPA-65, and Doubleday, *et al.*, WP-02-E-BPA-74.) Where so many parties support $38/MWh as part of the Partial Settlement Agreement, this suggests that such parties believe that the $38/MWh is consistent with BPA's policy goal of "[s]preading[ing] the benefits of the Federal Columbia River Power System as broadly as possible, with special attention given to the residential and rural customers of the region." *See* Power Subscription Strategy, at 3.

When viewed in the context of the Partial Settlement Agreement, BPA believes that it is appropriate to adjust the forward five-year market forecast from $34.1/MWh to $38/MWh. BPA's $34.1/MWh forecast was developed at a time when market prices had increased significantly from market prices at the time of BPA's May Proposal. However, as noted in the testimony of Conger, *et al.*, WP-02-E-BPA-71, market prices have also increased significantly from the time of BPA's Amended Proposal. BPA has elected to make the adjustment to $38/MWh to reflect this observed price increase in the marketplace because this is consistent with BPA's policy goals as noted above. While BPA does not expect current prices to continue for the five-year period of the forward flat block forecast, BPA feels that current high market prices lasting through the first 6-18 months of the forecast period, viewed in the context of the Partial Settlement Agreement, justify an increase in the forward five-year market forecast price to $38/MWh.

Q. Is BPA proposing changes to the Slice methodology?

A. Yes. The Amended Proposal contained a mechanism to calculate the Slice purchasers' share of BPA's actual augmentation costs. Consistent with the Partial Settlement Agreement, BPA is revising the manner in which Slice purchasers will pay their proportionate share of augmentation costs.

Q. How will Slice purchases pay for their proportionate share of the augmentation costs?

A. BPA is now proposing that the Slice purchasers pay for augmentation in a fashion similar to the manner in which the LB CRAC is now being implemented (*see* Lefler, *et al.*, WP-02-E-BPA-73), with some minor changes in the design of the true-up due to the different nature of the product. (*See* Procter, *et al.*, WP-02-E-BPA-72).

Q. Are Slice purchasers now subject to the LB CRAC?

A. Yes. As a result of the agreements reached in the Partial Settlement Agreement, the manner in which Slice customers pay for their share of augmentation will mirror in the early part of the rate period. BPA understands the harmful impact that these large rate increases could have on the region. Therefore, we are committed to work to lower those augmentation costs including conservation efforts. We will work with customers to reduce the amount of augmentation purchases we must make. We will also work diligently to manage the purchases we must make, in order to get the best price we can.

In addition, if BPA is able to resolve cash flow issues, it may be able to restructure the LB CRAC to produce average LB CRAC increases, that is, a LB CRAC percentage that recovers the net augmentation costs for more than one year over a period of the same number of years. For example, there could be a single LB CRAC percentage for a two-year period that recovers BPA's net augmentation costs for that two-year period, with a true-up following.

Q. Does this conclude your testimony?

A. Yes.

almost all respects the design of the LB CRAC. Therefore, the Slice will now be subject to the LB CRAC, with some slight modifications. The LB CRAC adjustment will replace the previous method for the one-time megawatt (MW) true-up and the true-up for actual costs of augmentation. Slice will also continue to be exempt from the FB CRAC and the SN CRAC since the risks that those CRACs are designed to cover are already directly assumed by the Slice Customers. (*See* Lefler, *et al.*, WP-02-E-BPA-73). Slice continues to not be eligible for the DDC.

Q. *Are there any proposed changes to the rates to be charged the DSIs?*

A. No. The Industrial Firm Power Targeted Adjustment Charge rate will remain unchanged. The LB CRAC, FB CRAC, and SN CRAC will all apply to the DSI rates. And the DSIs will be eligible for the DDC. Of course, the CRACs are modified from the Amended Proposal, as described elsewhere in this testimony.

Q. *Are there any other significant changes that are being made in this Supplemental Proposal?*

A. Yes. As we mentioned above, BPA has noticed that market prices during the rate period are appearing to be significantly higher than our models would indicate in the first years of the rate period. In the testimony of Conger, *et al.*, WP-02-E-BPA-71, we describe the steps we have taken to calibrate our models to more closely match the observed market price levels.

Q. *What updates does BPA intend to include in the final proposal?*

A. Each piece of technical testimony identifies the particular information that would be updated. However, in particular, the augmentation cost inputs into the LB CRAC formula will be updated and shown in the final studies. BPA understands that given our current expectations of those augmentation costs, based on the amount of power we will need to purchase and the prices at which we may have to make these purchases, the LB CRAC formula has the potential of resulting in a very large rate increase, particularly in

ATTACHMENT A

PARTIAL STIPULATION E: SETTLEMENT AGREEMENT

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INDEX

TESTIMONY OF

SIDNEY L. CONGER, ARNOLD L. WAGNER, EDWARD L. BLEIFUSS, ROBERT J. PETTY, ROBERT W. ANDERSON, MARK H. EBBERTS, JON A. HIRSCH, ELIZABETH A. EVANS, CARL T. BUSKUHL, AND JEFFREY W. CHOW

Witnesses for Bonneville Power Administration

SUBJECT: Risk Analysis Study and No-Slice Risk Analysis

TESTIMONY OF

SIDNEY L. CONGER, ARNOLD L. WAGNER, EDWARD L. BLEIFUSS, ROBERT J. PETTY, ROBERT W. ANDERSON, MARK H. EBBERTS, JON A. HIRSCH, ELIZABETH A. EVANS, CARL T. BUSKUHL, AND JEFFREY W. CHOW

SUBJECT: RISK ANALYSIS STUDY AND NO-SLICE RISK ANALYSIS

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sidney L. Conger, Jr. My qualifications are contained in WP-02-Q-BPA-14.

A. My name is Arnold L. Wagner. My qualifications are contained in WP-02-Q-BPA-67.

A. My name is Edward L. Bleifuss. My qualifications are contained in WP-02-Q-BPA-04.

A. My name is Robert J. Petty. My qualifications are contained in WP-02-Q-BPA-58.

A. My name is Robert W. Anderson. My qualifications are contained in WP-02-Q-BPA-01.

A. My name is Mark H. Ebberts. My qualifications are contained in WP-02-Q-BPA-18.

A. My name is Jon A. Hirsch. My qualifications are contained in WP-02-Q-BPA-28.

A. My name is Elizabeth A. Evans. My qualifications are contained in WP-02-Q-BPA-69.

A. My name is Carl T. Buskuhl. My qualifications are contained in WP-02-Q-BPA-09.

A. My name is Jeffrey W. Chow. My qualifications are contained in WP-02-Q-BPA-71.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the Risk Analysis Study for the 2002 Supplemental Power Rate Proposal (Supplemental Proposal) and the No-Slice Risk Analysis performed in support of the Cost Shift Analysis for the Slice product. The Risk Analysis Study and the No-Slice Risk Analysis evaluate operating and non-operating risks that affect Bonneville Power Administration's (BPA) ability to make its annual U.S. Treasury payments on time and in full during the Fiscal Year (FY) 2002-2006 rate period. Operating risks include variations in economic, load, and generation resource conditions. These operating risks include the impact that spot market electricity prices, load levels, and resource output (including hydro generation under alternative hydro operations associated with the 13 fish and wildlife alternatives) have on net revenues. The impact of operating risks on BPA's net revenues is quantified by the Risk Model Analysis (RiskMod). *See* Risk Analysis Study and Study Documentation, WP-02-FS-BPA-03/03A. Non-operating risks include uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 fish and wildlife alternatives, uncertainty in achieving cost reductions from the Cost Review recommendations, costs associated with Business Line separation, costs associated with conservation and renewables, and interest rates. The impact of non-operating risks on BPA's net revenues is quantified by the Non-Operating Risk Model (NORM). *See* Risk Analysis Study and Study Documentation, WP-02-FS-BPA-03/03A.

Q. How is your testimony organized?

A. This testimony contains seven sections including this introductory section. Section 2 provides an overview of the changes in the Risk Analysis Study since the 2002 Amended Power Rate Proposal (Amended Proposal). Section 3 describes the changes in RiskMod and NORM since the Amended Proposal. Section 4 describes the changes in loads and resources since the Amended Proposal. Section 5 describes the changes in the natural gas price forecast since the Amended Proposal. Section 6 describes the changes in the AURORA model since the Amended Proposal. Finally, Section 7 describes the changes that BPA anticipates making to the Risk Analysis Study and the No-Slice Risk Analysis for the Final Record of Decision (Final ROD).

Section 2. Changes in the Risk Analysis Study Since the Amended Proposal

Q. *What changes have been made to the Risk Analysis Study since the Amended Proposal?*

A. The Risk Analysis Study for the Supplemental Proposal incorporates several changes from the Risk Analysis Study performed for the Amended Proposal. The changes include the following: (1) modeling and data changes in RiskMod; (2) revised resources and analysis using two load levels; (3) revised methodology for simulating Heavy Load Hour (HLH) and Light Load Hour (LLH) monthly electricity price risk for FY 2002 and 2003 at three price levels. *See* Chapter 2, 2002 Supplemental Power Rate Proposal Study, WP-02-E-BPA-67.

Section 3. Changes in Risk Model Analysis and the Non-Operating Risk Model Since the Amended Proposal

Q. What modeling and data changes have been made to RiskMod since the Amended Proposal?

A. Modeling and data changes in RiskMod are as follows: (1) revisions so that the Rate Case parties bear the risk of the amount and price of System Augmentation purchases, including the cost of serving the load growth and load variability of the Full and Partial Requirement customers; (2) revisions to calculate the net revenue impact of two load levels and three market prices; (3) removal of the computation of the cost of the Inventory Solution from the Slice Revenue Requirement in RiskMod; (4) capping the 4(h)(10)(C) credits at the amount of the annual Treasury Payments for FY 2002-2006; (5) revision of the expected FCCF reserve at the start of FY 2002 and (6) revisions of the expected Non-Treaty Storage level at the start of FY 2002.

Q. Why were these changes made to RiskMod?

A. As discussed in the testimony of Burns, *et al.*, WP-02-E-BPA-70, BPA and many rate case parties reached agreement on most of the rate case issues in the Partial Settlement Agreement. A key feature of the Partial Settlement Agreement is that BPA's power customers essentially bear the risk of the amount and price of System Augmentation purchases, including the costs of serving the load growth and load variability of the Full and Partial Requirements customers. This approach is a prudent means of dealing with the present market conditions. Therefore, RiskMod needed to be revised to account for this change.

Q. *Why was RiskMod revised so that BPA could calculate the net revenue impact of a range of alternative loads?*

A. As stated in Section 4 of the Testimony submitted by Burns, *et al.*, WP-02-E-BPA-70, BPA has indicated that it will work with its customers to reduce the amount of System Augmentation purchases that BPA must make. Also, BPA anticipates that there could be load responses to the possible large adjustments to rates anticipated in the Supplemental Proposal through the Load-Based Cost Recovery Adjustment Clause (LB CRAC). These load responses might reduce the amount of System Augmentation purchases and subsequently lower the LB CRAC rate. However, since BPA does not know how much load reduction there will be, it is appropriate to evaluate a range of alternative loads. As a result, RiskMod was revised to incorporate these possible outcomes when estimating net revenues.

Q. *Why did BPA remove the computation of the cost of the Inventory Solution from the Slice Revenue Requirement in RiskMod and incorporate this computation in the ToolKit Model?*

A. BPA removed the computation of the cost of the Inventory Solution from the Slice Revenue Requirement in RiskMod and incorporated this computation in the ToolKit Model so that the calculations of the LB CRAC for all parties are performed in the ToolKit model.

Q. In the Amended Proposal, BPA did not have caps on 4(h)(10)(C) credits. Why did BPA cap 4(h)(10)(C) credits at the amount of the annual Treasury Payments for FY 2002-2006 in RiskMod for the Supplemental Proposal?

A. BPA capped 4(h)(10)(C) credits at the amount of the annual Treasury Payments for FY 2002-2006 in RiskMod for the Supplemental Proposal for two reasons. First, unlike in the Amended Proposal, market price and market price risk for FY 2002 and 2003 are much higher resulting in the possibility of 4(h)(10)(C) credits exceeding the annual Treasury Payments. Secondly, BPA capped the 4(h)(10)(C) credits at the amount of the annual Treasury Payments because BPA is unsure whether or not it is possible to collect funds beyond the amount of the Treasury Payment. It would be imprudent to assume more can be collected until an agreement has been reached with the U.S. Treasury that states BPA can collect more.

Q. Why did BPA revise its estimate of the expected Fish Cost Contingency Fund (FCCF) reserve at the start of FY 2002 to a point estimate of $167 million for the Supplemental Proposal?

A. BPA revised the expected FCCF reserve at the start of FY 2002 to a point estimate of $167 million for the Supplemental Proposal because BPA now has better estimates of streamflow conditions and potential streamflow variability for FY 2001 than when the Amended Proposal was published.

Q. Why did BPA revise the expected Non-Treaty Storage level at the start of FY 2002 from 2,858 megawatts (MW)/months to 1,000 MW/months for the Supplemental Proposal?

A. For the Supplemental Proposal, BPA has updated its forecast based on information on anticipated storage and withdrawals of Non-Treaty Storage in light of current storage levels, projected streamflows, and current hydro operations that reflect the impact of the dry weather conditions in FY 2001, which differ from typical Non-Treaty storage levels under normal weather conditions. Consideration of these factors resulted in the adjustment of the expected Non-Treaty Storage level at the start of FY 2000 from 2,858 MW/months to 1,000 MW/months.

Q. BPA performed risk analyses for two load scenarios (0 and 1,500 load reduction) and three electricity price levels ($315/megawatthour (MWh), $210/MWh, and $140/MWh in FY 2002). What was the basis for BPA selecting these particular values?

A. The values selected were for illustrative purposes, but they were deemed to represent reasonable potential ranges.

Q. Since the Amended Proposal, what changes have been made to the Risk Simulation Models (RiskSim), which are a component of RiskMod?

A. BPA developed the Forward Market Price Simulator to simulate electricity prices and price variability for FY 2002 and FY 2003. This risk model simulates market price uncertainty using monthly forward market electricity prices and electricity price volatilities derived from option premiums (implied price volatilities).

Q. Why did BPA use the Forward Market Price Simulator to simulate electricity prices and price variability for FY 2002 and 2003?

A. BPA used the Forward Market Price Simulator to simulate electricity prices and price variability for FY 2002 and 2003 because BPA believes the methodology is the most appropriate methodology for simulating electricity prices under current market conditions (*See* Section 6 of this Testimony). The Forward Market Price Simulator simulates monthly forward market electricity prices. The Forward Market Price Simulator uses forward market prices at which traders are currently willing to buy and sell energy for different points in time in the future and the price volatility reflected in option premiums (referred to as implied price volatility) at which market participants are currently willing to buy and sell options for different points/periods in time in the future.

Q. *What is the implied volatility on forward electricity prices?*

A. Implied volatility is a measure of the expected future volatility of forward electricity prices and is stated as the annualized day-to-day percentage change in price as a normal distribution.

Q. *Why does BPA believe that the implied volatilities derived from currently traded options are a better reflection of future volatility than the volatility in historical market prices?*

A. BPA believes the implied volatilities derived from currently traded option premiums are a better reflection of estimated future volatility than using historical changes in price because the market is willing to trade on their belief of future volatility. Historical volatility, however, says nothing about the future; it can only reflect price levels that have traded in the past.

Q. *BPA describes in Section 2.2.7 of the 2002 Supplemental Power Rate Proposal Study (WP-02-E-BPA-67) a methodology for calibrating electricity prices estimated by AURORA to the electricity prices simulated by the Forward Market Price Simulator for FY 2002 and 2003. Why did BPA calibrate the prices estimated by AURORA to the results from the Forward Market Price Simulator, rather than just using the results from the Forward Market Price Simulator?*

A. There are two reasons why BPA calibrated the prices estimated by AURORA to the results from the Forward Market Price Simulator, rather than just using the results from the Forward Market Price. The Forward Market Price Simulator simulates electricity price variability for each month independent of the prices simulated for all other months. This yields prices simulated for each month that do not account for the dependency in monthly prices through time. In contrast, AURORA, which estimates monthly prices using fundamental market data that incorporates monthly dependencies, estimates prices through time that reflect dependency in monthly prices through time. Also, the monthly prices simulated for each month by the Forward Market Price Simulator are not tied to any market fundamentals such as the amount of hydro generation and level of loads. Accordingly, it would be inappropriate to calculate revenues and expenses in RiskMod using randomly simulated prices. By using the calibrated AURORA prices to estimate revenues and expenses in RiskMod, the dependency between hydro generation, load, and prices are maintained.

Q. Have there been any changes in NORM since the Amended Proposal?

A. No.

Section 4. Changes in Loads and Resources Since the Amended Proposal

Q. What changes have been made to Federal resources since the Amended Proposal?

A. BPA has revised the actual System Augmentation purchases that it has made since the Amended Proposal. Actual System Augmentation purchases used in RiskMod for the Amended Proposal amounted to 917 average megawatt (aMW)/year at a cost of $242.9 million/year ($30.20/MWh) and were based on all purchases as of October 23, 2000. *See* Tables 2-3 and 2-4 in the 2002 Amended Power Rate Proposal Study Documentation, WP-02-E-BPA-60. Actual System Augmentation purchases used in RiskMod for the Supplemental Proposal amount to 1,048 aMW/year at a cost of $280.5 million/year ($30.55/MWh) and were based on all purchases as of January 1, 2001. *See* Tables 2-1 and 2-2 in the 2002 Supplemental Power Rate Proposal Study, WP-02-E-BPA-67.

Q. Has BPA modified its public utility customer sales forecast from that presented in the Amended Proposal?

A. No, BPA has not modified its public utility customer sales forecast for this Supplemental Proposal. The sales forecast in the Amended Proposal was based on signed contracts. No changes in the status of those signed contracts have occurred as yet, and individual utility forecasts have not been modified.

Witnesses: Sidney L. Conger, Arnold L. Wagner, Edward L. Bleifuss, Robert J. Petty, Robert W. Anderson, Mark H. Ebberts, Jon A. Hirsch, Elizabeth A. Evans, Carl T. Buskuhl, and Jeffrey W. Chow

Q. Why did BPA analyze the impact of alternative load scenarios on BPA rates?

A. As stated in Section 3 of the Testimony submitted by Burns, *et al.*, WP-02-E-BPA-70, the LB CRAC employs a formula approach, rather than a fixed percentage specified in the Final ROD, and is subject to adjustment and true-up every six months, depending on the amount and price of System Augmentation purchases. The level of augmentation required, a major component of the cost of the LB CRAC, is a direct reflection of the level of sales projected. BPA is working with its customers to reduce the level of BPA System Augmentation needs. It is also possible that there will be a load response to the size of the LB CRAC being anticipated in the Supplemental Proposal. Therefore, an analysis of a range of loads is appropriate.

Q. Do you anticipate changing the sales forecast for the Final ROD?

A. Yes, it is likely that BPA will change the sales forecast for the Final ROD.

Section 5. Changes in the Natural Gas Price Forecast Since the Amended Proposal

Q. Are there any changes to the natural gas price forecast from the Amended Proposal?

A. No. The natural gas price forecast can be separated into two parts, a short-term forecast applied from FY 2000 to 2002, and a mid-term forecast for the years after 2002. The short-term forecast was tied to the New York Mercantile Exchange (NYMEX) futures contract for Henry Hub. The mid-term forecast was based solely on BPA analysis. BPA believes that the mid-term forecast is still valid. For the short-term, the NYMEX price has changed from the Amended Proposal. However, BPA is proposing a new method for calculating the short-term electricity market prices in which the natural gas price forecast is not a factor. Therefore, the short-term forecast is not relevant and was not updated.

Section 6. Changes in AURORA Since the Amended Proposal

Q. Has BPA made any changes to AURORA for the Supplemental Proposal?

A. No. For the Supplemental Proposal, BPA used another methodology described in Section 3 of this Testimony for estimating electricity prices and price variability for FY 2002 and 2003. BPA believes that the prices and price variability estimated by AURORA for FY 2004-2006 remain sound estimates. However, BPA may update the AURORA model to estimate prices and price variability for FY 2004–2006 in the Final ROD.

Q. Why did BPA decide not to use the price output from the AURORA for the first two fiscal years of the rate period?

A. BPA has witnessed market prices much higher in the near term than the AURORA model is forecasting. The AURORA model is an economic fundamentals based model. BPA believes that during normal market conditions, when loads and resources are in balance, the AURORA model is a reasonable model for forecasting prices. However, the current market conditions and prices reflect an extreme state of load and resource imbalance. In these extreme situations, a purely economic fundamentals based model may not adequately account for the market dynamics that can produce the very high prices currently being observed. During these situations, market quotes used in combination with statistical methods are a more appropriate way to simulate market prices.

Section 7. Anticipated Changes for the Final Amended Proposal

Q. Has BPA identified any changes that it anticipates making to the Risk Analysis Study for the Final ROD?

A. Yes, as indicated in Section 4 of this Testimony, BPA anticipates making revisions to its sales forecast. It is also very likely that BPA will be updating its electricity price forecast and estimates of market price variability.

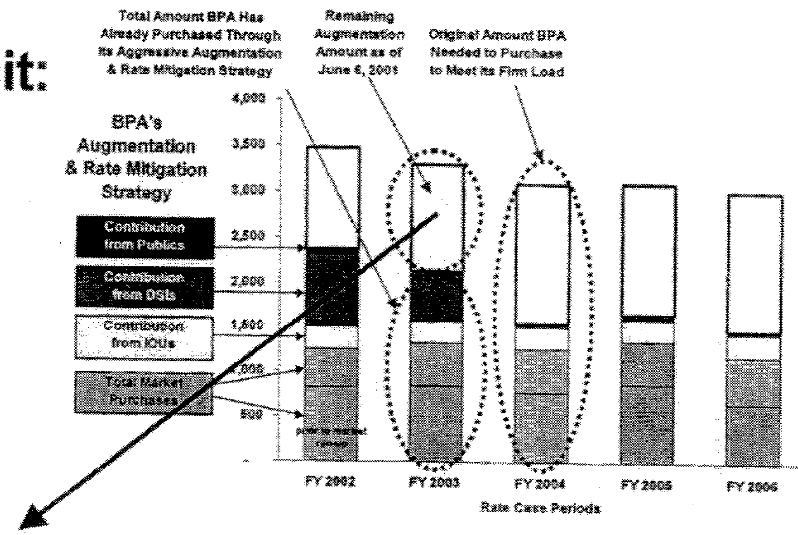
Q. *Are the changes that BPA has identified in this Testimony all the possible changes that BPA might make in the Risk Analysis Study for the Final ROD?*

A. No. BPA may make additional changes in the Risk Analysis Study for the Final ROD.

Q. *Does this conclude your testimony?*

A. Yes.

Filling the Remaining
Augmentation & Rate Mitigation Deficit:



Additional Contribution from Publics:

Seeking Over 500 aMW for FY 2002-03 Through
- Conservation
- Demand Response to Price
- Low-Cost Load Reduction Purchases
- Low-Cost Resource Purchases

Additional Contribution from DSIs:

Seeking Over 200 aMW for FY 2002-03 Through
- Demand Response to Price
- Low-Cost Load Reduction Purchases

Additional Contribution from IOUs:

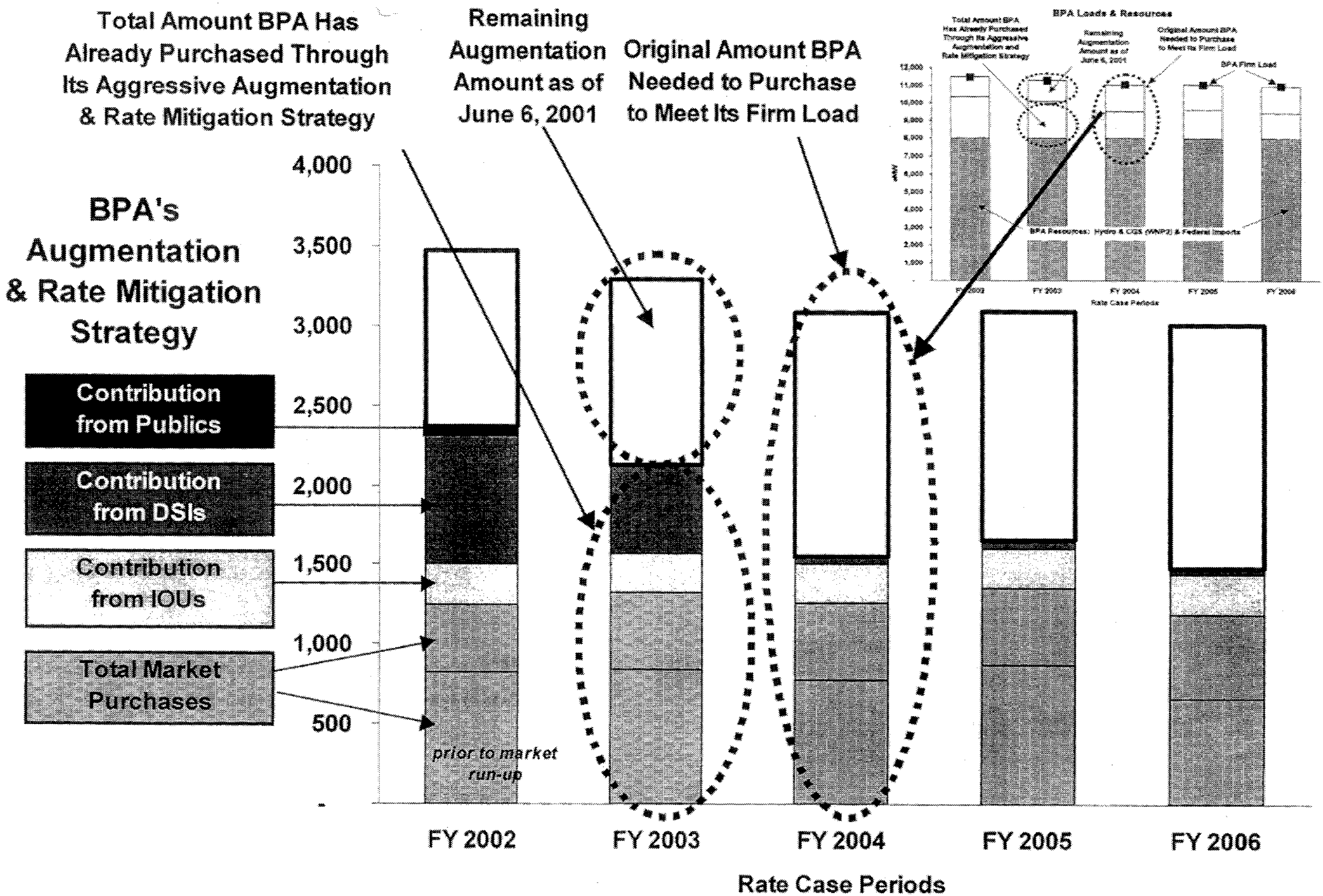
Seeking Over 75 aMW for FY 2002 Through
- Low-Cost Load Reduction Purchases

Seeking 370 aMW for FY 2002-06 Through
- Market-Based Load Reduction Purchases

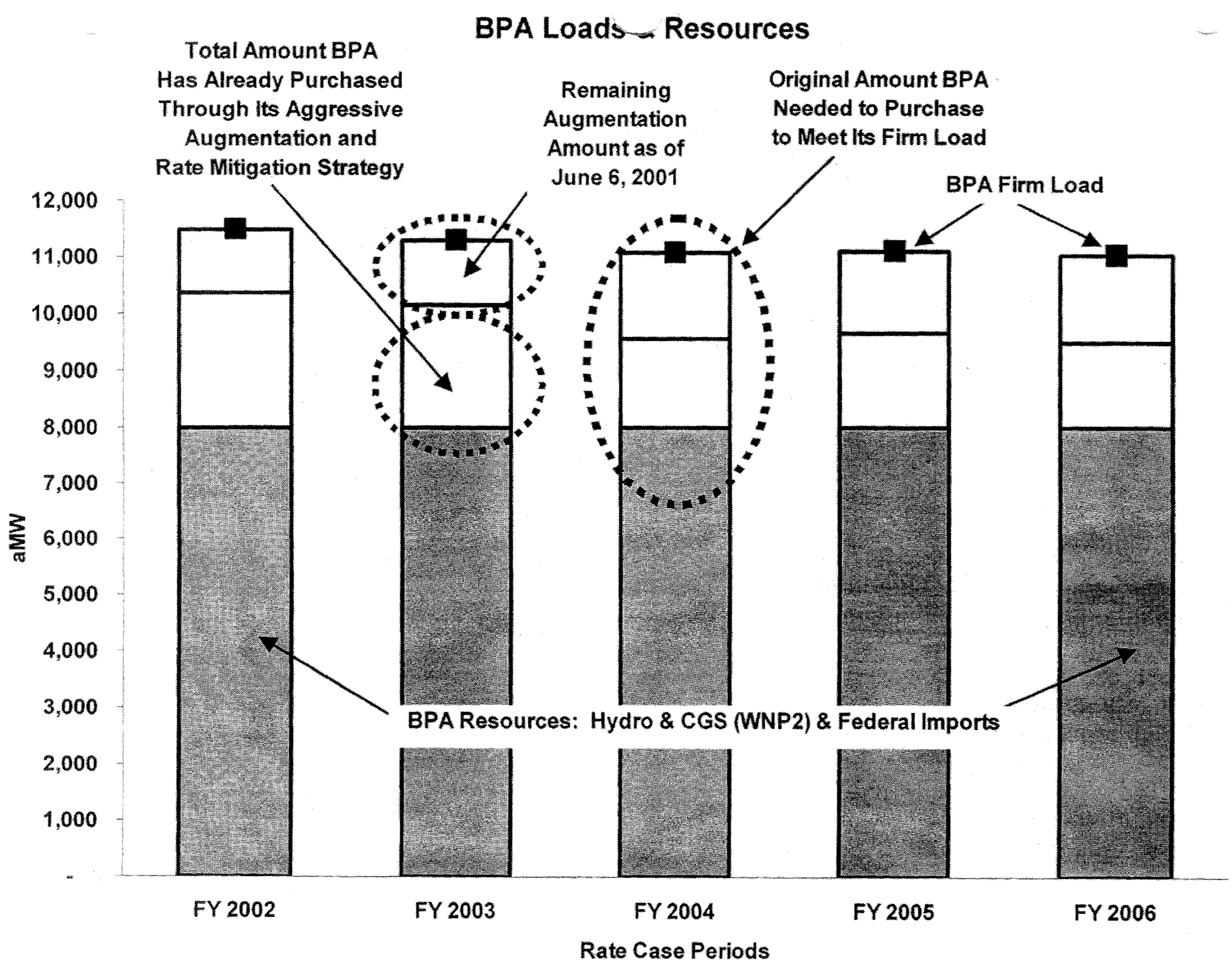
Additional Market Purchases:

No Additional Market Purchases for FY 2002-03

For FY 2004-06, Manage Deficits By:
- Focusing on New Renewables Development for FY 2003 and beyond - Over 500 aMW
- Leaving Part of Deficit Unfilled to Capture Market Downturn
- Leaving Part of Deficit Unfilled to Assess Pace of DSI Load Returning to BPA
- Exploring Purchases from New Gas-Fired Resources
- Developing a Comprehensive Hedging Strategy

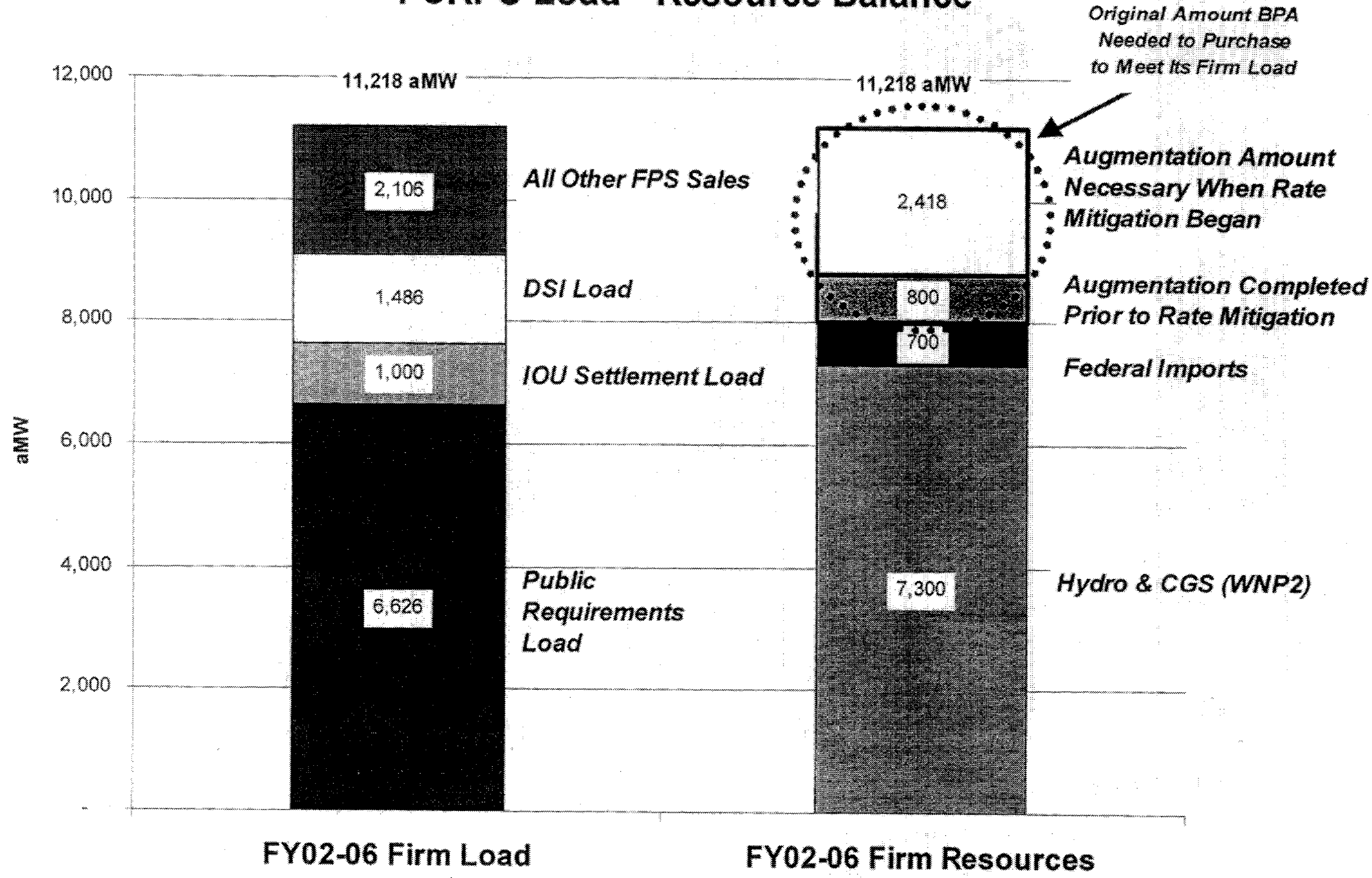


BPA's Augmentation & Rate Mitigation Strategy
Total Amount BPA Has Already Purchased Through Its Aggressive Augmentation & Rate Mitigation Strategy
Remaining Augmentation Amount as of June 6, 2001
Original Amount BPA Needed to Purchase to Meet Its Firm Load
Contribution from Publics
Contribution from DSIs
Contribution from IOUs
Total Market Purchases
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
prior to market run-up
FY 2002
FY 2003
FY 2004
FY 2005
FY 2006
Rate Case Periods
BPA Loads & Resources
BPA Firm Load
BPA Resources: Hydro & CGS (WNP2) & Federal Imports



BPA Loads & Resources
Total Amount BPA Has Already Purchased Through Its Aggressive Augmentation and Rate Mitigation Strategy
Remaining Augmentation Amount as of June 6, 2001
Original Amount BPA Needed to Purchase to Meet Its Firm Load
BPA Firm Load
BPA Resources: Hydro & CGS (WNP2) & Federal Imports
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
aMW
FY 2002
FY 2003
FY 2004
FY 2005
FY 2006
Rate Case Periods

FCRPS Load - Resource Balance



BPA's Peaking Resource Strategy
March 21, 2001

Synopsis: As a part of our augmentation strategy BPA is currently pursuing peaking resources that will come on line during the first 6 months of Subscription. These units have higher heat rates than we previously considered when pursuing combined cylcle CTs but they have significantly more operational flexibility and are available sooner.

How many Megawatts: 200-300 aMW total

Heat Rates: 9,000-11,000 MM btu/kwh

Costs:
Total Cost: Under $80 Mwh (If run whenever available with $5 gas)
Gas Cost: $45 - $55 with current $5 gas.

Benefits
Flexibility. Can be turned on and off hourly providing significant operational flexibility to shut down or ramp up on short notice. BPA could also sell some of this flexibility by selling options to recoup some of our fixed costs.
Available Early in Subscription. Projected to be on-line January to February 2002, earlier than combined cycle CTs will be available.
Hedge Against High Markets. If markets take longer to settle to rational levels than currently projected, the benefits of these units increase.

Key Risks
- *Unit Contingent.* Power is unit contingent and won't be available if the plant breaks down
- *Gas.* BPA takes on risk associated with the gas prices. We plan to hedge this risk but dealing in the gas arena is a new venture for BPA.
- *Future Market Prices.* Lower market prices in later Subscription years might make these look expensive then.

Specific Projects
- *Avista-Longview.* We have signed a nonbinding letter of intent for two 45 MW LM6000 CTs that would come on-line February 2002. We are beginning contract discussions and expect to conclude those by May.
- *GoldenNorthwest Projects.* In early discussions to buy output from 4 LM6000 units from Brett Wilcox. These are a part of Brett's plan to proactively create long-term power options for his aluminum plants. Just started discussions a couple of weeks ago but negotiations could move fairly quickly.
- *Marson Energy.* In this project BPA would purchase 5 years of capacity from small portable gas distributed generation and place them in 24 MW groups on customer sites. The logistics of procuring sites, gas and managing these generators in the midst of current staff overload may make these unattainable for BPA as we concentrate on bigger megawatt chunks such as IOU and DSI buy-downs. Customers have responded positively in providing sites . A BPA go/no go decision on this project will occur in mid April at the Energy Web Steering Committee.

FINANCIAL SETTLEMENT AGREEMENT AND AMENDMENT TO RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT WITH PACIFICORP

RECORD OF DECISION

Bonneville Power Administration
U.S. Department of Energy

May 23, 2001

Record of Decision

Financial Settlement Agreement and Amendment to Residential Exchange Program Settlement Agreement With PacifiCorp

INTRODUCTION

This Record of Decision addresses the development of an amendment to the Residential Exchange Program Settlement Agreement between PacifiCorp and the Bonneville Power Administration (BPA), Contract No. 01PB-12229, executed in October 2000, and the coincident development of a separate Financial Benefits Agreement, in order to provide financial benefits to the residential and small farm consumers of PacifiCorp through a settlement of PacifiCorp's participation in the Residential Exchange Program (REP) for the period from July 1, 2001, through September 30, 2006. 16 U.S.C. § 839c(c). In order to fully understand the proposed amendment and financial agreement with PacifiCorp, it is helpful to understand BPA's initial development of the REP Settlements with regional investor-owned utilities (IOUs). A review of such development follows.

BACKGROUND

BPA was created in 1937 to market electric power generated at Bonneville Dam, and to construct and operate facilities for the transmission of power. 16 U.S.C. § 832-832l (1994 & Supp. III 1997). Since that time, Congress has directed BPA to market power generated at additional facilities. *Id.* § 838f. Currently, BPA markets power generated at thirty Federal hydroelectric projects, and several non-Federal projects. BPA also owns and operates approximately 80 percent of the Pacific Northwest's high-voltage transmission system. In 1974, BPA became a self-financed agency that no longer receives annual appropriations. *Id.* § 838i. BPA's rates must therefore produce sufficient revenues repay all Federal investments in the power and transmission systems, and to carry out BPA's additional statutory objectives. *See id.* §§ 832f, 838g, 838i, and 839e(a).

In the 1970's, threats of insufficient resources to meet the region's electricity demands led to passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839, *et seq.* (1994 & Supp. III 1997). In that Act, Congress, among other things, directed BPA to offer new power sales contracts to its customers. *Id.* §§ 839c, 839c(g). While Congress provided that BPA's public agency customers (preference customers) and investor-owned utility customers (IOUs) had a statutory right for service from BPA to meet their net requirements loads, Congress did not provide such a right to BPA's direct service industrial customers (DSIs). BPA was provided the authority, but not the obligation, to serve the DSIs' firm loads after the expiration of their power sales contracts in 2001. *See id.* §§ 839c(b)(1), 839d. Congress also established the Residential Exchange Program, which, as discussed in greater detail below, provides Pacific Northwest utilities a form of access to the benefits of low-cost Federal power. *Id.* § 839c(c).

A. The Residential Exchange Program (REP)

Section 5(c) of the Northwest Power Act established the REP. *Id.* § 839c(c). Under the REP, a Pacific Northwest electric utility (either a publicly owned utility, an IOU or other entity authorized by state law to serve residential and small farm loads) may offer to sell power to BPA at the utility's average system cost (ASC). *Id.* § 839c(c)(1). BPA purchases such power and, in exchange, sells an equivalent amount of power to the utility at BPA's PF Exchange rate. *Id.* The amount of the power exchanged equals the utility's residential and small farm load. *Id.* In past practice, no actual power sales have taken place. Instead, BPA provided monetary benefits to the utility based on the difference between the utility's ASC and the applicable PF Exchange rate multiplied by the utility's residential load. These monetary benefits must be passed through directly to the utility's residential and small farm consumers. *Id.* § 839c(c)(3). While REP benefits have previously been monetary, the Northwest Power Act also provides for the sale of actual power to exchanging utilities in specific circumstances. Pursuant to section 5(c)(5) of the Northwest Power Act, in lieu of purchasing any amount of electric power offered by an exchanging utility, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to the utility as part of an exchange sale. *Id.* § 839c(c)(5). However, the cost of the acquisition must be less than the cost of purchasing the electric power offered by the utility. *Id.* In these circumstances, BPA acquires power from an in lieu resource and sells actual power to the exchanging utility.

Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers and other regional parties. A utility's ASC is the sum of a utility's production and transmission-related costs (Contract System Costs) divided by the utility's system load (Contract System Load). A utility's system load is the firm energy load used to establish retail rates. BPA's current ASC Methodology was established in 1984. BPA has recognized, however, that the ASC Methodology can be revised. BPA's current ASC Methodology uses a "jurisdictional approach" in determining utilities' ASCs, which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. These data provide the starting point for BPA's determination of the ASC of each utility participating in the REP. Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs.

The schedule for filing and reviewing a utility's ASC is established in the 1984 ASC Methodology, which provides that "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the utility shall file a preliminary Appendix 1, setting forth the costs proposed by the utility and shall deliver to BPA all information initially provided to the state commission." The filing includes all testimony and exhibits filed in the retail rate proceeding. Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. BPA then has 210 days to review the filing and issue a report signed by the Administrator. During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. BPA makes adjustments as necessary.

The REP has traditionally been implemented through Residential Purchase and Sale Agreements (RPSAs), which were executed in 1981. Between 1981 and the present, Residential Exchange Termination Agreements have been negotiated with all of the previously active exchanging utilities except Montana Power Company (MPC). MPC continues to be in "deemer" status. When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. By doing so, it avoids making actual monetary payments to BPA. The amount that the utility would otherwise pay BPA is tracked in a "deemer account." At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA under an existing or new RPSA. The issue of deemer balances with IOUs is currently in dispute. Regional utilities are eligible to participate in the REP again beginning July 1, 2001, except for those utilities that have previously executed settlement agreements for terms extending beyond July 1, 2001.

B. The Comprehensive Review of the Northwest Energy System

In early 1996, the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. *See* Comprehensive Review of the Northwest Energy System, Final Report, December 12, 1996 (Final Report). The governors appointed a 20-member Steering Committee that was broadly representative of the various stakeholders in the power system to study that system and make recommendations about its transformation. *Id.* Each governor had a representative on the Steering Committee to make certain the public was educated about and involved in the Comprehensive Review. *Id.* In establishing the review, the governors stated:

The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same tine assuring the region of an adequate, efficient, economical and reliable power system.

Id. In 1996, the Steering Committee held 30 daylong meetings. *Id.* In addition, almost 400 people were involved in more than 100 meetings of various work groups reporting to the Steering Committee. *Id.* Hundreds of citizens attended the 10 public hearings that were held throughout the region on the Committee's draft report. *Id.* More than 700 written comments were received. *Id.* The Final Report was the product of that work. *Id.*

The Final Report noted that the electricity industry in the United States is in the midst of significant restructuring. *Id.* This restructuring is the product of many factors, including national policy to promote a competitive electricity generation market and state initiatives in California, New York, New England, Wisconsin and elsewhere to open retail electricity markets to competition. *Id.* This transformation is moving the industry away from the regulated monopoly structure of the past 75 years. *Id.* Today the region is served by individual utilities, many of which control everything from the power plant to the delivery of power to the region's homes or businesses. *Id.* In the future, the region may have a choice among power suppliers that deliver their product over transmission and distribution systems that are operated independently as common carriers. *Id.* There is much to be gained in this transition. *Id.* Broad competition in the electricity industry that extends to all consumers could result in lower prices and more choices about the sources, variety and quality of their electrical service. *Id.*

The Final Report also noted that there are risks inherent in the transition to more competitive electricity services. *Id.* Merely declaring that a market should become competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared. *Id.* It is entirely possible to have deregulation without true competition. *Id.* Similarly, the reliability of the region's power supply could be compromised if care is not taken to ensure that competitive pressures do not override the incentives for reliable operation. *Id.* How competition is structured is important. *Id.* It is also important to recognize the limitations of competition. *Id.* Competitive markets respond to consumer demands, but they do not necessarily accomplish other important public policy objectives. *Id.* The Northwest has a long tradition of energy policies that support environmental protection, energy-efficiency, renewable resources, affordable services to rural and low-income consumers, and fish and wildlife restoration. *Id.* These public policy objectives remain important and relevant. *Id.* The Final Report states that given the enormous economic and environmental implications of energy, these public policy objectives need to be incorporated in the rules and structures of a competitive energy market. *Id.*

The Final Report stated that, in some respects, the transition to a competitive electricity industry is more complicated in the Northwest because of the presence of BPA. *Id.* BPA is a major factor in the region's power industry, supplying, on average, 40 percent of the power sold in the region and controlling more than half the region's high-voltage transmission. *Id.* BPA benefits from the fact that it markets most of the region's low-cost hydroelectric power. *Id.* It is hampered by the fact that it has high fixed costs, including the cost of past investments in nuclear power and the majority of the costs for salmon recovery. *Id.* As a wholesale power supplier, BPA is already fully exposed to competition and is struggling to reduce its costs so that it can compete in the market. *Id.* The transition to a competitive electricity industry raises many issues for the BPA and the region. *Id.* In the near term, how can BPA continue to meet its financial and environmental obligations in the face of intense competitive pressure? *Id.* In the longer-term, when market prices rise and some of BPA's debt obligations have been retired, how can the Northwest retain the economic benefits of its low-cost hydroelectric power when the rest of the country is paying market prices? *Id.* And finally, what is the appropriate role of a Federal agency in a competitive market? *Id.*

The Final Report noted that while participants on the Comprehensive Review Steering Committee represented, by design, many divergent interests, they were fundamentally interconnected through one unifying value. *Id.* Collectively, they share an abiding interest in the stewardship of a great regional resource -- the Columbia River and its tributaries. *Id.* The river is the link that brought all the parties together and unites them in a single, overriding goal. *Id.* That goal is to protect and enhance the assets of this great natural resource for the people of the Pacific Northwest. *Id.*

The Final Report stated that the Federal power system in the Pacific Northwest has conferred significant benefits on the region for more than 50 years. *Id.* The availability of inexpensive electricity at cost has supported strong economic growth and helped provide for other uses of the Columbia River, such as irrigation, flood control and navigation. *Id.* The renewable and non-polluting hydropower system has helped maintain a high quality environment in the region. *Id.* But while the power system has produced significant benefits, these benefits came at a substantial cost to the fish and wildlife resources of the Columbia River basin. *Id.* Salmon and steelhead populations had been reduced to historic lows, and many runs were about to be listed under the Federal Endangered Species Act. *Id.* Resident fish and wildlife populations had also been affected. *Id.* Native Americans and fishery-dependent communities, businesses and recreationists had suffered substantial losses due in significant part to construction and operation of the power system. *Id.* The region's ability to sustain its core industries, support conservation and renewable resources, and restore salmon runs would be clearly threatened if the region cannot reach a consensus regional position to bring to the national electricity restructuring debate. *Id.* Without a sustainable and financially healthy power system, funding for fish and wildlife restoration could be jeopardized. *Id.*

The Final Report noted that the Governors of Idaho, Montana, Oregon and Washington, in their charge to the Comprehensive Review, and the Steering Committee in their deliberations, recognized that the electricity industry is changing, whether the region likes it or not. *Id.* The Comprehensive Review was not an initiation of change, but a response to change. *Id.* It was an effort to shape that change, to the extent shaping is possible, to ensure that the potential benefits of competition are achieved and equitably shared, environmental goals are met, and the benefits of the hydroelectric system are preserved for the Northwest. *Id.* The region's ability to shape the change in the Northwest electricity industry depends on its ability to develop a regional consensus. *Id.* If the Comprehensive Review failed to result in a consensus for regional action, the electricity industry would still be restructured. *Id.* A return to the historical industry structure is not an option. *Id.* Many of the comments received during the public hearing process on the Steering Committee's draft recommendations made it clear that this was not a widely appreciated fact. *Id.*

The Final Report summarized the Steering Committee's goals and proposals. The Steering Committee's goals for Federal power marketing were to: (1) align the benefits and risks of access to existing Federal power; (2) ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists while not compromising the security or tax-exempt status of BPA's third-party debt; and (3) retain the long-term benefits of the system for the region. *Id.* The recommendation was also intended to be consistent with emerging competitive markets and regional transmission solutions. *Id.* The mechanism proposed to accomplish these goals was a subscription system for purchasing specified amounts of power at cost with incentives for customers to take longer-term subscriptions. *Id.* Public utility customers with small loads would be able to subscribe under contracts that would accommodate minor load growth. *Id.* Subscriptions would be available first to regional customers a specified multiparty priority order, starting with preference customers, then the DSIs and the residential and small farm customers of the IOUs participating in the REP, followed by other regional customers. *Id.* Non-regional customers could subscribe after in-region customers. *Id.* Within each phase of the subscription process, longer-term contracts would have priority over shorter-term contracts if the system were oversubscribed. *Id.*

With regard to the REP, the Final Report noted that as a result of the Northwest Power Act, Northwest utilities have the right to sell to BPA an amount of power equal to that required to serve their residential and small farm customers at the utilities' average system costs and receive an equal amount of power at BPA's average system cost. *Id.* In reality, this is an accounting transaction. *Id.* No power is actually delivered. *Id.* This was intended to be a mechanism to share the benefits of the low-cost Federal hydropower system with the residential and small farm customers of the region's IOUs. *Id.* As a result of decisions made by BPA in its 1996 rate case, those benefits were reduced. *Id.* The Steering Committee acknowledged that the residential and small farm consumers of exchanging IOUs would be adversely affected by the reduction of exchange benefits. *Id.* Congress intervened for one year to stabilize the exchange benefits. *Id.* However, on October 1, 1997, there would be rate increases to the residential and small farm customers of the exchanging utilities. *Id.* The Steering Committee encouraged the parties to continue settlement discussions and to explore other paths to ensure that residential and small farm loads receive an equitable share of Federal benefits. *Id.*

C. BPA's Power Subscription Strategy

The concept of power subscription came from the Comprehensive Review of the Northwest Energy System, which, as noted above, was convened by the governors of Idaho, Montana, Oregon, and Washington to assist the Northwest through the transition to competitive electricity markets. The goal of the review was to develop recommendations for changes in the region's electric utility industry through an open public process involving a broad cross-section of regional interests. In December 1996, after over a year of intense study, as noted above, the Comprehensive Review Steering Committee released its Final Report. The Final Report recommended that BPA capture and deliver the low-cost benefits of the Federal hydropower system to Northwest energy customers through a subscription-based power sales approach. In early 1997, the

Governor's representatives formed a Transition Board to monitor, guide, and evaluate progress on these recommendations.

Public process is integral to BPA's decisionmaking. With the changing marketplace for electric power, there is considerable regional interest in defining how and to whom the region's Federal power should be sold. The public was involved at several levels during the development of BPA's Power Subscription Strategy. In addition to the public meetings held specifically on Subscription, BPA sought input from a wide range of interested and affected groups and individuals. BPA collaborated with Northwest Tribes, interest groups, Congressional members, the Department of Energy (DOE), the Administration, and BPA's customers to resolve issues, understand commercial interests, and develop strong business relationships.

In early 1997, BPA and the Pacific Northwest Utilities Conference Committee (PNUCC) invited 2800 interested parties throughout the Pacific Northwest to help further define Subscription. The collaborative effort to design a Subscription contract process began with a public kickoff meeting on March 11, 1997. At this meeting, a BPA/customer design team presented a proposed work plan, including a description of the environmental coverage for Subscription. An important element of the work plan was the formation of a Subscription Work Group. The Work Group, which normally met in Portland twice a month from March 1997 through September 1998, was open to the public. On average, 40-45 participants--representing customers, customer associations, Tribes, State governments, public interest groups, and BPA--attended. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation.

Over 18 months, BPA, its customers and other interested parties discussed and clarified many Subscription issues. During this time, BPA and the public confirmed goals, defined issues, developed an implementation process for offering Subscription, and developed proposed product and pricing principles. The following is a chronology of events.

On March 11, 1997, a public meeting was held in Portland to kick off the Federal Power Marketing Subscription development process. The following topics were discussed at this meeting: the role of the Regional Review Transition Board in the Subscription process; the Draft Work Plan that was developed to guide the development process; the issues that relate to the Subscription process that need to be addressed; and the National Environmental Policy Act (NEPA) strategy for this effort. The Work Plan identified a "self-selected" work group to lead this effort (anyone eligible to participate).

On March 18, 1997, a "Federal Power Marketing Subscription" web site was established at BPA to help disseminate information about the Subscription Process.

On March 19, 1997, the Federal Power Subscription Work Group held its first meeting in Portland, Oregon. The Work Group held a total of 33 meetings (approximately two per month), ending on September 22, 1998.

On September 9, 1997, a Progress Report was presented to the Transition Board.

On November 25, 1997, an update meeting for stakeholders was held in Spokane to discuss progress to date and next steps. A summary of the meeting, along with the meeting handout/slide presentation and concerns/issues raised, was posted to the web site.

In January 1998, an article entitled "*Subscription Process Underway*" was published in the BPA Journal, (January 1998).

On April 30, 1998, BPA's Power Business Line (PBL) established a web site to disseminate information about a customer group's Slice of the System Proposal. The Subscription Work Group evaluated the Slice proposal, and the proposal as modified by BPA continued to be developed in a subgroup through January 1999. BPA's pricing of the Slice product was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's Record of Decision (ROD), WP-02-A-02.

In June 1998, as part of the Issues '98 process, BPA published Issues '98 Fact Sheet #3: Power Markets, Revenues, and Subscription. Issues '98 (June/Oct. 1998). The fact sheet discussed implementation approaches being considered by the Subscription Work Group so participants in the Issues '98 process could comment. As part of Issues '98 BPA conducted a series of meetings around the region. Issues related to Subscription were key topics in the discussions at those meetings. The public comment period for Issues '98 closed June 26, 1998.

On June 8, 1998, BPA's PBL established a web site to disseminate information about development of the power rates that would be used in the Subscription contracts beginning October 1, 2001. Preliminary discussions regarding development of the power rates occurred in a series of informal public meetings and continued in workshops before BPA's initial proposal was published in early 1999.

On June 18, 1998, the third Subscription public meeting was held in Spokane to present, discuss, and collect comments on the various components related to Subscription. The meeting slide presentation and summary of the meeting were posted to the web site.

On September 18, 1998, BPA released its Power Subscription Strategy Proposal for public comment. Accompanying the proposal was a press release entitled "Spreading Federal Power Benefits" and a Keeping Current publication entitled "Getting Power to the People of the Northwest, BPA's Power Subscription Proposal for the 21st Century." Keeping Current (Sept. 1998). On September 25th, an electronic version of the BPA Power Product Catalog was posted to the web site.

On September 22, 1998, the Federal Power Subscription Work Group held its final meeting in Portland, Oregon.

Subscription issues were discussed at the "Columbia River Power and Benefits" conference on September 29, 1998, in Portland, Oregon. Over 250 people attended. Conference notes were posted to BPA's web site.

On September 30, 1998, BPA's Energy Efficiency organization established a web site to help disseminate information on the proposal for a Conservation and Renewable Discount. Development of the discount continued in a series of meetings through January 1999. Development of the discount was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's ROD, WP-02-A-02.

The public was invited to participate in two comment meetings on the Subscription Proposal; one in Spokane, Washington, on October 8, 1998; the other in Portland, Oregon, on October 14.

BPA developed the Power Subscription Strategy Proposal after considering the efforts of the Subscription Work Group, public comments on Subscription, and the broad information from Issues '98. The Proposal incorporated the information received from customers, Tribes, fish and wildlife interest groups, industries and other constituents. It laid out BPA's strategy for retaining the benefits of the Federal Columbia River Power System (FCRPS) for the Pacific Northwest after 2001. The comment period on the proposal closed October 23, 1998, although all comments received after that date were considered in the Power Subscription Strategy ROD and the NEPA ROD.

During the spring and summer of 1998, BPA conducted extensive public meetings with all interested parties regarding the development of BPA's Power Subscription Strategy. At the conclusion of these lengthy discussions, on September 18, 1998, BPA released a Power Subscription Strategy Proposal for public review. During the comment period BPA received nearly 200 responses to the proposal comprising nearly 600 pages of comments. After review and analysis of these comments, BPA published its final Power Subscription Strategy on December 21, 1998. *See* Power Subscription Strategy, and Power Subscription Strategy, Administrator's ROD. At the same time, the Administrator published a National Environmental Policy Act (NEPA) ROD that contained an environmental analysis for the Power Subscription Strategy. This NEPA ROD was tiered to BPA's Business Plan ROD (August 15, 1995) for the Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995). The purpose of the Subscription Strategy is to enable the people of the Pacific Northwest to share the benefits of the FCRPS after 2001 while retaining those benefits within the region for future generations.

The Subscription Strategy also addresses how those who receive the benefits of the region's low-cost Federal power should share a corresponding measure of the risks. The Subscription Strategy seeks to implement the subscription concept created by the Comprehensive Review in 1996 through contracts for the sale of power and the distribution of Federal power benefits in the deregulated wholesale electricity market. The success of the Subscription process is fundamental to BPA's overall business purpose to provide public benefits to the Northwest through commercially successful businesses.

The Subscription Strategy is premised on BPA's partnership with the people of the Pacific Northwest. BPA is dedicated to reflecting their values, to providing them benefits and to expanding and spreading the value of the Columbia River throughout the region. In this respect, the Strategy had four goals:

> Spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region;
>
> Avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions;
>
> Allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and
>
> Provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies.

The Power Subscription Strategy describes BPA decisions on a number of issues. These include the availability of Federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. The Power Subscription Strategy discussed some issues that would not be finally decided in the Strategy. Most of these issues were decided in BPA's 2002 power rate case, although some were decided in other forums, such as the transmission rate case, which concluded recently. For example, while the Strategy documents BPA's intention to implement a rate discount for conservation and renewable resources, the final design of that discount was developed in BPA's 2002 power rate case. Other issues to be decided in the 2002 power rate case include the design and application of the CRAC, which rates apply to which sales, and the design of the Low Density Discount (LDD). Customers raised issues regarding the application of other customers' non-Federal resources to serve regional load. These resource issues involve factual determinations under section 3(d) of the Act of August 31, 1964, P.L. 88-552 (Regional Preference Act), and section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), which BPA could not address in the Power Subscription Strategy and which were not made a part of the decisions in the Subscription Strategy ROD.

While BPA's Power Subscription Strategy did not establish any rates or rate designs, rate design approaches identified in the Power Subscription Strategy were part of BPA's initial power rate proposal, which was published in 1999. The comments received during the Subscription public process regarding the various rate-related issues were addressed in BPA's 2002 power rate case, which included extensive opportunities for public involvement.

BPA's Power Subscription Strategy provided a framework for the 2002 power rate case and Subscription power sales contract negotiations. The Subscription window was to remain open 120 days after the 2002 Final Power Rate Proposal, Administrator's ROD, was signed by the BPA Administrator, providing relatively certain information to potential purchasers regarding rates.

One element the Power Subscription Strategy proposal was a settlement of the REP for regional IOUs for the post-2001 period. The Power Subscription Strategy proposed that IOUs may agree to a settlement of the REP in which they would be able to receive benefits equivalent to a purchase of a specified amount of power under Subscription for their residential and small farm consumers at a rate expected to be approximately equivalent to the PF Preference rate. Under the proposed settlement, residential and small farm loads of the IOUs would be assured access to the equivalent of 1,800 aMW of Federal power for the FY 2002-2006 period and 2,200 aMW of Federal power for the FY 2007-2011 period.

The Power Subscription Strategy noted that BPA would set the physical and financial components of the Subscription amount, by year, in the negotiated Subscription settlement contracts. Any cash payment would reflect the difference between the market price of power forecasted in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads would be in equal hourly amounts over the period.

The Power Subscription Strategy proposed that BPA would offer five-year and 10-year Subscription settlement contracts for the IOUs. Under both contracts, the Subscription Strategy proposed that BPA would offer and guarantee 1,800 aMW of power and/or financial benefits for the FY 2002-2006 period. At least 1,000 aMW would be met with actual BPA power deliveries. The remainder could be provided through either a financial arrangement or additional power deliveries, depending on which approach was most cost-effective for BPA. The IOUs' settlement of rights to request REP benefits under section 5(c) of the Northwest Power Act would be in effect until the end of the contract term. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997).

Under the 10-year settlement contract, in addition to the benefits provided during the first five years, BPA proposed to offer and guarantee 2,200 aMW of power or financial benefits for the FY2007-2011 period. BPA intended for this 2,200 aMW to be comprised solely of power deliveries. The IOUs' settlement of rights to request REP benefits under section 5(c) would be in effect until the end of the 10-year term of the contract. In the event of reduction of Federal system capability and/or the recall of power to serve its public preference customers during the terms of the five-year and 10-year contracts, BPA would either provide monetary compensation or purchase power to guarantee power deliveries.

In summary, residential and small farm loads of the IOUs could receive benefits from the Federal system through one of two ways. An IOU could participate in the established

REP or it could participate in a settlement of the REP through Subscription. If an IOU chose to request REP benefits under section 5(c), then the Subscription settlement amount for all the IOUs would be reduced by the amount that would have gone to the exchanging utility.

D. Power Subscription Strategy Supplemental ROD

As noted above, on December 21, 1998, the BPA Administrator issued a Power Subscription Strategy and accompanying ROD, which set the agency's PBL on a course to establish power rates and offer power sales contracts in anticipation of the expiration of current contracts and rates on September 30, 2001. The Strategy and ROD were the culmination of many public processes that came together to form the framework to equitably distribute in the Pacific Northwest the electric power generated by the FCRPS.

BPA's 1998 Power Subscription Strategy served to guide BPA in accomplishing its goals. After adoption of the Strategy, however, developments occurred that prompted BPA to seek, in some instances, additional comment from customers and constituents on new issues. The Strategy contemplated further public processes to implement its goals. BPA's 2002 power rate case, ongoing since August 1999, was completed on May 8, 2000. BPA and its customers continued discussions on power products and power sales contract prototypes, and the Slice of System product was further defined. In a December 2, 1999, letter, BPA sought comment from customers and constituents on some of these new issues, specifically, the length of the Subscription window for power sales contract offers, the actions required of new small utilities during this window to qualify for firm power service, and new developments with respect to General Transfer Agreements. Other issues arose independently, such as new large single loads (NLSL) under the Northwest Power Act, duration of the new power sales contracts, and a new contract clause regarding corporate citizenship. BPA also undertook a comment process on the amount and allocation of power and financial benefits to provide the IOUs on behalf of their residential and small farm consumers. On November 17, 1999, BPA sent a letter to all interested parties requesting comments on two specific issues: (1) whether the amount of the proposed IOU settlement should be increased by 100 aMW from 1800 aMW to 1900 aMW for the FY 2002-2006 period; and (2) the manner in which the settlement amount should be allocated among the individual IOUs.

1. Total Amount of IOU Settlement Benefits

BPA's intent in the Power Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region. The Subscription Strategy enabled the benefits of the FCRPS to flow throughout the region, whether currently served by publicly owned or privately owned utilities.

The Power Subscription Strategy provided that residential and small farm loads of the IOUs, through settlement of the REP, would be provided access to the equivalent of 1800 aMW of Federal power for the FY 2002-2006 period. At least 1000 aMW of the 1800 aMW would be served with actual BPA power deliveries. The remainder would be provided through either a financial arrangement or additional power deliveries depending on which approach was most cost-effective for BPA.

The four Pacific Northwest state utility commissions (Commissions), in a letter dated July 23, 1999, requested that BPA increase the amount of the settlement from 1800 aMW to 1900 aMW for the FY 2002-2006 period. This request was made in order for the Commissions to arrive at a joint recommendation for allocating the settlement benefits among the IOUs for both the FY 2002-2006 and FY 2007-2011 periods. Many parties supported this increase for many reasons, including: (1) the increase is a wise policy decision and it helps to ensure that the regional interest in the system and preserving the system as a valuable benefit in the Northwest will be shared as broadly as possible among the region's voters; (2) the increase is appropriate in order for BPA to achieve the stated Subscription Strategy goal to "spread the benefits of the Federal Columbia River Power System as broadly as possible, with special attention given to the residential and rural customers of the region," *see* Power Subscription Strategy at 5; (3) the increase creates a fair and reasonable settlement to the REP for the IOUs; (4) the increase to the settlement staves off contentious issues surrounding the traditional REP as well as provides a fair allocation of power to the IOUs; and (5) the increase will help ensure an appropriate sharing of benefits of Federal power among the residential ratepayers in the Northwest.

After review of the comments, BPA found the arguments for increasing the IOU settlement amount by 100 aMW to be compelling. BPA determined that the conditions surrounding the proposed increase to the proposed Subscription settlement of the REP were expected to be met. Therefore, BPA increased the amount of total benefits for the proposed settlements of the REP with regional IOUs from 1800 aMW to 1900 aMW.

2. Allocation of Settlement Benefits Among IOUs

In the Power Subscription Strategy, BPA noted its intent to request comments from interested parties regarding the amounts of Subscription settlement benefits that should be provided to individual IOUs. BPA also noted that the Commissions indicated that they would collaborate on an allocation recommendation. After review of all comments, BPA would determine the appropriate amounts to be allocated to the individual IOUs.

BPA solicited the Commissions' views on the proposed allocation of settlement benefits. This was appropriate because the Commissions have traditionally been responsible for establishing retail electric rates for residential consumers of the regional IOUs, including the credit applied to those rates to reflect benefits of the REP as determined by BPA. The Commissions also have a statutory responsibility to the residential consumers of the IOUs in their particular state jurisdiction. Furthermore, because of these responsibilities, a joint recommendation by the Commissions would likely reflect a fair allocation of benefits among the residential consumers of the Northwest states and would enhance the likelihood of BPA delivering the benefits in a way that would work for each state and its consumers.

The Commissions collaborated and submitted a joint recommendation on the proposed allocation of the settlement benefits. They noted that their recommendation reflects many different considerations, including the amount of residential and small farm load eligible for the REP, the historical provision of REP benefits, the REP benefits received in the last five-year period ending June 30, 2001, rate impacts on qualifying customers, and the individual needs and objectives of each state. BPA reviewed the Commissions' recommendation and determined that this proposal was a reasonable approach upon which to take public comment.

Virtually all commenters supported the allocation recommended by the Commissions and proposed by BPA. The reasons for such support included: (1) it is appropriate for BPA to weigh heavily the Commissions' joint recommendation concerning the allocation of benefits; (2) the Commissions are the best arbiters of the settlement among the IOUs; and (3) the proposed allocation establishes access to a level of benefits that recognizes changed market conditions while at the same time addresses the needs and issues important to each of the four states. It is worthy of note that BPA's allocation has received support from diverse customer and interest groups: publicly owned utilities, IOUs, the Commissions, state agencies, and a city commission. BPA concluded that the following allocation amounts would be incorporated into the proposed settlement contracts with the individual IOUs that choose to settle the REP:

	Amount of Settlement (aMW) FY2002-2006	**Amount of Settlement (aMW) FY2007-2011**
Avista Corp. 1/	90	149
Idaho Power Company 1/	120	225
Montana Power Company	24	28
PacifiCorp (Total)	476	590
PacifiCorp (UP&L)	*140*	*140*
PacifiCorp (PP&L – WA) 1/	*83*	*109*
PacifiCorp (UP&L – OR) 1/	*253*	*341*
Portland General Electric	490	560
Puget Sound Energy (PSE)	700	648
Total	1900	2200

1/ BPA also concluded that the allocation of benefits among the states served by these multi-state utilities would be based on the forecasts of the respective state residential and small farm loads at the time the IOU signs its Settlement Agreement.

E. BPA's Section 5(b)/9(c) Policy

As BPA recognized that its existing long-term power sales contracts would soon expire, BPA proposed to establish a policy to guide the agency in making determinations of the net requirements of its utility customers in order to offer Federal power under new contracts. (For the most part, existing power sales contracts expire by October 1, 2001.) A net requirements policy is an important component to BPA's execution and implementation of new power sales contracts. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a contract to each requesting public body, cooperative, and investor-owned utility to meet each utility's regional firm load net of the resources used by the utility to serve its firm power consumer load. 16 U.S.C. § 839c(b)(1) (1994 & Supp. III 1997). In making this determination, BPA has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), and section 3(d) of the Regional Preference Act, 16 U.S.C. § 837b(d) (1994 & Supp. III 1997).

BPA provided two opportunities for public review and comment in developing its proposed policy. On May 6, 1999, BPA published its initial policy proposal, entitled "Opportunity for Public Comment Regarding Bonneville Power Administration's Subscription Power Sales to Customers and Customer's Sale of Firm Resources," 64 Fed. Reg. 24,376 (1999). BPA held two public meetings to discuss this policy. The first meeting was held on May 27, 1999, in Spokane, Washington. The second meeting was held on June 2, 1999, in Portland, Oregon. On June 3, 1999, the thirty-day comment period was extended by BPA through June 30, 1999.

After reviewing and considering the comments received on the initial policy proposal, particularly those that requested that BPA provide a second round of review and comment, BPA issued a revised policy proposal on October 28, 1999, entitled "Revised Draft Policy Proposal Regarding Subscription Power Sales to Customers and Customer's Sales of Firm Resources," 64 Fed. Reg. 58,039 (1999). BPA reviewed and considered the comments received on the revised policy. On May 24, 2000, BPA issued its final "Policy on Determining Net Requirements of Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act," also called BPA's "Section 5(b)/9(c) Policy." BPA also issued a Section 5(b)/9(c) Policy Record of Decision.

F. IOU Settlement Agreements

After completion of the Administrator's Supplemental ROD, BPA began the development of a prototype Residential Purchase and Sale Agreement (RPSA) and a prototype Settlement Agreement. On May 5, 2000, BPA sent a letter to all interested parties requesting comments on the proposed agreements. BPA's letter included a background document describing the two agreements. BPA also enclosed copies of the draft RPSA and Settlement Agreement. BPA's letter and attachment noted that BPA's Power Subscription Strategy proposed comprehensive settlements of the REP with participating regional IOUs and that IOUs would also have the option of entering into contracts to participate in the REP. The Power Subscription Strategy also noted that public agency customers were eligible to enter RPSAs under the REP.

BPA's letter noted that BPA had prepared a prototype RPSA to implement the REP and that this prototype would be used as the basis for contracting with all eligible parties to apply for benefits under the REP. BPA requested public comment on the following issues: (1) which entities are eligible utilities to request benefits under section 5(c) of the Northwest Power Act; (2) BPA's proposal to implement the in lieu provisions of section 5(c)(5) of the Northwest Power Act through wholesale market purchases; (3) any exceptions to the limitations of section 5(c)(6) that preclude the restriction of exchange sales under section 5(c) below the amounts of power acquired from, or on behalf of, the utility pursuant to section 5(c); and (4) any comments on the terms and conditions of the prototype RPSA agreement.

BPA's letter also described BPA's proposal for comprehensive settlement of the rights of regional IOUs eligible for benefits under the REP. BPA noted that it had prepared a prototype Settlement Agreement for implementing the Subscription Strategy. The prototype provided power sales pursuant to a contract offered under section 5(b) of the Northwest Power Act. The prototype also provided for the payment of monetary benefits. BPA requested public comment on all relevant issues, including the following issues: (1) any comments on the terms and conditions of the prototype Settlement Agreement; and (2) whether the total amount of benefits and the proposed terms and conditions for settling the rights of regional IOUs to request benefits under the REP were reasonable.

BPA's letter noted that BPA's Power Subscription Strategy proposed an allocation of benefits to the region's IOUs that included both physical and monetary components. It further noted that the Administrator's Supplemental ROD for the Power Subscription Strategy proposed to offer the IOUs the equivalent of 1900 aMW of Federal power for the FY 2002-2006 period. Of this amount, at least 1000 aMW would be provided in physical power deliveries. BPA requested that each IOU notify BPA by July 21, 2000, whether they wished to participate in BPA's REP. The IOUs were not required to make an election whether to accept a settlement offer or participate in the REP through an RPSA at that time. Based on each IOU's request to participate in the REP, BPA would prepare a settlement offer for their consideration prior to October 1, 2000. At the time each IOU requested to participate in the REP in July, BPA's letter asked that each IOU identify (1) its preferred mix of physical deliveries and financial settlement; and (2) whether it would prefer a five-year or 10-year offer. BPA would only make a settlement offer including net requirements physical deliveries if the IOU could establish a net requirement for the amount of power requested.

BPA's letter requested public comment on two issues regarding the offer of physical power and financial benefits in settlement of REP rights: (1) whether BPA should require IOUs to take additional power if the combined requests of all the companies for physical deliveries are less than 1000 aMW; and (2) how BPA should limit physical deliveries to each IOU if the companies requested physical deliveries of more than 1000 aMW and such deliveries were more power than BPA was willing to offer.

Comments on all of the issues regarding the prototype agreements were to be submitted through close of business on Friday, June 9, 2000. BPA's letter noted that after receiving public comment on the proposed prototype agreements, BPA would prepare final draft prototypes based on the public comments. These draft prototypes will be published to allow IOUs to determine whether they wish to participate in the REP pursuant to an RPSA or through a settlement offer based on physical or monetary benefits. Once BPA received each IOU's request to participate in the REP, BPA would prepare a settlement offer and an RPSA for each IOU in accordance with the choices made. BPA prepared a ROD addressing the public comments on the proposed REP Settlement Agreements. A separate ROD was also issued which addressed the public comments on the proposed RPSA. BPA offered both an RPSA and a Settlement Agreement to each IOU. .

On July 28, 2000, BPA sent a letter to interested parties regarding a request by Montana Power Company (MPC) to be offered a Settlement Agreement in which the power component would be made under section 5(c) of the Northwest Power Act instead of a sale of requirements power under section 5(b) of the Act. BPA's letter noted that on May 5, 2000, BPA asked for public comment on BPA's proposed contracts for implementing the REP, including a request for comments on a proposed IOU Settlement Agreement. The Settlement Agreement BPA offered for comment on May 5 contained benefits that were comprised of proposed power sales and monetary payments. The power sales proposed under the Settlement Agreement were sales under section 5(b) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997). However, as BPA stated in its Power Subscription Strategy, released on December 21, 1998, power sales in its proposal for settling the REP could be based either under section 5(b) or 5(c) of the Northwest Power Act. In the background document included with BPA's May 5 letter, BPA noted that it had not prepared a prototype Settlement Agreement based on a power sale under section 5(c) of the Northwest Power Act, but that it would consider such proposals if they were made.

In a letter dated July 27, 2000, MPC requested that BPA provide a settlement offer including firm power benefits under section 5(c) of the Northwest Power Act. BPA prepared a draft Settlement Agreement reflecting a section 5(c) power sale. The proposed settlement, attached to BPA's July 28, 2000, letter, was very similar to the proposed agreement that BPA issued for public comment with BPA's May 5, 2000, letter. Instead of providing an IOU Firm Power Block Sales Agreement (Block Sales Agreement) for a specified amount of firm power under section 5(b) of the Northwest Power Act, this proposed section 5(c) prototype agreement provided a specified amount of firm power under a Negotiated In Lieu Agreement.

On October 4, 2000, the BPA Administrator issued a decision document entitled "Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision," which concluded that it was appropriate to offer the REP Settlement Agreements to regional IOUs. The REP

Settlement Agreements were then executed the same month. One of the regional IOUs executing a settlement agreement was PacifiCorp.

G. BPA's 2002 Wholesale Power Rate Case

On August 13, 1999, BPA published a notice of BPA's *2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment.* 64 Fed. Reg. 44,318 (1999). This began a lengthy and complex hearing process that concluded with BPA's *2002 Final Power Rate Proposal, Administrator's Record of Decision*, in May 2000 (May Proposal). 16 U.S.C. § 839e(i). In July 2000, BPA filed its proposed 2002 wholesale power rates with the Federal Energy Regulatory Commission (FERC) for confirmation and approval. 16 U.S.C. § 839e(a)(2). Subsequent to that time, however, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before. By August, it was clear that these market prices were not a short-term phenomenon. This meant that BPA's cost-based rates, which were already below the original market forecast, were even more attractive. Thus, BPA assumed that additional load would be placed on BPA, and BPA would need to purchase additional power to augment the Federal Columbia River Power System (FCRPS) supply. BPA determined that the implications for cost recovery were so serious that a stay of the rate proceeding at FERC was requested. This enabled BPA to review the events that had occurred during the summer months and to determine whether the escalating prices and increased volatility would require remedial action.

Escalating and more volatile market prices had two related effects. First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. Second, to meet this increased load obligation, BPA would need to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. BPA concluded that the May Proposal, as filed with the FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA.

During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources by 1,732 average megawatts (aMW). Due to escalating and volatile market prices, BPA estimated that expected loads would exceed the original rate case forecast by an additional 1,518 aMW. Inasmuch as the generating capability of FCRPS was already inadequate to meet the earlier load forecast, BPA would have to purchase to further augment its inventory to serve these additional loads. The cost of power to serve these unanticipated loads was not included in revenue requirements.

The combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminished the probability that rates proposed in the May Proposal would fully recover generation function costs. Absent a change to the May Proposal, Treasury Payment Probability (TPP) would be reduced to below 70 percent, a level that would fall well short of specific goals and targets. In its judgment, BPA had a serious cost recovery problem that it was obliged to address by reason of statute and Administration policy.

BPA's Amended Proposal rate case was a continuation of the WP-02 rate proceeding. It was being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. During the consideration of the Amended Proposal, however, BPA concluded that it was necessary to make additional changes to ensure BPA's cost recovery. BPA then filed a Supplemental Proposal. There were three reasons BPA filed a Supplemental Proposal. First, BPA's forecast for starting rate period reserves had dropped very substantially since the forecast in its Amended Proposal. Second, market prices available for power during the first two years of the rate period were significantly higher than BPA had forecast in the Amended Proposal. Regardless, BPA would have prepared an update to the Amended Proposal to show the impact of these revised forecasts on BPA's proposed rates. The third reason was that, as a result of discussions with the rate case parties, BPA reached a Partial Settlement Agreement with many of those parties. Part of that agreement was that BPA would file a Supplemental Proposal reflecting the Partial Settlement Agreement.

Since BPA filed its Amended Proposal in December 2000, forecasts for run-off for the water year had declined substantially. Water Year forecasts in BPA's 2002 Final Power Rate Proposal (May Proposal) and Amended Proposal assumed average water for both this FY 2001 and for the next five years of the rate period – 102.4 million acre feet (MAF). By contrast, the current year could be the second lowest runoff year on record, with current runoff forecasted at under 60 MAF. These conditions would require BPA to purchase much more power this year than expected to meet loads, at extremely high prices, and to reduce the amount of surplus energy BPA can sell this year. As BPA described in its Amended Proposal, prices in the wholesale electricity market had been extremely volatile and high. BPA had seen these increased market prices during this year. In fact, during one week in January alone, BPA purchased over $50 million in power to meet load. This was putting tremendous pressure on BPA's end-of-year reserves. End-of-year reserves translate into starting rate period reserves. In BPA's May Proposal, starting reserves were estimated to be $842 million on an expected value basis. In BPA's Amended Proposal, starting reserves expected value estimates had increased to $929 million. Then, the expected value of BPA's starting reserves estimate dropped to $309 million. There is still a significant range of uncertainty surrounding this estimation of starting reserves. This is driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices.

Starting reserves are a key risk mitigation tool in BPA's Supplemental Proposal. A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools need to be made.

Market prices during the rate period are higher in the first years of the rate period, ranging from $200/megawatthour (MWh) to $240/MWh for FY 2002, and then dropping during the last years of the rate period, to a range between $40/MWh and $60/MWh in FY 2006. This compares with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around $48/MWh, where expected prices for individual years did not vary by more than $5/MWh from the $48/MWh average.

Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market. Therefore, BPA revised the LB CRAC so that its expected revenues closely match the shape of its augmentation costs. In summary, BPA's Supplemental Proposal suggested that BPA's customers could see much higher prices during the October 1, 2001, to September 30, 2006, rate period.

H. Administrator's Call for Rate Mitigation Efforts

On April 9, 2001, the BPA Administrator delivered a speech to the citizens of the Pacific Northwest regarding the potential impact of BPA's proposed rate increase and possible ways to reduce the impact of the increase. The text of the speech follows:

> Last January, I sent out a letter to Northwest citizens that caused some shock waves. That was my intent. I believe it is important to warn of bad news while there is still time to take actions that can lessen the impact. At the time, I said that, if certain conditions persisted, BPA's customers--Pacific Northwest utilities and direct-service industries--could face a significant rate increase for the wholesale power they buy from the Bonneville Power Administration. The figures I cited then were for an average rate increase of 60 percent over the five-year rate period that starts this coming October. I cautioned that the increase could be as high as 90 percent in the first year.
>
> Unfortunately, the situation has worsened. It now appears possible that, without the kinds of action that I am about to call for today, the first-year increase could be 250 percent or more. If that were to occur, it likely would translate into doubling the retail rates in many utility service areas.
>
> An increase of this magnitude would have widespread economic consequences. Already, we are seeing some businesses curtail operations or even close as a result of high energy prices. With such an increase, we'd surely see more businesses close and more job losses, with people

with lower incomes suffering disproportionately. In addition, a weak economy frequently translates into less public support for environmental protection.

I don't believe these consequences are acceptable. More importantly, I don't believe they are inevitable. That's why I am here today to call for some very specific actions and to call on all stakeholders in the Pacific Northwest to own part of the process that will help us avert an economic blow to our region. I believe we can get the rate increase down to a manageable level, but we need to make some tough decisions, and we have little more than 60 days to do this. BPA's rates, which will go into effect in October, should be submitted to the Federal Energy Regulatory Commission in June.

First, let me review what has led us to this point. Some of it you already know. We are experiencing the second worst water year in 72 years of record-keeping. According to a report released by the Northwest Power Planning Council, if the drought persists, the hydropower generating capability in the Northwest from March through August will be 4,700 megawatts below normal over those months--the equivalent power consumed by four Seattles. The implications are ominous since the Northwest relies on hydropower for nearly three-quarters of its electricity.

But the summer drought is only the immediate crisis. We are becoming increasingly concerned about power supply for the coming winter. Canadian reservoirs, which store half the system's water, are extremely low this year, which means we could start next year with less than a full tank. If that were to happen, and especially if we have a second dry year in a row, electricity reliability wouldn't be the only thing at risk. Low reservoir levels also raise concerns for salmon and steelhead next year.

Low water combined with a tight wholesale power market and skyrocketing power prices is a devastating combination. The fiasco in California has helped drive wholesale electricity prices to unprecedented levels. When we completed our new Subscription power contracts last fall, BPA's contractual obligations added up to approximately 11,000 megawatts--about 3,000 megawatts more than our current generating resources can provide on a firm basis. The only way we can meet our obligations is to buy the vast majority of the additional power in a wholesale power market where supplies are tight and prices are sky high. This is what is driving rates up.

This year, due to the high power prices, BPA has not been able to purchase sufficient power to ensure system reliability. Consequently, we have periodically declared power system emergencies. These emergency declarations have allowed us to increase power generation from the river and reduce operations that offer benefits to migrating juvenile fish. The increased generation has reduced the amount of water that is normally stored at this time of year so that it can be used to augment spring and summer river flows. While there may be some impact on fish, by far the major impact on fish is the drought itself, not the emergency power operations. We are continuing to implement all other aspects of the federal measures for fish recovery.

Currently, we are operating the river on an emergency basis, and we can continue some fish spill or flow augmentation only as long as water volume does not dip much below current estimates. The record low runoff is a water volume of 53 million-acre feet. As of last week, the volume forecasts had dropped to 56 million-acre feet, which is 53 percent of the normal runoff. This severely limits our flexibility to do much more than meet power needs.

Beyond the current drought, high power prices are expected to continue until significant new generation and additional conservation measures are put in place. This will take a couple of years at best. And, we can't expect much help from Canada, which also is suffering drought, nor any help from California, which is in the throes of an electricity restructuring crisis.

We must focus instead on what we can control if we expect to minimize the size of the coming wholesale rate increase. The most immediate and direct way to decrease the size of next year's rate increase is quite simply to decrease the amount of power BPA has to buy in the market.

We already have taken a number of extraordinary steps in this direction. We have promoted conservation aggressively and sought voluntary curtailments in power use. We have begun to purchase curtailments from our direct service industrial customers and from irrigators who are served by our utility customers. We have offered innovative incentives for development of conservation and renewables, and we have engaged in beneficial 2-for-1 power exchanges with California. We also are continuing to collaborate with the Corps of Engineers and Bureau of Reclamation to increase the productive capability of the federal power system.

But even these extraordinary measures haven't been enough in the face of the triple whammy of historic low water conditions, an extremely tight power market and enormous volatility in power prices. We now need to up the ante if we are to get the rate increase for the next year down to a manageable level.

We literally are at a crossroads, and the region has essentially two options. Path A is to wait and see where market prices settle in June. Under this scenario, we'd rely on cost recovery mechanisms to kick up rates if prices remain high. We would take no special actions and we wouldn't push or negotiate with our customer groups to secure load reductions. The risk is that, if market prices stay the same, we could expect to see a first year rate increase in the 200 to 300 percent range, and possibly greater.

Then there's Path B, which calls for aggressive and immediate steps to reduce the size of the rate increase by reducing the amount of electricity demand put on BPA. Under this scenario, BPA would not have to buy as large an amount of power in a very expensive wholesale power market. It's a strategy that calls on our customers and other stakeholders to share a sacrifice by reducing their demands for power. It requires significant, and I mean significant, contributions from all customer groups. It could keep the first-year rate increase below 100 percent. I believe Path B is the course we must choose, so let me lay out some of the actions that will move us along this path.

As I discuss this path, let me outline the principles I believe are key to reducing rates. First, rates must be set to cover costs if we are to avoid creating a credit problem, which could lead to refusals to sell to us in the future. We must also cover our costs to ensure we preserve the benefits of the federal hydropower system over the long term, which is essentially the bottom line.

Second, the situation is urgent. We must act quickly because rates must be in effect this coming October 1. As I said earlier, our rate proposal is due in to the Federal Energy Regulatory Commission in June.

Third, our problem is caused by a significant exposure to a volatile market in the first one-to-two years of the rate period. If we are to manage a reduction in the rate increase, we must reduce our exposure to that market by reducing demand for energy, increasing our supply and minimizing the short and long-term damage to the region's economy.

Fourth, contributions to the solution are needed from all customers. We can't play a game a chicken where each party waits for the other to step forward. If that happens, no one will step forward. Each group must contribute if we are to preserve an equitable distribution of the benefits of our hydropower resource.

. . .

Given those principles, let me outline the actions we as a region need to take. We need a three-pronged approach that includes curtailment of power use, conservation--or more efficient use of power--and power buybacks. This needs to happen across all four states, across public and private power, and across all sectors of energy use--industrial, commercial, agricultural and residential. It will take all of us working together if we are to avoid severe economic hardships for the region. Let me be clear; what I am about to suggest requires a great deal of sacrifice, but the alternative is to suffer far more serious consequences. We are beginning negotiations now with our customers. If people don't come to the table with reductions in their demand for electricity, a very large and very damaging rate increase is inevitable.

First, we are calling on our public utility customers to make a contribution to the solution. We need every utility customer to reduce its Subscription purchases from BPA by 5 to 10 percent. BPA's rate increases will spur some of this reduction, but more focused efforts are needed if we are going to achieve significant savings. We are willing to make modest incentive payments to help achieve this, but the incentive payments cannot be large or they will defeat the intended effect.

We are running several demand-side management initiatives including a conservation and renewables discount, a conservation augmentation program and a demand exchange program. In addition, we now are discussing the potential for new programs to provide incentives to our public utility customers to adopt innovative retail rate structures that encourage their consumers to conserve energy.

Second, we are calling on investor-owned utilities to make a contribution. When our new rates go into effect this October, investor-owned utilities--or IOUs--will receive sizable benefits from BPA for their residential and small farm customers as a result of a the residential exchange. Under this program, as it is set out in the Subscription period, 1,900 average megawatts of financial and power benefits are scheduled to go to the IOUs. But, because of dramatic changes in market prices, the estimated value of these benefits has increased enormously since they were negotiated a year ago. By 2002, the value will be 10 times higher than the negotiations intended to capture. As a result, IOUs are in a position to reduce their Subscription demand significantly and still enjoy benefits in excess of anything they have experienced in the 20-year history of the residential exchange.

Third, we are asking our direct service industries--or DSIs--to agree not to take power from us for up to the first two years of the rate period in return for certain limited compensation to the companies and their workers. It is our expectation that the companies would not be able to operate given a potential tripling of our rates anyway. Coming to an agreement now that the plants will not operate would allow BPA to avoid making power purchases, thereby decreasing our rates for all remaining customers.

It is not our intention to drive the aluminum industry out of the region, but we are continuing to encourage the industry to move off of BPA power supplies after the 2006 rate period because we do not have a statutory obligation to continue to serve them. The customers we are obligated to serve--the region's retail electric utilities--need more than our current generation resources can produce. We will work with these companies to help them find a means to operate profitably in the long run without relying on BPA.

Almost all of the DSIs are already shut down until this fall, and their power is being remarketed to support Northwest needs during the current drought. These buydowns played a key role in keeping the lights on this winter and in maintaining reservoir levels higher than they otherwise would have been.

Fourth, I am urging all citizens of the Northwest to heed the call of our governors to reduce electricity consumption by 10 percent through eliminating waste and using electricity more efficiently. There are a number of common sense measures we can all take, and one good place to start right now is to go out and replace conventional light bulbs with compact fluorescents, which consume about 20 percent of the electricity used by regular bulbs for the same amount of light.

These four sets of actions that I have described are urgently needed between now and June if we are to avert grave near-term economic consequences. These are difficult actions. But, with hindsight, we can learn from the problems California experienced and seek to avoid them. We need to do everything we can to avoid power purchases in this incredibly expensive market. We also need to make sure we set rates high enough so we can cover our costs to assure generators get paid when they deliver power on a contractual basis so we don't put our credit at risk.

We also are looking to longer-term solutions that will help lead to lowering the incredible wholesale power supply prices we are currently experiencing. The fundamental problem is supply and demand being out of balance. Prompt infrastructure investments are needed in generating resources, especially gas-fired and wind-powered generation; gas pipeline capacity and storage; electric power transmission facilities; and energy conservation measures.

BPA's [proposed] rates [might] now be set on a six-month basis based on our actual costs. If wholesale power prices can be brought down quickly, through infrastructure investments and other actions, then our rates will come down in the future. The faster these actions can be taken, the quicker our rates can come down.

We already have begun plans to shore up the transmission infrastructure, and we are negotiating to purchase the output from combustion turbines and new renewable resources. We also are increasing our efforts to encourage and procure energy efficiency. We are working to implement these actions quickly, but at best, some actions, such as securing more generation, will take one-to-two years.

That's why I am calling for cooperation and sacrifices for the next two years from all parties BPA serves. If the region cannot or will not take the actions necessary to reduce the rate hike, we have no recourse but to set our rates to recover our costs. BPA does not receive subsidies from taxpayers. We must wholly cover our costs with revenues we receive from sales of power and transmission. We are obligated to repay, with interest, all capital investments that have been made by the federal government in the facilities that are part of the Northwest's federal power system. Already, we have drawn on our financial reserves heavily this winter, and more of the same still may be ahead of us.

Some have suggested that we can simply fail to pay one of our largest creditors--the U.S. Treasury--rather than declare power emergencies or raise rates sharply. While there is no absolute guarantee we will make our full Treasury payment this October, I believe we should use all management tools available to do so. Our ability to pay our debt in full and on time is the best protection the Northwest has to preserve the benefits of the Columbia River hydropower system for the region. There are interests outside the region that want to see the benefits of this system directed toward other purposes. They could take great political advantage of the opportunity that would be presented if BPA did not cover its costs. One consequence could be the loss of cost-based rates for power from the federal system. We have seen how exorbitant market rates can be. If that were to happen, the region would be looking at far higher rate increases than we are now facing.

So, in closing, let me underscore the message. We are on a trajectory that poses grave consequences for the Pacific Northwest, primarily due to extraordinary conditions beyond our control--extremely low water, an extremely tight power supply and extremely high wholesale power prices. We believe the only alternative to a huge rate hike is to reduce our exposure to the market in the first two years of the next five-year rate period by reducing the Subscription demand on BPA. It will take major contributions from all our customers if we are to prevent a triple digit rate increase. And, we will need to make these very difficult decisions very quickly.

> Finally, we believe this proposal, while not an easy one to achieve, fairly balances the sacrifices the region needs and does not unfairly hit one customer group or one state over others. I know putting these proposals into place will be tough, but I believe the consequences of not taking this path will even be tougher.

Thus, the Administrator asked the regional IOUs to contribute to the mitigation of BPA's potentially difficult rate increases. The Administrator's reasoning regarding the amendment to PacifiCorp's REP Settlement Agreement and the separate Financial Settlement Agreement, which help to address this concern, is addressed below.

I. AMENDMENT TO PACIFICORP'S REP SETTLEMENT AGREEMENT

BPA and PacifiCorp have negotiated a letter agreement (Amendment No. 1), which constitutes an amendment to PacifiCorp's Residential Exchange Program Settlement Agreement, Contract No. 01PB-12229 (Settlement Agreement), executed by BPA and PacifiCorp. Since the time of execution of the Parties' Settlement Agreement, BPA and PacifiCorp have agreed that BPA will, rather than deliver firm power to PacifiCorp for the first five years of the Settlement Agreement, make cash payments during the period that begins October 1, 2001, and ends on September 30, 2006. These cash payments will be made under a Financial Settlement Agreement, Contract No. 01PB-10854. Amendment No. 1 removes BPA's obligation to deliver firm power for the first five years of the Settlement Agreement. BPA and PacifiCorp intend to execute Amendment No. 1 and the Financial Settlement Agreement simultaneously.

A number of issues arose during the negotiation of Amendment No. 1 and the Financial Settlement Agreement. The reasoning supporting the resolution of these issues is addressed below.

A. EFFECTIVE DATE

Section 1 of Amendment No. 1 provides that it will take effect on the date signed by the Parties. This allows the amendment to take effect at the beginning of the contract period.

B. AMENDMENT OF SETTLEMENT AGREEMENT

1. Satisfaction of Section 5(c) Obligations

Section 2 of Amendment No. 1 describes a number of changes to the Settlement Agreement. Section 3(a) of the Settlement Agreement is replaced by language providing that BPA, in full and complete satisfaction of its obligations under or arising out of section 5(c) of the Northwest Power Act during the period from July 1, 2001, through September 30, 2011,will provide PacifiCorp three things. First, BPA will provide cash payments for the period from July 1, 2001, through September 30, 2001, pursuant to section 3(d) of the Settlement Agreement. Second, BPA will provide, beginning October 1, 2001, and continuing through September 30, 2006, cash payments under the Financial Settlement Agreement in lieu of firm power deliveries under the Settlement Agreement, plus Monetary Benefit payments under the Settlement Agreement. Third, BPA will provide, beginning October 1, 2006, firm power or Monetary Benefit payments, or both, pursuant to sections 4 and 5 of the Settlement Agreement. Similarly, PacifiCorp agrees that the cash payments, Firm Power or Monetary Benefits, or both, provided under the Settlement Agreement, and the cash payments provided under the Financial Settlement Agreement, satisfy BPA's obligations under section 5(c) of the Northwest Power Act during the period from July 1, 2001, through September 30, 2011. This provision incorporates the substitution of benefits under the Financial Settlement Agreement for the reduction of firm power deliveries under the Settlement Agreement into the satisfaction of BPA's section 5(c) obligation to PacifiCorp.

2. Invalidity

(a) Invalidity of the Settlement Agreement

The Parties have worked diligently to ensure that Amendment No. 1 and the Settlement Agreement are legally sound and will be effective for their respective terms. Some BPA customers, however, have been extremely litigious regarding the implementation of BPA's Power Subscription Strategy. Given this environment, an invalidity provision addresses the possibility, hopefully slight, that a challenge might render the agreements invalid. Section 3(b) of the Settlement Agreement is replaced by new language. This language provides that if the United States Court of Appeals for the Ninth Circuit finally determines that the Settlement Agreement (or payments under section 4 of the Settlement Agreement) is invalid, then PacifiCorp has two options. First, PacifiCorp can provide written notice to BPA within 30 calendar days that the cash payments provided under the Financial Settlement Agreement satisfy all of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act for the period following the court's final determination through September 30, 2006. Second, if PacifiCorp provides no notice, BPA and PacifiCorp agree that the provisions of section 3(a), which establish the satisfaction of BPA's section 5(c) obligations, will be of no further force or effect.

A new section 3(b)(1) of the Settlement Agreement also provides that in the event of the court's above-noted final determination, the Parties intend that the cash payments pursuant to section 3(d) and the Monetary Benefits provided prior to the court's final determination should be retained by PacifiCorp, to the maximum extent permitted by law. Also, the satisfaction of BPA's obligations to PacifiCorp under section 5(c) of the Northwest Power Act prior to the court's final determination should be preserved, to the maximum extent permitted by law. This would avoid a difficult and complicated process of determining a new agreement and retroactively implementing changes to the benefits for that period. Additional difficulties would lie in the ability of PacifiCorp and the state public utility commissions to implement such changes without creating potential economic harm to consumers. In addition, section 3(b)(1) provides that it is severable and would continue in effect in the event that any other provision of the Agreement was found invalid.

(b) Invalidity of the Financial Settlement Agreement

A new section 3(b)(2) of the Settlement Agreement provides that in the event the United States Court of Appeals for the Ninth Circuit finally determines, after all appeals or requests for reconsideration, that the Financial Settlement Agreement (or cash payments under the Financial Settlement Agreement) is invalid, then PacifiCorp has two options. First, PacifiCorp can provide written notice to BPA within 30 calendar days that the Monetary Benefits provided under section 4 of the Settlement Agreement satisfy all of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act for the period following the court's final determination through September 30, 2006. Second, if PacifiCorp provides no notice, BPA and PacifiCorp agree that the provisions of section 3(a), which establish the satisfaction of BPA's section 5(c) obligations, will be of no further force or effect. Section 3(b)(2) also provides that in the event of the court's above-noted final determination, the Parties intend that the cash payments pursuant the Financial Settlement Agreement and the Monetary Benefits provided under the Settlement Agreement provided prior to such final determination will be retained by PacifiCorp, to the maximum extent permitted by law. Also, the satisfaction of BPA's obligations to PacifiCorp under section 5(c) of the Northwest Power Act prior to the court's final determination should be preserved, to the maximum extent permitted by law. As noted previously, this would avoid a difficult and complicated process of determining a new agreement and retroactively implementing changes to the benefits for that period. Also, additional difficulties would lie in the ability of PacifiCorp and the state public utility commissions to implement such changes without creating potential economic harm to consumers.

(c) Negotiation of New Agreement if this Agreement Held Invalid

Section 3(c) of the Settlement Agreement is replaced by new language. This language provides that if the Settlement Agreement (or section 4(a), section 4(c), or section 5 of that Agreement) is finally determined to be invalid and PacifiCorp does not notify BPA that the cash payments under Financial Settlement Agreement satisfy all of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act as described in section 3(b)(1), then both Parties agree to negotiate in good faith a new, mutually acceptable agreement that would, until the end of its term, be in satisfaction of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act. The term of the new agreement would continue for the remaining term of the Settlement Agreement.

3. Settlement Benefits

A new section 4(a)(1) of the Settlement Agreement eliminates BPA's obligation to provide firm power to PacifiCorp during the period from October 1, 2001, through September 30, 2006. This section reduces BPA's obligation to purchase 251 annual average MW of firm power in the wholesale market for a period of five years. BPA has substituted an obligation to make cash payments under the Financial Settlement Agreement. Sections 4(b)(1)(A), 4(b)(1)(B), and 4(b)(1)(C), which related to firm power deliveries under the Settlement Agreement from October 1, 2001, through September 30, 2006, were deleted.

Section 4(a) of Exhibit A of the Settlement Agreement (Contract No. 01PB-12230) is amended to eliminate BPA's obligation to make firm power available to PacifiCorp under its Firm Block Power Sales Agreement during the period from October 1, 2001, through September 30, 2006.

4. Termination of Amendment No. 1

Section 3 of Amendment No. 1 provides that if BPA does not adopt the Partial Stipulation and Settlement Agreement in BPA's WP-02 Wholesale Power Rate proceeding, then PacifiCorp may, upon written notice to BPA prior to September 1, 2001, terminate both Amendment No. 1 and the Financial Settlement Agreement. This provision addresses PacifiCorp's concern that BPA's proposed wholesale power rates may not turn out consistent with a settlement agreement that BPA staff and many customers agreed to in BPA's Supplemental Proposal. In such case, PacifiCorp would not be willing to agree to the terms of Amendment No. 1 and the Financial Settlement Agreement.

II. FINANCIAL BENEFITS SETTLEMENT

The Northwest Power Act establishes a Residential Exchange Program to provide benefits to residential and small farm consumers of Pacific Northwest utilities. Also, BPA implements the REP through the offer, when requested, of a Residential Purchase and Sale Agreement. On October 31, 2000, BPA and PacifiCorp entered into Contract No. 01PB-12229 (the "Settlement Agreement"), which provides, among other things, for BPA to provide PacifiCorp with Firm Power and Monetary Benefits to settle the REP. The term of the Settlement Agreement continues through September 30, 2011. Since the execution of the Settlement Agreement, BPA and PacifiCorp have agreed that BPA will, rather than deliver firm power to PacifiCorp for the first 5 years of the Settlement Agreement, make cash payments to PacifiCorp during the period that begins October 1, 2001, and ends on September 30, 2006. The cash payments in lieu of firm power deliveries under the Settlement Agreement will be as provided for under the Financial Settlement Agreement. The Parties will also simultaneously execute an amendment to the Settlement Agreement that removes BPA's obligation to deliver Firm Power during the first 5 years of the Settlement Agreement.

A number of issues arose during the negotiation of the Financial Benefits Agreement. The reasoning supporting the resolution of these issues is addressed below.

A. TERM

As noted previously, the intent of the Agreement is to provide PacifiCorp cash payments in lieu of firm power deliveries under the Settlement Agreement for the first five years of that agreement. Therefore, the Agreement takes effect on the date signed by the Parties. Performance of the Agreement begins on July 1, 2001, and continues through September 30, 2006, unless terminated prior to that date. Even though cash payments under the Agreement do not start until October 1, 2001, the parties recognized that PacifiCorp may start implementation of the passthrough requirements of the Agreement as early as July 1, 2001.

B. DEFINITIONS

The Parties agreed to certain defined terms in order to implement the Agreement. These terms are generally consistent with the defined terms in the Settlement Agreement.

C. SATISFACTION OF SECTION 5(c) OBLIGATIONS

1. Satisfaction of Section 5(c) Obligations

The purpose of the Agreement is to provide PacifiCorp with financial benefits in order to settle PacifiCorp's rights to participate in the REP during the period from October 1, 2001, through September 30, 2006. Part of the financial benefits are provided in lieu of power under the Settlement Agreement, and part of the financial benefits are the Monetary Benefits PacifiCorp receives under the Settlement Agreement. Therefore, the Agreement provides that BPA will provide PacifiCorp: (1) cash payments for that period (as discussed in greater detail below regarding section 4 of the Agreement); and (2) Monetary Benefit payments during that period under the Settlement Agreement, as amended. These payments will comprise full and complete satisfaction of all of BPA's obligations during the above-noted period under or arising out of the REP, which is established in section 5(c) of the Northwest Power Act. PacifiCorp, in turn, agrees that the foregoing payments and benefits provided under the Agreement and the Settlement Agreement satisfy all of BPA's obligations regarding the REP for the noted period.

2. Invalidity

The Parties have worked diligently to ensure that the Settlement Agreement and this Agreement are legally sound and will be effective for their respective terms. Some BPA customers, however, have been extremely litigious regarding the implementation of BPA's Power Subscription Strategy. Given this environment, an invalidity provision addresses the possibility, hopefully slight, that a challenge might render the agreements invalid. Section 3(b)(1) of the Agreement provides that in such an event, PacifiCorp can make an election. First, PacifiCorp can provide written notice to BPA within 30 days that the Monetary Benefits provided under the Settlement Agreement satisfy all of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act during the period following the court's ruling through September 30, 2006. Alternatively, if PacifiCorp provides no notice, BPA and PacifiCorp agree that the provisions of section 3(a), which establish the satisfaction of BPA's section 5(c) obligations, will be of no further force or effect.

Section 3(b)(1) also provides that in the event of the court's above-noted final determination, the Parties intend that the cash payments pursuant to section 4, and the Monetary Benefits provided prior to the court's such final determination, should be retained by PacifiCorp, to the maximum extent permitted by law. Also, the satisfaction of BPA's obligations to PacifiCorp under section 5(c) of the Northwest Power Act prior to the court's final determination should be preserved, to the maximum extent permitted by law. This would avoid a difficult and complicated process of determining a new agreement and retroactively implementing changes to the benefits for that period. Additional difficulties would lie in the ability of PacifiCorp and the state public utility commissions to implement such changes without creating potential economic harm to consumers. In addition, section 3(b)(1) provides that it is severable and would continue in effect in the event that any other provision of the Agreement was found invalid.

Section 3(b)(2) of the Agreement addresses the potential invalidity of the Settlement Agreement. This provision is very similar to section 3(b)(1). In the event the court finally determined that the Settlement Agreement (or the payment of Monetary Benefits under the Settlement Agreement) was void, then PacifiCorp has two options. First, PacifiCorp could provide written notice to BPA within 30 calendar days that the cash payments provided under section 4 of this Agreement satisfy all of BPA's obligations under section 5(c) of the Northwest Power Act during the period following the court's final determination through September 30, 2006. Alternatively, if PacifiCorp provides no notice, BPA and PacifiCorp agree that the provisions of section 3(a) of the Agreement would be of no further force or effect. Section 3(b)(2) also includes the same provisions noted in the preceding paragraph.

Section 3(b)(3) of the Agreement provides that if the Agreement (or payment under section 4 of the Agreement) were finally determined to be unlawful, void, or unenforceable, and PacifiCorp did not notify BPA that the Monetary Benefits provided under the Settlement Agreement satisfy all of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act as described in section 3(b)(1), then both Parties agree to negotiate in good faith a new, mutually acceptable agreement that would, until the end of its term, be in satisfaction of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act. The term of such new agreement would continue for the remaining term of the Agreement.

D. CASH PAYMENTS

BPA has negotiated cash payments to PacifiCorp for two different time periods. During the first year of the Agreement, from October 1, 2001, through September 30, 2002, BPA has negotiated a cash payment based on two different principles. Under the first principle, PacifiCorp has agreed to reduce BPA's obligation to deliver firm power by 10% (or 25 annual aMW) in exchange for a cash payment of $20 per MWh. This payment is substantially below the market value for a one-year purchase of firm power from the wholesale market and represents PacifiCorp's contribution to the regional effort to reduce BPA's wholesale rate increase. This reduced payment is contingent on BPA's other customers contributing to the regional effort as further described below in the section on load reduction contingency. If the contingencies in the load reduction provisions occur, this payment will increase to $38 per MWh.

The balance of the first year payment for the remaining 226 annual aMW of firm power and the payments for the remaining four years for 251 annual aMW is based on a cash payment of either $38 or $45.49 per MWh depending on the results of settlement discussions among PacifiCorp and BPA's public agency customers. This payment reflects the value to BPA of avoiding a purchase of wholesale firm power for a five-year period.

During the one-month period of negotiation of this Agreement, the market price for five-year purchases of firm power has varied between $100 per MWh and $75 per MWh, reflecting the current high and volatile market prices. If BPA had supplied firm power to PacifiCorp, BPA forecasts that the rate paid by PacifiCorp would average between $28-$38 per MWh depending on market prices and assumptions made about BPA's success in reducing its wholesale rates through the current regional effort. BPA believes that the payment to PacifiCorp is a reasonable payment by BPA to avoid a purchase in the wholesale market and a subsequent sale by BPA to PacifiCorp.

A number of BPA's customers have filed legal challenges of BPA's Settlement Agreements with investor-owned utilities. PacifiCorp has agreed in this Financial Settlement Agreement that it will agree to a reduction in its cash payment to $38 per MWh if any of BPA's publicly-owned and cooperative customers enter into a settlement agreement regarding challenges to the BPA actions that provide benefits to the residential and small farm customers of PacifiCorp. PacifiCorp may choose which customers and which claims it will settle, but agrees to reduce the cash payments from BPA if it settles any claim with any publicly-owned or cooperative customer to any of the following: (1) the Settlement Agreement; (2) this Agreement; (3) the Residential Purchase and Sale Agreement Record of Decision (ROD); (4) the Power Subscription Strategy RODs, including the Residential Exchange Program Settlement ROD; and (5) the application of the 7(b)(2) surcharge to BPA's WP-02 rates.

1. Cash Payment Adjustments Due to Application of Safety Net Cost Recovery Adjustment Clause (SN CRAC) and Dividend Distribution Clause (DDC) to BPA Firm Power Sales

BPA has negotiated one exception to the cash payment it makes to PacifiCorp under this Agreement. BPA's wholesale power rates include an SN CRAC. The SN CRAC is designed to ensure that BPA can cover its costs as soon as possible if BPA fails to meet one of its Treasury payments. If BPA is in a situation where it must impose the SN CRAC under its wholesale power rates, BPA will reduce its monthly payments to PacifiCorp under this Agreement. BPA's monthly payments would be reduced in the same amount as the increase in rates to BPA's preference customers under the SN CRAC for the amount of firm power that BPA has converted to cash payments under the Agreement. This provision ensures that PacifiCorp's residential and small farm customers share in the resolution of any emergency that threatens BPA's ability to recover its costs.

BPA's wholesale rates also include a DDC. The DDC is designed to return money to BPA's wholesale power customers if market and other conditions result in BPA's cash reserves reaching certain levels. BPA has agreed that it will make an offsetting adjustment to PacifiCorp's monthly payments if BPA has made payments to its firm power customers under the DDC. These increased payments are only made after DDC payments made to firm power customers and are limited to the amount of any reduction in payments due to imposition of the SN CRAC.

(a) Adjustment to Cash Payments Resulting from SN CRAC and SN CRAC Balancing Account

This section of the Agreement calculates the reduction in the monthly payment to PacifiCorp under the Agreement in the event that BPA imposes an SN CRAC on its firm power customers. BPA records the amount of any such reductions in an SN CRAC Account.

(b) DDC Balancing Account

This section determines if BPA has made DDC payments to its firm power customers. BPA records the amount it would have paid a preference customer for 226 aMW of power in Contract Year 2002 and 251 aMW in each year of Contract Years 2003-2006. BPA records such amount in a DDC Account.

(c) Adjustment to Cash Payments Resulting from Amounts in SN CRAC Account and DDC Account

There are three situations where BPA increases the monthly payment to PacifiCorp to reflect reduced payments from imposition of an SN CRAC. The first situation occurs when BPA has imposed an SN CRAC and then makes a DDC payment at a later date. BPA has agreed that it will increase the cash payment under this Agreement within nine months of the first DDC payment for a period of six months. The increased payments are designed to return any reduction in payments recorded in the SN CRAC account up to the amounts recorded in the DDC Account.

The second situation occurs when BPA imposes an SN CRAC after BPA has made DDC payments at an earlier date. BPA has agreed that it will increase the cash payment under this Agreement within nine months of the SN CRAC reduction for a period of six months. The increased payments are designed to return any reduction in payments recorded in the SN CRAC Account up to the amounts recorded in the DDC Account.

The third situation occurs when BPA has increased PacifiCorp's payment for a six-month period. BPA agrees to increase the monthly payments for the next six month period as necessary to bring the balance in the SN CRAC Account or the DDC Account to zero, whichever is smaller. BPA agrees that it will make payments for the remainder of any six-month period that extends beyond the end of the Agreement, if necessary.

2. Payment Provisions

This section of the Agreement provides that BPA will pay PacifiCorp the monthly cash payments as determined in sections 4(a), 4(b), and 4(c) within 30 days of the end of the calendar month for which cash payments are due (Due Date). After the Due Date, a late payment charge is calculated at a prescribed rate. This section also provides that BPA will pay by electronic funds transfer using PacifiCorp's established procedures.

3. Load Reduction Contingency

When BPA proposed that its customers all contribute to BPA's rate reduction efforts, a number of customers and other interested stakeholders requested that BPA include a provision that ensured that any single customer would not be the only customer modifying its contract to reduce its obligation on BPA. BPA agreed to include a load reduction contingency provision that operated to terminate the customer's obligation to BPA if certain contingencies occurred. BPA has offered to include this provision in all of its rate reduction contracts where customers are taking actions that are valued below their market value. Under the Financial Settlement Agreement, BPA's payment to PacifiCorp will increase from $20 to $38 per MWh if any of the contingencies occur on the effective date for the particular contingency. These contingency provisions only apply to payments during the period from October 1, 2001, until September 30, 2002. Any contingencies that are effective after that date will have no effect on payments to PacifiCorp.

The first contingency is whether BPA adopts the proposed rate case settlement entered into by the Joint Customer Group and BPA staff. If the Administrator elects to not adopt that settlement in his final decisions in Docket No. WP-02, the load reduction contingency occurs and the payments to PacifiCorp will increase effective October 1, 2001. Under such settlement proposal, BPA would implement a Load Based Cost Recovery Adjustment Clause (LB CRAC) that assumes that BPA will purchase from the wholesale market any remaining amounts of power needed to augment BPA's system to serve its Subscription obligations.

The second contingency is whether BPA achieves a sufficient amount of rate reduction agreements with its public agency, investor-owned utility and direct service industrial customers during the first six-month period of the LB CRAC calculation. The second contingency measures the amount of purchases BPA makes from the market in the LB CRAC calculation excluding purchases from BPA's public agency, investor-owned utility and direct service industrial customers during the period from April 10, 2001, through the calculation of the LB CRAC in late June. If BPA does not achieve approximately 1450 aMW over the initial six-month period in reductions of market purchases, the load reduction contingency occurs and payments to PacifiCorp will increase effective on October 1. This provision assures any individual customer that they are not the only customer participating.

The third contingency is whether BPA achieves a sufficient amount of rate reduction agreements with its public agency, investor-owned utility and direct service industrial customers during the second six-month period of the LB CRAC calculation. The third contingency measures the amount of purchases BPA makes from the market in the LB CRAC calculation excluding purchases from BPA's public agency, investor-owned utility and direct service industrial customers during the period from April 10, 2001, through the calculation of the LB CRAC in late June and extensions of purchases with such customers entered into prior to April 10, 2001. If BPA does not achieve approximately 1250 aMW over the second six-month period in reductions of market purchases, the load reduction contingency occurs and payments to PacifiCorp will increase effective on April 1. This provision assures any individual customer that they are not the only customer participating during this period.

The fourth contingency measures the end of the load reduction emergency by examining the amount of direct service industrial load BPA forecasts to serve in its calculation of the LB CRAC. If the forecast amount of direct service industrial load exceeds 400 aMW per month over the six month period of a LB CRAC calculation, the load reduction contingency occurs and payments to PacifiCorp will increase at the start of the six month period included in the calculation of the LB CRAC.

The fifth contingency measures the end of the load reduction emergency by examining the actual amount of direct service industrial load served by BPA. Once BPA starts serving more than 400 aMW per month during any six-month period, the load reduction contingency occurs and payments to PacifiCorp will increase at the start of the month following the determination.

4. No Other Adjustments to Cash Payments

Section 4(f) of the Agreement clarifies that except as provided in sections 4(a), 4(b), 4(c), and 4(e), there are no other adjustments to the cash payment amounts under the Agreement.

E. PASSTHROUGH OF BENEFITS

Section 5(c)(3) of the Northwest Power Act provides that the benefits of the REP are to be passed through directly to a utility's residential loads within a State. 16 U.S.C. § 839c(c)(3). Similarly, the Parties provide that the benefits from the Settlement Agreement and the Agreement be passed through in such a manner. Section 5 of the Agreement therefore provides that, except as otherwise provided in the Agreement, cash payment amounts received by PacifiCorp from BPA under the Agreement must be passed through, in full, to each residential and small farm consumer, as either (1) monetary payments, or (2) as otherwise directed by the applicable State regulatory authority. BPA has audit rights, as provided in section 6 of the Agreement to ensure that, even if benefits are passed through as directed by the applicable state regulatory authority, BPA can require that benefits only be passed through to eligible Residential Load. Section 5(b) of the Agreement ensures that cash benefits under the Agreement must be distributed to PacifiCorp's Residential Load in a timely manner. This is accomplished by providing that the amount of benefits held in an account will not exceed the expected receipt of monetary payments from BPA under the Agreement over the next 180 days. If the annual monetary payment is less than $600,000, section 5(b) permits PacifiCorp to distribute benefits on a less frequent basis provided that distributions are made at least once each contract year. Section 5(c) of the Agreement provides that the benefits will be passed through consistent with procedures developed by PacifiCorp's State regulatory authority(s). Cash payments under the Agreement will be identified on PacifiCorp's books of account in order that such benefits can be easily tracked. In addition, funds will be held in an interest bearing account, and will be maintained as restricted funds, unavailable for the operating or working capital needs of PacifiCorp. Also, benefits will not be pooled with other monies of PacifiCorp for short-term investment purposes. These provisions ensure that benefits will be provided only to PacifiCorp's residential and small farm consumers. Section 5(d) provides that cash benefits under this Agreement can be used for the buydown of residential and small farm loads. This allows PacifiCorp's residential and small farm consumers to receive the benefits of the Settlement and also allows PacifiCorp to assist the region in reducing its market purchases that lead to higher rates.

F. AUDIT RIGHTS

Section 6 of the Agreement establishes audit rights that are virtual identical to the audit rights in the Settlement Agreement. Basically, BPA retains the right to audit PacifiCorp at BPA's expense to determine whether the benefits provided to PacifiCorp under the Agreement were provided only to PacifiCorp's eligible Residential Load. BPA retains the right to take action consistent with the results of the audit to require the passthrough of benefits to eligible Residential Load. BPA's right to conduct audits of PacifiCorp with respect to a Contract Year expires 60 months after the end of the Contract Year. As long as BPA has the right to audit PacifiCorp under the Agreement, PacifiCorp will maintain all relevant records.

G. ASSIGNMENT

Section 7 of the Agreement addresses the assignment of the benefits of the Agreement. This section reflects the need for flexibility in the provision of benefits to PacifiCorp's residential and small farm customers in light of the uncertainty of the energy industry regarding deregulation or other efforts that could restructure state retail electric service. These provisions are virtually identical to the assignment provisions in the Settlement Agreement. Section 7(a) requires PacifiCorp to assign benefits to BPA if a Qualified Entity serves Residential Load formerly served by PacifiCorp (unless BPA has approved an agency agreement for such Qualified Entity), or BPA has approved a state program for the passthrough of benefits by a distribution utility.

Section 7(b) of the Agreement provides that the Agreement is binding on any successors and assigns of the Parties, but that neither Party may otherwise transfer or assign this Agreement without the other Party's written consent. Such consent cannot be unreasonably withheld, provided that PacifiCorp agrees it will assign benefits under this Agreement subject to the following terms and conditions: (1) PacifiCorp will quantify an amount of Residential Load each month served by Qualified Entities that would have been eligible to receive benefits if served by PacifiCorp, and provide written notice of such amount to BPA; (2) PacifiCorp will assign to BPA during the month following such notice a share of the total benefits, whether or not PacifiCorp continues to serve such Residential Load. The Residential Load of PacifiCorp will not include Residential Load receiving benefits over a new distribution system; (3) If the passthrough of benefits is made to consumers with PacifiCorp acting as agent, then PacifiCorp will retain the cash payments assigned to BPA and use such cash payments to provide benefits to individual residential and small farm consumers.

Section 7(c) of the Agreement provides that PacifiCorp may continue to pass through benefits to individual residential and small farm consumers under this Agreement not served by PacifiCorp if (i) PacifiCorp is acting as the agent under an agreement entered into between PacifiCorp and a Qualified Entity which has been approved by PacifiCorp's applicable state regulatory authority and BPA; or (ii) BPA has approved a program developed by the applicable state regulatory authority providing for the passthrough of benefits received by PacifiCorp under the Agreement to all its residential and small farm consumers acting in its capacity as a distribution utility.

Section 7(d) of the Agreement provides that if a Qualified Entity eligible to purchase firm power under section 5(b) of the Northwest Power Act acquires all or a portion of the distribution system serving the Residential Load of PacifiCorp, PacifiCorp will assign a share of the total benefits to BPA for the remaining term of the Agreement.

H. CONSERVATION AND RENEWABLES DISCOUNT

The rates contained in BPA's May Proposal include a Conservation and Renewables Discount (C&R Discount). The C&R Discount is designed to encourage the development of conservation and renewable energy resources. Section 8 of the Agreement addresses how the C&R Discount will apply to the cash benefits provided to PacifiCorp. Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules, including GRSPs, BPA will pay PacifiCorp an amount equal to the C&R Discount for 251 aMW for each Contract Year during the October 1, 2001, through September 30, 2006, period, unless PacifiCorp has notified BPA's Power Business Line (PBL) before August 1, 2001, that it will not participate in the C&R Discount. This is to ensure that PacifiCorp's residential and small farm consumers will retain the benefits they would have received if PacifiCorp had provided power benefits instead of cash benefits. Where PacifiCorp is willing to assist BPA's rate mitigation efforts by receiving cash benefits instead of power, PacifiCorp should not be penalized for such actions.

To retain the full amount of the C&R Discount, PacifiCorp must satisfy all obligations associated with the C&R Discount as specified in BPA's applicable Wholesale Power Rate Schedules, including GRSPs, and the C&R Discount implementation manual. PacifiCorp will reimburse BPA for any amount it received but for which it did not satisfy such obligations.

I. GOVERNING LAW AND DISPUTE RESOLUTION

Section 9 of the Agreement addresses the law governing the Agreement and the manner in which disputes under the Agreement will be resolved. This section is virtually identical to the governing law and dispute resolution section of the Settlement Agreement. In summary, the Agreement will be interpreted consistent with and governed by Federal law. Final actions subject to section 9(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. Other contract disputes or contract issues between the Parties arising out of this Agreement will be subject to binding arbitration. The Parties will make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties will continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

J. NOTICE PROVIDED TO RESIDENTIAL AND SMALL FARM CUSTOMERS

Section 10 of the Agreement provides that PacifiCorp will ensure that any entity that issues customer bills to PacifiCorp's residential and small farm consumers will provide written notice on such customer bills that their benefits are "Federal Columbia River Benefits supplied by BPA."

K. STANDARD PROVISIONS

Section 11 of the Agreement includes a number of standard contract provisions. These provisions are virtually identical to those in the Settlement Agreement. These provisions include a requirement for a written instrument to amend the Agreement; conditions governing the exchange of information and the confidentiality of such information; a provision that Agreement constitutes the entire agreement between the Parties; a provision that incorporates the exhibits into the Agreement by reference; a provision that no other person is a direct or indirect legal beneficiary of, or has any direct or indirect cause of action or claim in connection with the Agreement; and a provision providing that any waiver at any time by either Party to the Agreement of its rights under the Agreement will with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

L. TERMINATION OF AGREEMENT

Section 12 of the Agreement address termination of the Agreement. Basically, if BPA does not adopt the Partial Stipulation and Settlement Agreement in the WP-02 Wholesale Power Rate proceeding, then PacifiCorp may, prior to September 1, 2001, and upon written notice to BPA, terminate the Agreement and Amendment No. 1 to the Settlement Agreement.

M. SIGNATURES

Section 13 provides that each signatory represents that he or she is authorized to enter into this Agreement on behalf of the Party for whom he or she signs.

CONCLUSION

The BPA Administrator has delegated the authority to execute Amendment No. 1 to the Settlement Agreement, and the Financial Settlement Agreement, to the BPA Account Executives for the respective investor-owned utilities. I have reviewed and evaluated the record compiled by BPA on the foregoing issues regarding BPA's Amendment No. 1 to the Settlement Agreement, and the Financial Settlement Agreement. Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt Amendment No. 1 to the Settlement Agreement, and the Financial Settlement Agreement. The evaluations and decisions used in the development of Amendment No. 1 to the Settlement Agreement, and the Financial Settlement Agreement, are consistent with the environmental analysis conducted for BPA's 1998 Power Subscription Strategy, BPA's Power Subscription Strategy NEPA ROD, BPA's Business Plan EIS and BPA's Business Plan ROD.

Issued at Portland, Oregon, this 23rd day of May, 2001.

/s/ Mark E. Miller

Account Executive

AMENDED RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT WITH PUGET SOUND ENERGY

ADMINISTRATOR'S RECORD OF DECISION

Bonneville Power Administration
U.S. Department of Energy

June 6, 2001

INTRODUCTION

This Record of Decision addresses the development of an Amended Settlement Agreement between Puget Sound Energy (Puget) and the Bonneville Power Administration (BPA), which replaces in its entirety Puget's Residential Exchange Program Settlement Agreement, Contract No. 01PB-12162 (Settlement Agreement). The Amended Settlement Agreement provides financial benefits to the residential and small farm consumers of Puget through a settlement of Puget's participation in the Residential Exchange Program (REP) for the period from July 1, 2001, through September 30, 2006, and provides a combination of power and monetary benefits to such consumers through a settlement of Puget's participation in the Residential Exchange Program (REP) for the period from July 1, 2006, through September 30, 2011. 16 U.S.C. § 839c(c). In order to fully understand the proposed Amended Settlement Agreement with Puget, it is helpful to understand BPA's initial development of the REP Settlements with regional investor-owned utilities (IOUs). A review of such development follows.

BACKGROUND

BPA was created in 1937 to market electric power generated at Bonneville Dam, and to construct and operate facilities for the transmission of power. 16 U.S.C. § 832-832l (1994 & Supp. III 1997). Since that time, Congress has directed BPA to market power generated at additional facilities. *Id.* § 838f. Currently, BPA markets power generated at thirty Federal hydroelectric projects, and several non-Federal projects. BPA also owns and operates approximately 80 percent of the Pacific Northwest's high-voltage transmission system. In 1974, BPA became a self-financed agency that no longer receives annual appropriations. *Id.* § 838i. BPA's rates must therefore produce sufficient revenues repay all Federal investments in the power and transmission systems, and to carry out BPA's additional statutory objectives. *See id.* §§ 832f, 838g, 838i, and 839e(a).

In the 1970's, threats of insufficient resources to meet the region's electricity demands led to passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839, *et seq.* (1994 & Supp. III 1997). In that Act, Congress, among other things, directed BPA to offer new power sales contracts to its customers. *Id.* §§ 839c, 839c(g). While Congress provided that BPA's public agency customers (preference customers) and investor-owned utility customers (IOUs) had a statutory right for service from BPA to meet their net requirements loads, Congress did not provide such a right to BPA's direct service industrial customers (DSIs). BPA was provided the authority, but not the obligation, to serve the DSIs' firm loads after the expiration of their power sales contracts in 2001. *See id.* §§ 839c(b)(1), 839d. Congress also established the Residential Exchange Program, which, as discussed in greater detail below, provides Pacific Northwest utilities a form of access to the benefits of low-cost Federal power. *Id.* § 839c(c).

A. The Residential Exchange Program (REP)

Section 5(c) of the Northwest Power Act established the REP. *Id.* § 839c(c). Under the REP, a Pacific Northwest electric utility (either a publicly owned utility, an IOU or other entity authorized by state law to serve residential and small farm loads) may offer to sell power to BPA at the utility's average system cost (ASC). *Id.* § 839c(c)(1). BPA purchases such power and, in exchange, sells an equivalent amount of power to the utility at BPA's PF Exchange rate. *Id.* The amount of the power exchanged equals the utility's residential and small farm load. *Id.* In past practice, no actual power sales have taken place. Instead, BPA provided monetary benefits to the utility based on the difference between the utility's ASC and the applicable PF Exchange rate multiplied by the utility's residential load. These monetary benefits must be passed through directly to the utility's residential and small farm consumers. *Id.* § 839c(c)(3). While REP benefits have previously been monetary, the Northwest Power Act also provides for the sale of actual power to exchanging utilities in specific circumstances. Pursuant to section 5(c)(5) of the Northwest Power Act, in lieu of purchasing any amount of electric power offered by an exchanging utility, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to the utility as part of an exchange sale. *Id.* § 839c(c)(5). However, the cost of the acquisition must be less than the cost of purchasing the electric power offered by the utility. *Id.* In these circumstances, BPA acquires power from an in lieu resource and sells actual power to the exchanging utility.

Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers and other regional parties. A utility's ASC is the sum of a utility's production and transmission-related costs (Contract System Costs) divided by the utility's system load (Contract System Load). A utility's system load is the firm energy load used to establish retail rates. BPA's current ASC Methodology was established in 1984. BPA has recognized, however, that the ASC Methodology can be revised. BPA's current ASC Methodology uses a "jurisdictional approach" in determining utilities' ASCs, which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. These data provide the starting point for BPA's determination of the ASC of each utility participating in the REP. Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs.

The schedule for filing and reviewing a utility's ASC is established in the 1984 ASC Methodology, which provides that "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the utility shall file a preliminary Appendix 1, setting forth the costs proposed by the utility and shall deliver to BPA all information initially provided to the state commission." The filing includes all testimony and exhibits filed in the retail rate proceeding. Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. BPA then has 210 days to review the filing and issue a report signed by the Administrator. During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. BPA makes adjustments as necessary.

The REP has traditionally been implemented through Residential Purchase and Sale Agreements (RPSAs), which were executed in 1981. Between 1981 and the present, Residential Exchange Termination Agreements have been negotiated with all of the previously active exchanging utilities except Montana Power Company (MPC). MPC continues to be in "deemer" status. When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. By doing so, it avoids making actual monetary payments to BPA. The amount that the utility would otherwise pay BPA is tracked in a "deemer account." At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA under an existing or new RPSA. The issue of deemer balances with IOUs is currently in dispute. Regional utilities are eligible to participate in the REP again beginning July 1, 2001, except for those utilities that have previously executed settlement agreements for terms extending beyond July 1, 2001.

B. The Comprehensive Review of the Northwest Energy System

In early 1996, the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. *See* Comprehensive Review of the Northwest Energy System, Final Report, December 12, 1996 (Final Report). The governors appointed a 20-member Steering Committee that was broadly representative of the various stakeholders in the power system to study that system and make recommendations about its transformation. *Id.* Each governor had a representative on the Steering Committee to make certain the public was educated about and involved in the Comprehensive Review. *Id.* In establishing the review, the governors stated:

The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same tine assuring the region of an adequate, efficient, economical and reliable power system.

Id. In 1996, the Steering Committee held 30 daylong meetings. *Id.* In addition, almost 400 people were involved in more than 100 meetings of various work groups reporting to the Steering Committee. *Id.* Hundreds of citizens attended the 10 public hearings that were held throughout the region on the Committee's draft report. *Id.* More than 700 written comments were received. *Id.* The Final Report was the product of that work. *Id.*

The Final Report noted that the electricity industry in the United States is in the midst of significant restructuring. *Id.* This restructuring is the product of many factors, including national policy to promote a competitive electricity generation market and state initiatives in California, New York, New England, Wisconsin and elsewhere to open retail electricity markets to competition. *Id.* This transformation is moving the industry away from the regulated monopoly structure of the past 75 years. *Id.* Today the region is served by individual utilities, many of which control everything from the power plant to the delivery of power to the region's homes or businesses. *Id.* In the future, the region may have a choice among power suppliers that deliver their product over transmission and distribution systems that are operated independently as common carriers. *Id.* There is much to be gained in this transition. *Id.* Broad competition in the electricity industry that extends to all consumers could result in lower prices and more choices about the sources, variety and quality of their electrical service. *Id.*

The Final Report also noted that there are risks inherent in the transition to more competitive electricity services. *Id.* Merely declaring that a market should become competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared. *Id.* It is entirely possible to have deregulation without true competition. *Id.* Similarly, the reliability of the region's power supply could be compromised if care is not taken to ensure that competitive pressures do not override the incentives for reliable operation. *Id.* How competition is structured is important. *Id.* It is also important to recognize the limitations of competition. *Id.* Competitive markets respond to consumer demands, but they do not necessarily accomplish other important public policy objectives. *Id.* The Northwest has a long tradition of energy policies that support environmental protection, energy-efficiency, renewable resources, affordable services to rural and low-income consumers, and fish and wildlife restoration. *Id.* These public policy objectives remain important and relevant. *Id.* The Final Report states that given the enormous economic and environmental implications of energy, these public policy objectives need to be incorporated in the rules and structures of a competitive energy market. *Id.*

The Final Report stated that, in some respects, the transition to a competitive electricity industry is more complicated in the Northwest because of the presence of BPA. *Id.* BPA is a major factor in the region's power industry, supplying, on average, 40 percent of the power sold in the region and controlling more than half the region's high-voltage transmission. *Id.* BPA benefits from the fact that it markets most of the region's low-cost hydroelectric power. *Id.* It is hampered by the fact that it has high fixed costs, including the cost of past investments in nuclear power and the majority of the costs for salmon recovery. *Id.* As a wholesale power supplier, BPA is already fully exposed to competition and is struggling to reduce its costs so that it can compete in the market. *Id.* The transition to a competitive electricity industry raises many issues for the BPA and the region. *Id.* In the near term, how can BPA continue to meet its financial and environmental obligations in the face of intense competitive pressure? *Id.* In the longer-term, when market prices rise and some of BPA's debt obligations have been retired, how can the Northwest retain the economic benefits of its low-cost hydroelectric power when the rest of the country is paying market prices? *Id.* And finally, what is the appropriate role of a Federal agency in a competitive market? *Id.*

The Final Report noted that while participants on the Comprehensive Review Steering Committee represented, by design, many divergent interests, they were fundamentally interconnected through one unifying value. *Id.* Collectively, they share an abiding interest in the stewardship of a great regional resource -- the Columbia River and its tributaries. *Id.* The river is the link that brought all the parties together and unites them in a single, overriding goal. *Id.* That goal is to protect and enhance the assets of this great natural resource for the people of the Pacific Northwest. *Id.*

The Final Report stated that the Federal power system in the Pacific Northwest has conferred significant benefits on the region for more than 50 years. *Id.* The availability of inexpensive electricity at cost has supported strong economic growth and helped provide for other uses of the Columbia River, such as irrigation, flood control and navigation. *Id.* The renewable and non-polluting hydropower system has helped maintain a high quality environment in the region. *Id.* But while the power system has produced significant benefits, these benefits came at a substantial cost to the fish and wildlife resources of the Columbia River basin. *Id.* Salmon and steelhead populations had been reduced to historic lows, and many runs were about to be listed under the Federal Endangered Species Act. *Id.* Resident fish and wildlife populations had also been affected. *Id.* Native Americans and fishery-dependent communities, businesses and recreationists had suffered substantial losses due in significant part to construction and operation of the power system. *Id.* The region's ability to sustain its core industries, support conservation and renewable resources, and restore salmon runs would be clearly threatened if the region cannot reach a consensus regional position to bring to the national electricity restructuring debate. *Id.* Without a sustainable and financially healthy power system, funding for fish and wildlife restoration could be jeopardized. *Id.*

The Final Report noted that the Governors of Idaho, Montana, Oregon and Washington, in their charge to the Comprehensive Review, and the Steering Committee in their deliberations, recognized that the electricity industry is changing, whether the region likes it or not. *Id.* The Comprehensive Review was not an initiation of change, but a response to change. *Id.* It was an effort to shape that change, to the extent shaping is possible, to ensure that the potential benefits of competition are achieved and equitably shared, environmental goals are met, and the benefits of the hydroelectric system are preserved for the Northwest. *Id.* The region's ability to shape the change in the Northwest electricity industry depends on its ability to develop a regional consensus. *Id.* If the Comprehensive Review failed to result in a consensus for regional action, the electricity industry would still be restructured. *Id.* A return to the historical industry structure is not an option. *Id.* Many of the comments received during the public hearing process on the Steering Committee's draft recommendations made it clear that this was not a widely appreciated fact. *Id.*

The Final Report summarized the Steering Committee's goals and proposals. The Steering Committee's goals for Federal power marketing were to: (1) align the benefits and risks of access to existing Federal power; (2) ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists while not compromising the security or tax-exempt status of BPA's third-party debt; and (3) retain the long-term benefits of the system for the region. *Id.* The recommendation was also intended to be consistent with emerging competitive markets and regional transmission solutions. *Id.* The mechanism proposed to accomplish these goals was a subscription system for purchasing specified amounts of power at cost with incentives for customers to take longer-term subscriptions. *Id.* Public utility customers with small loads would be able to subscribe under contracts that would accommodate minor load growth. *Id.* Subscriptions would be available first to regional customers a specified multiparty priority order, starting with preference customers, then the DSIs and the residential and small farm customers of the IOUs participating in the REP, followed by other regional customers. *Id.* Non-regional customers could subscribe after in-region customers. *Id.* Within each phase of the subscription process, longer-term contracts would have priority over shorter-term contracts if the system were oversubscribed. *Id.*

With regard to the REP, the Final Report noted that as a result of the Northwest Power Act, Northwest utilities have the right to sell to BPA an amount of power equal to that required to serve their residential and small farm customers at the utilities' average system costs and receive an equal amount of power at BPA's average system cost. *Id.* In reality, this is an accounting transaction. *Id.* No power is actually delivered. *Id.* This was intended to be a mechanism to share the benefits of the low-cost Federal hydropower system with the residential and small farm customers of the region's IOUs. *Id.* As a result of decisions made by BPA in its 1996 rate case, those benefits were reduced. *Id.* The Steering Committee acknowledged that the residential and small farm consumers of exchanging IOUs would be adversely affected by the reduction of exchange benefits. *Id.* Congress intervened for one year to stabilize the exchange benefits. *Id.* However, on October 1, 1997, there would be rate increases to the residential and small farm customers of the exchanging utilities. *Id.* The Steering Committee encouraged the parties to continue settlement discussions and to explore other paths to ensure that residential and small farm loads receive an equitable share of Federal benefits. *Id.*

C. BPA's Power Subscription Strategy

The concept of power subscription came from the Comprehensive Review of the Northwest Energy System, which, as noted above, was convened by the governors of Idaho, Montana, Oregon, and Washington to assist the Northwest through the transition to competitive electricity markets. The goal of the review was to develop recommendations for changes in the region's electric utility industry through an open public process involving a broad cross-section of regional interests. In December 1996, after over a year of intense study, as noted above, the Comprehensive Review Steering Committee released its Final Report. The Final Report recommended that BPA capture and deliver the low-cost benefits of the Federal hydropower system to Northwest energy customers through a subscription-based power sales approach. In early 1997, the

Governor's representatives formed a Transition Board to monitor, guide, and evaluate progress on these recommendations.

Public process is integral to BPA's decisionmaking. With the changing marketplace for electric power, there is considerable regional interest in defining how and to whom the region's Federal power should be sold. The public was involved at several levels during the development of BPA's Power Subscription Strategy. In addition to the public meetings held specifically on Subscription, BPA sought input from a wide range of interested and affected groups and individuals. BPA collaborated with Northwest Tribes, interest groups, Congressional members, the Department of Energy (DOE), the Administration, and BPA's customers to resolve issues, understand commercial interests, and develop strong business relationships.

In early 1997, BPA and the Pacific Northwest Utilities Conference Committee (PNUCC) invited 2800 interested parties throughout the Pacific Northwest to help further define Subscription. The collaborative effort to design a Subscription contract process began with a public kickoff meeting on March 11, 1997. At this meeting, a BPA/customer design team presented a proposed work plan, including a description of the environmental coverage for Subscription. An important element of the work plan was the formation of a Subscription Work Group. The Work Group, which normally met in Portland twice a month from March 1997 through September 1998, was open to the public. On average, 40-45 participants--representing customers, customer associations, Tribes, State governments, public interest groups, and BPA--attended. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation.

Over 18 months, BPA, its customers and other interested parties discussed and clarified many Subscription issues. During this time, BPA and the public confirmed goals, defined issues, developed an implementation process for offering Subscription, and developed proposed product and pricing principles. The following is a chronology of events.

On March 11, 1997, a public meeting was held in Portland to kick off the Federal Power Marketing Subscription development process. The following topics were discussed at this meeting: the role of the Regional Review Transition Board in the Subscription process; the Draft Work Plan that was developed to guide the development process; the issues that relate to the Subscription process that need to be addressed; and the National Environmental Policy Act (NEPA) strategy for this effort. The Work Plan identified a "self-selected" work group to lead this effort (anyone eligible to participate).

On March 18, 1997, a "Federal Power Marketing Subscription" web site was established at BPA to help disseminate information about the Subscription Process.

On March 19, 1997, the Federal Power Subscription Work Group held its first meeting in Portland, Oregon. The Work Group held a total of 33 meetings (approximately two per month), ending on September 22, 1998.

On September 9, 1997, a Progress Report was presented to the Transition Board.

On November 25, 1997, an update meeting for stakeholders was held in Spokane to discuss progress to date and next steps. A summary of the meeting, along with the meeting handout/slide presentation and concerns/issues raised, was posted to the web site.

In January 1998, an article entitled "*Subscription Process Underway*" was published in the BPA Journal, (January 1998).

On April 30, 1998, BPA's Power Business Line (PBL) established a web site to disseminate information about a customer group's Slice of the System Proposal. The Subscription Work Group evaluated the Slice proposal, and the proposal as modified by BPA continued to be developed in a subgroup through January 1999. BPA's pricing of the Slice product was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's Record of Decision (ROD), WP-02-A-02.

In June 1998, as part of the Issues '98 process, BPA published Issues '98 Fact Sheet #3: Power Markets, Revenues, and Subscription. Issues '98 (June/Oct. 1998). The fact sheet discussed implementation approaches being considered by the Subscription Work Group so participants in the Issues '98 process could comment. As part of Issues '98 BPA conducted a series of meetings around the region. Issues related to Subscription were key topics in the discussions at those meetings. The public comment period for Issues '98 closed June 26, 1998.

On June 8, 1998, BPA's PBL established a web site to disseminate information about development of the power rates that would be used in the Subscription contracts beginning October 1, 2001. Preliminary discussions regarding development of the power rates occurred in a series of informal public meetings and continued in workshops before BPA's initial proposal was published in early 1999.

On June 18, 1998, the third Subscription public meeting was held in Spokane to present, discuss, and collect comments on the various components related to Subscription. The meeting slide presentation and summary of the meeting were posted to the web site.

On September 18, 1998, BPA released its Power Subscription Strategy Proposal for public comment. Accompanying the proposal was a press release entitled "Spreading Federal Power Benefits" and a Keeping Current publication entitled "Getting Power to the People of the Northwest, BPA's Power Subscription Proposal for the 21st Century." Keeping Current (Sept. 1998). On September 25th, an electronic version of the BPA Power Product Catalog was posted to the web site.

On September 22, 1998, the Federal Power Subscription Work Group held its final meeting in Portland, Oregon.

Subscription issues were discussed at the "Columbia River Power and Benefits" conference on September 29, 1998, in Portland, Oregon. Over 250 people attended. Conference notes were posted to BPA's web site.

On September 30, 1998, BPA's Energy Efficiency organization established a web site to help disseminate information on the proposal for a Conservation and Renewable Discount. Development of the discount continued in a series of meetings through January 1999. Development of the discount was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's ROD, WP-02-A-02.

The public was invited to participate in two comment meetings on the Subscription Proposal; one in Spokane, Washington, on October 8, 1998; the other in Portland, Oregon, on October 14.

BPA developed the Power Subscription Strategy Proposal after considering the efforts of the Subscription Work Group, public comments on Subscription, and the broad information from Issues '98. The Proposal incorporated the information received from customers, Tribes, fish and wildlife interest groups, industries and other constituents. It laid out BPA's strategy for retaining the benefits of the Federal Columbia River Power System (FCRPS) for the Pacific Northwest after 2001. The comment period on the proposal closed October 23, 1998, although all comments received after that date were considered in the Power Subscription Strategy ROD and the NEPA ROD.

During the spring and summer of 1998, BPA conducted extensive public meetings with all interested parties regarding the development of BPA's Power Subscription Strategy. At the conclusion of these lengthy discussions, on September 18, 1998, BPA released a Power Subscription Strategy Proposal for public review. During the comment period BPA received nearly 200 responses to the proposal comprising nearly 600 pages of comments. After review and analysis of these comments, BPA published its final Power Subscription Strategy on December 21, 1998. *See* Power Subscription Strategy, and Power Subscription Strategy, Administrator's ROD. At the same time, the Administrator published a National Environmental Policy Act (NEPA) ROD that contained an environmental analysis for the Power Subscription Strategy. This NEPA ROD was tiered to BPA's Business Plan ROD (August 15, 1995) for the Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995). The purpose of the Subscription Strategy is to enable the people of the Pacific Northwest to share the benefits of the FCRPS after 2001 while retaining those benefits within the region for future generations.

The Subscription Strategy also addresses how those who receive the benefits of the region's low-cost Federal power should share a corresponding measure of the risks. The Subscription Strategy seeks to implement the subscription concept created by the Comprehensive Review in 1996 through contracts for the sale of power and the distribution of Federal power benefits in the deregulated wholesale electricity market. The success of the Subscription process is fundamental to BPA's overall business purpose to provide public benefits to the Northwest through commercially successful businesses.

The Subscription Strategy is premised on BPA's partnership with the people of the Pacific Northwest. BPA is dedicated to reflecting their values, to providing them benefits and to expanding and spreading the value of the Columbia River throughout the region. In this respect, the Strategy had four goals:

> Spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region;
>
> Avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions;
>
> Allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and
>
> Provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies.

The Power Subscription Strategy describes BPA decisions on a number of issues. These include the availability of Federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. The Power Subscription Strategy discussed some issues that would not be finally decided in the Strategy. Most of these issues were decided in BPA's 2002 power rate case, although some were decided in other forums, such as the transmission rate case, which concluded recently. For example, while the Strategy documents BPA's intention to implement a rate discount for conservation and renewable resources, the final design of that discount was developed in BPA's 2002 power rate case. Other issues to be decided in the 2002 power rate case include the design and application of the CRAC, which rates apply to which sales, and the design of the Low Density Discount (LDD). Customers raised issues regarding the application of other customers' non-Federal resources to serve regional load. These resource issues involve factual determinations under section 3(d) of the Act of August 31, 1964, P.L. 88-552 (Regional Preference Act), and section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), which BPA could not address in the Power Subscription Strategy and which were not made a part of the decisions in the Subscription Strategy ROD.

While BPA's Power Subscription Strategy did not establish any rates or rate designs, rate design approaches identified in the Power Subscription Strategy were part of BPA's initial power rate proposal, which was published in 1999. The comments received during the Subscription public process regarding the various rate-related issues were addressed in BPA's 2002 power rate case, which included extensive opportunities for public involvement.

BPA's Power Subscription Strategy provided a framework for the 2002 power rate case and Subscription power sales contract negotiations. The Subscription window was to remain open 120 days after the 2002 Final Power Rate Proposal, Administrator's ROD, was signed by the BPA Administrator, providing relatively certain information to potential purchasers regarding rates.

One element the Power Subscription Strategy proposal was a settlement of the REP for regional IOUs for the post-2001 period. The Power Subscription Strategy proposed that IOUs may agree to a settlement of the REP in which they would be able to receive benefits equivalent to a purchase of a specified amount of power under Subscription for their residential and small farm consumers at a rate expected to be approximately equivalent to the PF Preference rate. Under the proposed settlement, residential and small farm loads of the IOUs would be assured access to the equivalent of 1,800 aMW of Federal power for the FY 2002-2006 period and 2,200 aMW of Federal power for the FY 2007-2011 period.

The Power Subscription Strategy noted that BPA would set the physical and financial components of the Subscription amount, by year, in the negotiated Subscription settlement contracts. Any cash payment would reflect the difference between the market price of power forecasted in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads would be in equal hourly amounts over the period.

The Power Subscription Strategy proposed that BPA would offer five-year and 10-year Subscription settlement contracts for the IOUs. Under both contracts, the Subscription Strategy proposed that BPA would offer and guarantee 1,800 aMW of power and/or financial benefits for the FY 2002-2006 period. At least 1,000 aMW would be met with actual BPA power deliveries. The remainder could be provided through either a financial arrangement or additional power deliveries, depending on which approach was most cost-effective for BPA. The IOUs' settlement of rights to request REP benefits under section 5(c) of the Northwest Power Act would be in effect until the end of the contract term. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997).

Under the 10-year settlement contract, in addition to the benefits provided during the first five years, BPA proposed to offer and guarantee 2,200 aMW of power or financial benefits for the FY2007-2011 period. BPA intended for this 2,200 aMW to be comprised solely of power deliveries. The IOUs' settlement of rights to request REP benefits under section 5(c) would be in effect until the end of the 10-year term of the contract. In the event of reduction of Federal system capability and/or the recall of power to serve its public preference customers during the terms of the five-year and 10-year contracts, BPA would either provide monetary compensation or purchase power to guarantee power deliveries.

In summary, residential and small farm loads of the IOUs could receive benefits from the Federal system through one of two ways. An IOU could participate in the established

REP or it could participate in a settlement of the REP through Subscription. If an IOU chose to request REP benefits under section 5(c), then the Subscription settlement amount for all the IOUs would be reduced by the amount that would have gone to the exchanging utility.

D. Power Subscription Strategy Supplemental ROD

As noted above, on December 21, 1998, the BPA Administrator issued a Power Subscription Strategy and accompanying ROD, which set the agency's PBL on a course to establish power rates and offer power sales contracts in anticipation of the expiration of current contracts and rates on September 30, 2001. The Strategy and ROD were the culmination of many public processes that came together to form the framework to equitably distribute in the Pacific Northwest the electric power generated by the FCRPS.

BPA's 1998 Power Subscription Strategy served to guide BPA in accomplishing its goals. After adoption of the Strategy, however, developments occurred that prompted BPA to seek, in some instances, additional comment from customers and constituents on new issues. The Strategy contemplated further public processes to implement its goals. BPA's 2002 power rate case, ongoing since August 1999, was completed on May 8, 2000. BPA and its customers continued discussions on power products and power sales contract prototypes, and the Slice of System product was further defined. In a December 2, 1999, letter, BPA sought comment from customers and constituents on some of these new issues, specifically, the length of the Subscription window for power sales contract offers, the actions required of new small utilities during this window to qualify for firm power service, and new developments with respect to General Transfer Agreements. Other issues arose independently, such as new large single loads (NLSL) under the Northwest Power Act, duration of the new power sales contracts, and a new contract clause regarding corporate citizenship. BPA also undertook a comment process on the amount and allocation of power and financial benefits to provide the IOUs on behalf of their residential and small farm consumers. On November 17, 1999, BPA sent a letter to all interested parties requesting comments on two specific issues: (1) whether the amount of the proposed IOU settlement should be increased by 100 aMW from 1800 aMW to 1900 aMW for the FY 2002-2006 period; and (2) the manner in which the settlement amount should be allocated among the individual IOUs.

1. Total Amount of IOU Settlement Benefits

BPA's intent in the Power Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region. The Subscription Strategy enabled the benefits of the FCRPS to flow throughout the region, whether currently served by publicly owned or privately owned utilities.

The Power Subscription Strategy provided that residential and small farm loads of the IOUs, through settlement of the REP, would be provided access to the equivalent of 1800 aMW of Federal power for the FY 2002-2006 period. At least 1000 aMW of the 1800 aMW would be served with actual BPA power deliveries. The remainder would be provided through either a financial arrangement or additional power deliveries depending on which approach was most cost-effective for BPA.

The four Pacific Northwest state utility commissions (Commissions), in a letter dated July 23, 1999, requested that BPA increase the amount of the settlement from 1800 aMW to 1900 aMW for the FY 2002-2006 period. This request was made in order for the Commissions to arrive at a joint recommendation for allocating the settlement benefits among the IOUs for both the FY 2002-2006 and FY 2007-2011 periods. Many parties supported this increase for many reasons, including: (1) the increase is a wise policy decision and it helps to ensure that the regional interest in the system and preserving the system as a valuable benefit in the Northwest will be shared as broadly as possible among the region's voters; (2) the increase is appropriate in order for BPA to achieve the stated Subscription Strategy goal to "spread the benefits of the Federal Columbia River Power System as broadly as possible, with special attention given to the residential and rural customers of the region," *see* Power Subscription Strategy at 5; (3) the increase creates a fair and reasonable settlement to the REP for the IOUs; (4) the increase to the settlement staves off contentious issues surrounding the traditional REP as well as provides a fair allocation of power to the IOUs; and (5) the increase will help ensure an appropriate sharing of benefits of Federal power among the residential ratepayers in the Northwest.

After review of the comments, BPA found the arguments for increasing the IOU settlement amount by 100 aMW to be compelling. BPA determined that the conditions surrounding the proposed increase to the proposed Subscription settlement of the REP were expected to be met. Therefore, BPA increased the amount of total benefits for the proposed settlements of the REP with regional IOUs from 1800 aMW to 1900 aMW.

2. Allocation of Settlement Benefits Among IOUs

In the Power Subscription Strategy, BPA noted its intent to request comments from interested parties regarding the amounts of Subscription settlement benefits that should be provided to individual IOUs. BPA also noted that the Commissions indicated that they would collaborate on an allocation recommendation. After review of all comments, BPA would determine the appropriate amounts to be allocated to the individual IOUs.

BPA solicited the Commissions' views on the proposed allocation of settlement benefits. This was appropriate because the Commissions have traditionally been responsible for establishing retail electric rates for residential consumers of the regional IOUs, including the credit applied to those rates to reflect benefits of the REP as determined by BPA. The Commissions also have a statutory responsibility to the residential consumers of the IOUs in their particular state jurisdiction. Furthermore, because of these responsibilities, a joint recommendation by the Commissions would likely reflect a fair allocation of benefits among the residential consumers of the Northwest states and would enhance the likelihood of BPA delivering the benefits in a way that would work for each state and its consumers.

The Commissions collaborated and submitted a joint recommendation on the proposed allocation of the settlement benefits. They noted that their recommendation reflects many different considerations, including the amount of residential and small farm load eligible for the REP, the historical provision of REP benefits, the REP benefits received in the last five-year period ending June 30, 2001, rate impacts on qualifying customers, and the individual needs and objectives of each state. BPA reviewed the Commissions' recommendation and determined that this proposal was a reasonable approach upon which to take public comment.

Virtually all commenters supported the allocation recommended by the Commissions and proposed by BPA. The reasons for such support included: (1) it is appropriate for BPA to weigh heavily the Commissions' joint recommendation concerning the allocation of benefits; (2) the Commissions are the best arbiters of the settlement among the IOUs; and (3) the proposed allocation establishes access to a level of benefits that recognizes changed market conditions while at the same time addresses the needs and issues important to each of the four states. It is worthy of note that BPA's allocation has received support from diverse customer and interest groups: publicly owned utilities, IOUs, the Commissions, state agencies, and a city commission. BPA concluded that the following allocation amounts would be incorporated into the proposed settlement contracts with the individual IOUs that choose to settle the REP:

	Amount of Settlement (aMW) FY2002-2006	Amount of Settlement (aMW) FY2007-2011
Avista Corp. 1/	90	149
Idaho Power Company 1/	120	225
Montana Power Company	24	28
PacifiCorp (Total)	476	590
PacifiCorp (UP&L)	*140*	*140*
PacifiCorp (PP&L – WA) 1/	*83*	*109*
PacifiCorp (UP&L – OR) 1/	*253*	*341*
Portland General Electric	490	560
Puget Sound Energy (PSE)	700	648
Total	1900	2200

1/ BPA also concluded that the allocation of benefits among the states served by these multi-state utilities would be based on the forecasts of the respective state residential and small farm loads at the time the IOU signs its Settlement Agreement.

E. BPA's Section 5(b)/9(c) Policy

As BPA recognized that its existing long-term power sales contracts would soon expire, BPA proposed to establish a policy to guide the agency in making determinations of the net requirements of its utility customers in order to offer Federal power under new contracts. (For the most part, existing power sales contracts expire by October 1, 2001.) A net requirements policy is an important component to BPA's execution and implementation of new power sales contracts. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a contract to each requesting public body, cooperative, and investor-owned utility to meet each utility's regional firm load net of the resources used by the utility to serve its firm power consumer load. 16 U.S.C. § 839c(b)(1) (1994 & Supp. III 1997). In making this determination, BPA has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), and section 3(d) of the Regional Preference Act, 16 U.S.C. § 837b(d) (1994 & Supp. III 1997).

BPA provided two opportunities for public review and comment in developing its proposed policy. On May 6, 1999, BPA published its initial policy proposal, entitled "Opportunity for Public Comment Regarding Bonneville Power Administration's Subscription Power Sales to Customers and Customer's Sale of Firm Resources," 64 Fed. Reg. 24,376 (1999). BPA held two public meetings to discuss this policy. The first meeting was held on May 27, 1999, in Spokane, Washington. The second meeting was held on June 2, 1999, in Portland, Oregon. On June 3, 1999, the thirty-day comment period was extended by BPA through June 30, 1999.

After reviewing and considering the comments received on the initial policy proposal, particularly those that requested that BPA provide a second round of review and comment, BPA issued a revised policy proposal on October 28, 1999, entitled "Revised Draft Policy Proposal Regarding Subscription Power Sales to Customers and Customer's Sales of Firm Resources," 64 Fed. Reg. 58,039 (1999). BPA reviewed and considered the comments received on the revised policy. On May 24, 2000, BPA issued its final "Policy on Determining Net Requirements of Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act," also called BPA's "Section 5(b)/9(c) Policy." BPA also issued a Section 5(b)/9(c) Policy Record of Decision.

F. IOU Settlement Agreements

After completion of the Administrator's Supplemental ROD, BPA began the development of a prototype Residential Purchase and Sale Agreement (RPSA) and a prototype Settlement Agreement. On May 5, 2000, BPA sent a letter to all interested parties requesting comments on the proposed agreements. BPA's letter included a background document describing the two agreements. BPA also enclosed copies of the draft RPSA and Settlement Agreement. BPA's letter and attachment noted that BPA's Power Subscription Strategy proposed comprehensive settlements of the REP with participating regional IOUs and that IOUs would also have the option of entering into contracts to participate in the REP. The Power Subscription Strategy also noted that public agency customers were eligible to enter RPSAs under the REP.

BPA's letter noted that BPA had prepared a prototype RPSA to implement the REP and that this prototype would be used as the basis for contracting with all eligible parties to apply for benefits under the REP. BPA requested public comment on the following issues: (1) which entities are eligible utilities to request benefits under section 5(c) of the Northwest Power Act; (2) BPA's proposal to implement the in lieu provisions of section 5(c)(5) of the Northwest Power Act through wholesale market purchases; (3) any exceptions to the limitations of section 5(c)(6) that preclude the restriction of exchange sales under section 5(c) below the amounts of power acquired from, or on behalf of, the utility pursuant to section 5(c); and (4) any comments on the terms and conditions of the prototype RPSA agreement.

BPA's letter also described BPA's proposal for comprehensive settlement of the rights of regional IOUs eligible for benefits under the REP. BPA noted that it had prepared a prototype Settlement Agreement for implementing the Subscription Strategy. The prototype provided power sales pursuant to a contract offered under section 5(b) of the Northwest Power Act. The prototype also provided for the payment of monetary benefits. BPA requested public comment on all relevant issues, including the following issues: (1) any comments on the terms and conditions of the prototype Settlement Agreement; and (2) whether the total amount of benefits and the proposed terms and conditions for settling the rights of regional IOUs to request benefits under the REP were reasonable.

BPA's letter noted that BPA's Power Subscription Strategy proposed an allocation of benefits to the region's IOUs that included both physical and monetary components. It further noted that the Administrator's Supplemental ROD for the Power Subscription Strategy proposed to offer the IOUs the equivalent of 1900 aMW of Federal power for the FY 2002-2006 period. Of this amount, at least 1000 aMW would be provided in physical power deliveries. BPA requested that each IOU notify BPA by July 21, 2000, whether they wished to participate in BPA's REP. The IOUs were not required to make an election whether to accept a settlement offer or participate in the REP through an RPSA at that time. Based on each IOU's request to participate in the REP, BPA would prepare a settlement offer for their consideration prior to October 1, 2000. At the time each IOU requested to participate in the REP in July, BPA's letter asked that each IOU identify (1) its preferred mix of physical deliveries and financial settlement; and (2) whether it would prefer a five-year or 10-year offer. BPA would only make a settlement offer including net requirements physical deliveries if the IOU could establish a net requirement for the amount of power requested.

BPA's letter requested public comment on two issues regarding the offer of physical power and financial benefits in settlement of REP rights: (1) whether BPA should require IOUs to take additional power if the combined requests of all the companies for physical deliveries are less than 1000 aMW; and (2) how BPA should limit physical deliveries to each IOU if the companies requested physical deliveries of more than 1000 aMW and such deliveries were more power than BPA was willing to offer.

Comments on all of the issues regarding the prototype agreements were to be submitted through close of business on Friday, June 9, 2000. BPA's letter noted that after receiving public comment on the proposed prototype agreements, BPA would prepare final draft prototypes based on the public comments. These draft prototypes will be published to allow IOUs to determine whether they wish to participate in the REP pursuant to an RPSA or through a settlement offer based on physical or monetary benefits. Once BPA received each IOU's request to participate in the REP, BPA would prepare a settlement offer and an RPSA for each IOU in accordance with the choices made. BPA prepared a ROD addressing the public comments on the proposed REP Settlement Agreements. A separate ROD was also issued which addressed the public comments on the proposed RPSA. BPA offered both an RPSA and a Settlement Agreement to each IOU. .

On July 28, 2000, BPA sent a letter to interested parties regarding a request by Montana Power Company (MPC) to be offered a Settlement Agreement in which the power component would be made under section 5(c) of the Northwest Power Act instead of a sale of requirements power under section 5(b) of the Act. BPA's letter noted that on May 5, 2000, BPA asked for public comment on BPA's proposed contracts for implementing the REP, including a request for comments on a proposed IOU Settlement Agreement. The Settlement Agreement BPA offered for comment on May 5 contained benefits that were comprised of proposed power sales and monetary payments. The power sales proposed under the Settlement Agreement were sales under section 5(b) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997). However, as BPA stated in its Power Subscription Strategy, released on December 21, 1998, power sales in its proposal for settling the REP could be based either under section 5(b) or 5(c) of the Northwest Power Act. In the background document included with BPA's May 5 letter, BPA noted that it had not prepared a prototype Settlement Agreement based on a power sale under section 5(c) of the Northwest Power Act, but that it would consider such proposals if they were made.

In a letter dated July 27, 2000, MPC requested that BPA provide a settlement offer including firm power benefits under section 5(c) of the Northwest Power Act. BPA prepared a draft Settlement Agreement reflecting a section 5(c) power sale. The proposed settlement, attached to BPA's July 28, 2000, letter, was very similar to the proposed agreement that BPA issued for public comment with BPA's May 5, 2000, letter. Instead of providing an IOU Firm Power Block Sales Agreement (Block Sales Agreement) for a specified amount of firm power under section 5(b) of the Northwest Power Act, this proposed section 5(c) prototype agreement provided a specified amount of firm power under a Negotiated In Lieu Agreement.

On October 4, 2000, the BPA Administrator issued a decision document entitled "Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision," which concluded that it was appropriate to offer the REP Settlement Agreements to regional IOUs. The REP Settlement Agreements were then executed the same month. One of the regional IOUs executing a settlement agreement was Puget.

G. BPA's 2002 Wholesale Power Rate Case

On August 13, 1999, BPA published a notice of BPA's *2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment*. 64 Fed. Reg. 44,318 (1999). This began a lengthy and complex hearing process that concluded with BPA's *2002 Final Power Rate Proposal, Administrator's Record of Decision*, in May 2000 (May Proposal). 16 U.S.C. § 839e(i). In July, 2000, BPA filed its proposed 2002 wholesale power rates with the Federal Energy Regulatory Commission (FERC) for confirmation and approval. 16 U.S.C. § 839e(a)(2). Subsequent to that time, however, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before. By August, it was clear that these market prices were not a short-term phenomenon. This meant that BPA's cost-based rates, which were already below the original market forecast, were even more attractive. Thus, BPA assumed that additional load would be placed on BPA, and BPA would need to purchase additional power to augment the Federal Columbia River Power System (FCRPS) supply. BPA determined that the implications for cost recovery were so serious that a stay of the rate proceeding at FERC was requested. This enabled BPA to review the events that had occurred during the summer months and to determine whether the escalating prices and increased volatility would require remedial action.

Escalating and more volatile market prices had two related effects. First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. Second, to meet this increased load obligation, BPA would need to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. BPA concluded that the May Proposal, as filed with the FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA.

During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources by 1,732 average megawatts (aMW). Due to escalating and volatile market prices, BPA estimated that expected loads would exceed the original rate case forecast by an additional 1,518 aMW. Inasmuch as the generating capability of FCRPS was already inadequate to meet the earlier load forecast, BPA would have to purchase to further augment its inventory to serve these additional loads. The cost of power to serve these unanticipated loads was not included in revenue requirements.

The combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminished the probability that rates proposed in the May Proposal would fully recover generation function costs. Absent a change to the May Proposal, Treasury Payment Probability (TPP) would be reduced to below 70 percent, a level that would fall well short of specific goals and targets. In its judgment, BPA had a serious cost recovery problem that it was obliged to address by reason of statute and Administration policy.

BPA's Amended Proposal rate case was a continuation of the WP-02 rate proceeding. It was being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. During the consideration of the Amended Proposal, however, BPA concluded that it was necessary to make additional changes to ensure BPA's cost recovery. BPA then filed a Supplemental Proposal. There were three reasons BPA filed a Supplemental Proposal. First, BPA's forecast for starting rate period reserves had dropped very substantially since the forecast in its Amended Proposal. Second, market prices available for power during the first two years of the rate period were significantly higher than BPA had forecast in the Amended Proposal. Regardless, BPA would have prepared an update to the Amended Proposal to show the impact of these revised forecasts on BPA's proposed rates. The third reason was that, as a result of discussions with the rate case parties, BPA reached a Partial Settlement Agreement with many of those parties. Part of that agreement was that BPA would file a Supplemental Proposal reflecting the Partial Settlement Agreement.

Since BPA filed its Amended Proposal in December 2000, forecasts for run-off for the water year had declined substantially. Water Year forecasts in BPA's 2002 Final Power Rate Proposal (May Proposal) and Amended Proposal assumed average water for both this FY 2001 and for the next five years of the rate period – 102.4 million acre feet (MAF). By contrast, the current year could be the second lowest runoff year on record, with current runoff forecasted at under 60 MAF. These conditions would require BPA to purchase much more power this year than expected to meet loads, at extremely high prices, and to reduce the amount of surplus energy BPA can sell this year. As BPA described in its Amended Proposal, prices in the wholesale electricity market had been extremely volatile and high. BPA had seen these increased market prices during this year. In fact, during one week in January alone, BPA purchased over $50 million in power to meet load. This was putting tremendous pressure on BPA's end-of-year reserves. End-of-year reserves translate into starting rate period reserves. In BPA's May Proposal, starting reserves were estimated to be $842 million on an expected value basis. In BPA's Amended Proposal, starting reserves expected value estimates had increased to $929 million. Then, the expected value of BPA's starting reserves estimate dropped to $309 million. There is still a significant range of uncertainty surrounding this estimation of starting reserves. This is driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices.

Starting reserves are a key risk mitigation tool in BPA's Supplemental Proposal. A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools need to be made.

Market prices during the rate period are higher in the first years of the rate period, ranging from $200/megawatthour (MWh) to $240/MWh for FY 2002, and then dropping during the last years of the rate period, to a range between $40/MWh and $60/MWh in FY 2006. This compares with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around $48/MWh, where expected prices for individual years did not vary by more than $5/MWh from the $48/MWh average.

Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market. Therefore, BPA revised the LB CRAC so that its expected revenues closely match the shape of its augmentation costs. In summary, BPA's Supplemental Proposal suggested that BPA's customers could see much higher prices during the October 1, 2001, to September 30, 2006, rate period.

H. Administrator's Call for Rate Mitigation Efforts

On April 9, 2001, the BPA Administrator delivered a speech to the citizens of the Pacific Northwest regarding the potential impact of BPA's proposed rate increase and possible ways to reduce the impact of the increase. The text of the speech follows:

Last January, I sent out a letter to Northwest citizens that caused some shock waves. That was my intent. I believe it is important to warn of bad news while there is still time to take actions that can lessen the impact. At the time, I said that, if certain conditions persisted, BPA's customers--Pacific Northwest utilities and direct-service industries--could face a significant rate increase for the wholesale power they buy from the Bonneville Power Administration. The figures I cited then were for an average rate increase of 60 percent over the five-year rate period that starts this coming October. I cautioned that the increase could be as high as 90 percent in the first year.

Unfortunately, the situation has worsened. It now appears possible that, without the kinds of action that I am about to call for today, the first-year increase could be 250 percent or more. If that were to occur, it likely would translate into doubling the retail rates in many utility service areas.

An increase of this magnitude would have widespread economic consequences. Already, we are seeing some businesses curtail operations or even close as a result of high energy prices. With such an increase, we'd surely see more businesses close and more job losses, with people with lower incomes suffering disproportionately. In addition, a weak economy frequently translates into less public support for environmental protection.

I don't believe these consequences are acceptable. More importantly, I don't believe they are inevitable. That's why I am here today to call for some very specific actions and to call on all stakeholders in the Pacific Northwest to own part of the process that will help us avert an economic blow to our region. I believe we can get the rate increase down to a manageable level, but we need to make some tough decisions, and we have little more than 60 days to do this. BPA's rates, which will go into effect in October, should be submitted to the Federal Energy Regulatory Commission in June.

First, let me review what has led us to this point. Some of it you already know. We are experiencing the second worst water year in 72 years of record-keeping. According to a report released by the Northwest Power Planning Council, if the drought persists, the hydropower generating capability in the Northwest from March through August will be 4,700 megawatts below normal over those months--the equivalent power consumed by four Seattles. The implications are ominous since the Northwest relies on hydropower for nearly three-quarters of its electricity.

But the summer drought is only the immediate crisis. We are becoming increasingly concerned about power supply for the coming winter. Canadian reservoirs, which store half the system's water, are extremely low this year, which means we could start next year with less than a full tank. If that were to happen, and especially if we have a second dry year in a row, electricity reliability wouldn't be the only thing at risk. Low reservoir levels also raise concerns for salmon and steelhead next year.

Low water combined with a tight wholesale power market and skyrocketing power prices is a devastating combination. The fiasco in California has helped drive wholesale electricity prices to unprecedented levels. When we completed our new Subscription power contracts last fall, BPA's contractual obligations added up to approximately 11,000 megawatts--about 3,000 megawatts more than our current generating resources can provide on a firm basis. The only way we can meet our obligations is to buy the vast majority of the additional power in a wholesale power market where supplies are tight and prices are sky high. This is what is driving rates up.

This year, due to the high power prices, BPA has not been able to purchase sufficient power to ensure system reliability. Consequently, we have periodically declared power system emergencies. These emergency declarations have allowed us to increase power generation from the river and reduce operations that offer benefits to migrating juvenile fish. The increased generation has reduced the amount of water that is normally stored at this time of year so that it can be used to augment spring and summer river flows. While there may be some impact on fish, by far the major impact on fish is the drought itself, not the emergency power operations. We are continuing to implement all other aspects of the federal measures for fish recovery.

Currently, we are operating the river on an emergency basis, and we can continue some fish spill or flow augmentation only as long as water volume does not dip much below current estimates. The record low runoff is a water volume of 53 million-acre feet. As of last week, the volume forecasts had dropped to 56 million-acre feet, which is 53 percent of the normal runoff. This severely limits our flexibility to do much more than meet power needs.

Beyond the current drought, high power prices are expected to continue until significant new generation and additional conservation measures are put in place. This will take a couple of years at best. And, we can't expect much help from Canada, which also is suffering drought, nor any help from California, which is in the throes of an electricity restructuring crisis.

We must focus instead on what we can control if we expect to minimize the size of the coming wholesale rate increase. The most immediate and direct way to decrease the size of next year's rate increase is quite simply to decrease the amount of power BPA has to buy in the market.

We already have taken a number of extraordinary steps in this direction. We have promoted conservation aggressively and sought voluntary curtailments in power use. We have begun to purchase curtailments from our direct service industrial customers and from irrigators who are served by our utility customers. We have offered innovative incentives for development of conservation and renewables, and we have engaged in beneficial 2-for-1 power exchanges with California. We also are continuing to collaborate with the Corps of Engineers and Bureau of Reclamation to increase the productive capability of the federal power system.

But even these extraordinary measures haven't been enough in the face of the triple whammy of historic low water conditions, an extremely tight power market and enormous volatility in power prices. We now need to up the ante if we are to get the rate increase for the next year down to a manageable level.

We literally are at a crossroads, and the region has essentially two options. Path A is to wait and see where market prices settle in June. Under this scenario, we'd rely on cost recovery mechanisms to kick up rates if prices remain high. We would take no special actions and we wouldn't push or negotiate with our customer groups to secure load reductions. The risk is that, if market prices stay the same, we could expect to see a first year rate increase in the 200 to 300 percent range, and possibly greater.

Then there's Path B, which calls for aggressive and immediate steps to reduce the size of the rate increase by reducing the amount of electricity demand put on BPA. Under this scenario, BPA would not have to buy as large an amount of power in a very expensive wholesale power market. It's a strategy that calls on our customers and other stakeholders to share a sacrifice by reducing their demands for power. It requires significant, and I mean significant, contributions from all customer groups. It could keep the first-year rate increase below 100 percent. I believe Path B is the course we must choose, so let me lay out some of the actions that will move us along this path.

As I discuss this path, let me outline the principles I believe are key to reducing rates. First, rates must be set to cover costs if we are to avoid creating a credit problem, which could lead to refusals to sell to us in the future. We must also cover our costs to ensure we preserve the benefits of the federal hydropower system over the long term, which is essentially the bottom line.

Second, the situation is urgent. We must act quickly because rates must be in effect this coming October 1. As I said earlier, our rate proposal is due in to the Federal Energy Regulatory Commission in June.

Third, our problem is caused by a significant exposure to a volatile market in the first one-to-two years of the rate period. If we are to manage a reduction in the rate increase, we must reduce our exposure to that market by reducing demand for energy, increasing our supply and minimizing the short and long-term damage to the region's economy.

Fourth, contributions to the solution are needed from all customers. We can't play a game a chicken where each party waits for the other to step forward. If that happens, no one will step forward. Each group must contribute if we are to preserve an equitable distribution of the benefits of our hydropower resource.

...

Given those principles, let me outline the actions we as a region need to take. We need a three-pronged approach that includes curtailment of power use, conservation--or more efficient use of power--and power buybacks. This needs to happen across all four states, across public and private power, and across all sectors of energy use--industrial, commercial, agricultural and residential. It will take all of us working together if we are to avoid severe economic hardships for the region. Let me be clear; what I am about to suggest requires a great deal of sacrifice, but the alternative is to suffer far more serious consequences. We are beginning negotiations now with our customers. If people don't come to the table with reductions in their demand for electricity, a very large and very damaging rate increase is inevitable.

First, we are calling on our public utility customers to make a contribution to the solution. We need every utility customer to reduce its Subscription purchases from BPA by 5 to 10 percent. BPA's rate increases will spur some of this reduction, but more focused efforts are needed if we are going to achieve significant savings. We are willing to make modest incentive payments to help achieve this, but the incentive payments cannot be large or they will defeat the intended effect.

We are running several demand-side management initiatives including a conservation and renewables discount, a conservation augmentation program and a demand exchange program. In addition, we now are discussing the potential for new programs to provide incentives to our public utility customers to adopt innovative retail rate structures that encourage their consumers to conserve energy.

Second, we are calling on investor-owned utilities to make a contribution. When our new rates go into effect this October, investor-owned utilities--or IOUs--will receive sizable benefits from BPA for their residential and small farm customers as a result of a the residential exchange. Under this program, as it is set out in the Subscription period, 1,900 average megawatts of financial and power benefits are scheduled to go to the IOUs. But, because of dramatic changes in market prices, the estimated value of these benefits has increased enormously since they were negotiated a year ago. By 2002, the value will be 10 times higher than the negotiations intended to capture. As a result, IOUs are in a position to reduce their Subscription demand significantly and still enjoy benefits in excess of anything they have experienced in the 20-year history of the residential exchange.

Third, we are asking our direct service industries--or DSIs--to agree not to take power from us for up to the first two years of the rate period in return for certain limited compensation to the companies and their workers. It is our expectation that the companies would not be able to operate given a potential tripling of our rates anyway. Coming to an agreement now that the plants will not operate would allow BPA to avoid making power purchases, thereby decreasing our rates for all remaining customers.

It is not our intention to drive the aluminum industry out of the region, but we are continuing to encourage the industry to move off of BPA power supplies after the 2006 rate period because we do not have a statutory obligation to continue to serve them. The customers we are obligated to serve--the region's retail electric utilities--need more than our current generation resources can produce. We will work with these companies to help them find a means to operate profitably in the long run without relying on BPA.

Almost all of the DSIs are already shut down until this fall, and their power is being remarketed to support Northwest needs during the current drought. These buydowns played a key role in keeping the lights on this winter and in maintaining reservoir levels higher than they otherwise would have been.

Fourth, I am urging all citizens of the Northwest to heed the call of our governors to reduce electricity consumption by 10 percent through eliminating waste and using electricity more efficiently. There are a number of common sense measures we can all take, and one good place to start right now is to go out and replace conventional light bulbs with compact fluorescents, which consume about 20 percent of the electricity used by regular bulbs for the same amount of light.

These four sets of actions that I have described are urgently needed between now and June if we are to avert grave near-term economic consequences. These are difficult actions. But, with hindsight, we can learn from the problems California experienced and seek to avoid them. We need to do everything we can to avoid power purchases in this incredibly expensive market. We also need to make sure we set rates high enough so we can cover our costs to assure generators get paid when they deliver power on a contractual basis so we don't put our credit at risk.

We also are looking to longer-term solutions that will help lead to lowering the incredible wholesale power supply prices we are currently experiencing. The fundamental problem is supply and demand being out of balance. Prompt infrastructure investments are needed in generating resources, especially gas-fired and wind-powered generation; gas pipeline capacity and storage; electric power transmission facilities; and energy conservation measures.

BPA's [proposed] rates [may] now be set on a six-month basis based on our actual costs. If wholesale power prices can be brought down quickly, through infrastructure investments and other actions, then our rates will come down in the future. The faster these actions can be taken, the quicker our rates can come down.

We already have begun plans to shore up the transmission infrastructure, and we are negotiating to purchase the output from combustion turbines and new renewable resources. We also are increasing our efforts to encourage and procure energy efficiency. We are working to implement these actions quickly, but at best, some actions, such as securing more generation, will take one-to-two years.

That's why I am calling for cooperation and sacrifices for the next two years from all parties BPA serves. If the region cannot or will not take the actions necessary to reduce the rate hike, we have no recourse but to set our rates to recover our costs. BPA does not receive subsidies from taxpayers. We must wholly cover our costs with revenues we receive from sales of power and transmission. We are obligated to repay, with interest, all capital investments that have been made by the federal government in the facilities that are part of the Northwest's federal power system. Already, we have drawn on our financial reserves heavily this winter, and more of the same still may be ahead of us.

Some have suggested that we can simply fail to pay one of our largest creditors--the U.S. Treasury--rather than declare power emergencies or raise rates sharply. While there is no absolute guarantee we will make our full Treasury payment this October, I believe we should use all management tools available to do so. Our ability to pay our debt in full

> and on time is the best protection the Northwest has to preserve the benefits of the Columbia River hydropower system for the region. There are interests outside the region that want to see the benefits of this system directed toward other purposes. They could take great political advantage of the opportunity that would be presented if BPA did not cover its costs. One consequence could be the loss of cost-based rates for power from the federal system. We have seen how exorbitant market rates can be. If that were to happen, the region would be looking at far higher rate increases than we are now facing.
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> So, in closing, let me underscore the message. We are on a trajectory that poses grave consequences for the Pacific Northwest, primarily due to extraordinary conditions beyond our control--extremely low water, an extremely tight power supply and extremely high wholesale power prices. We believe the only alternative to a huge rate hike is to reduce our exposure to the market in the first two years of the next five-year rate period by reducing the Subscription demand on BPA. It will take major contributions from all our customers if we are to prevent a triple digit rate increase. And, we will need to make these very difficult decisions very quickly.
>
> Finally, we believe this proposal, while not an easy one to achieve, fairly balances the sacrifices the region needs and does not unfairly hit one customer group or one state over others. I know putting these proposals into place will be tough, but I believe the consequences of not taking this path will even be tougher.

Thus, the Administrator asked the regional IOUs to contribute to the mitigation of BPA's potentially difficult rate increases. The Administrator's reasoning regarding Puget's Amended Settlement Agreement, which helps to address this concern, is addressed below.

PUGET'S AMENDED SETTLEMENT AGREEMENT

The Northwest Power Act establishes a Residential Exchange Program to provide benefits to residential and small farm consumers of Pacific Northwest utilities. Also, BPA implements the REP through the offer, when requested, of a Residential Purchase and Sale Agreement. On October 31, 2000, BPA and Puget entered into Contract No. 01PB-12162 (the "Settlement Agreement"), for the purpose of settling the their dispute over implementation of rights and obligations for the REP under the Northwest Power Act, and such Settlement Agreement provides, among other things, for BPA to provide Puget with Firm Power and Monetary Benefits to settle the REP. The term of the Settlement Agreement continues through September 30, 2006.

Since the execution of the Settlement Agreement, BPA and Puget have agreed that BPA will, rather than deliver Firm Power to Puget for the first 5 years of the Settlement Agreement, make cash payments to Puget during the period that begins October 1, 2001, and ends on September 30, 2006. BPA plans to use the Firm Power not sold to Puget to meet deficits in resources necessary to meet loads of publicly-owned and cooperative customers in its firm load obligations in the Pacific Northwest. BPA and Puget have also agreed to extend the term of the settlement under the Amended Settlement Agreement (Agreement) through the period from October 1, 2006, through September 30, 2011, on the same terms and conditions as are in the corresponding Residential Exchange Settlement Agreements and Firm Power Block Sales Agreements for other investor-owned utilities for such period.

BPA and Puget acknowledge that issues have been raised regarding the Settlement Agreement and they wish to affirm their intent to settle their obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act. BPA and Puget desire to enter into the Amended Settlement Agreement in order to supersede the Settlement Agreement in its entirety for the purpose of replacing the delivery of Firm Power by BPA to Puget with cash payments during the period that begins October 1, 2001, and ends on September 30, 2006; extending the term of the Settlement Agreement until September 30, 2011; and affirming their intent to settle their rights and obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act.

A number of issues arose during the negotiation of the Amended Settlement Agreement. The reasoning supporting the resolution of these issues is addressed below.

1. TERM

As noted previously, the intent of the Amended Settlement Agreement is to provide Puget cash payments in lieu of firm power deliveries under the Settlement Agreement for the first five years of that agreement. Therefore, the Amended Settlement Agreement takes effect on the date signed by the Parties. Performance of the Agreement begins on July 1, 2001, and continues through September 30, 2011, unless terminated prior to that date.

2. DEFINITIONS

The Parties agreed to certain defined terms in order to implement the Agreement. These terms are generally consistent with the defined terms in the Settlement Agreement.

3. EFFECT ON EXISTING AGREEMENTS AND SECTION 5(c) OBLIGATIONS

(a) Existing Settlement Agreement

BPA and Puget determined that the most efficient way to effect the shift from power to cash benefits for the first five-year period and to extend the term of the Agreement to ten years was to develop a new amended agreement. Therefore, the Amended Settlement Agreement replaces and supersedes in its entirety the Settlement Agreement, including the Firm Power Block Sales Agreement, executed by BPA and Puget (RL only), Contract No. 12168.

(b) Satisfaction of Section 5(c) Obligations

The purpose of the Agreement is for BPA to provide Puget with power and financial benefits in order to effect full and complete satisfaction of all of its obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act. Section 3(b) notes that BPA will provide to Puget: (1) cash payments for the period that begins July 1, 2001, and ends on September 30, 2001; (2) beginning October 1, 2001, through September 30, 2006, cash payments and Monetary Benefits; and (3) beginning October 1, 2006, through September 30, 2011, Firm Power or Monetary Benefit payments, or both. In turn, Puget agrees that the cash payments, Firm Power or Monetary Benefits, or both, provided under the Agreement satisfy all of BPA's obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act.

(c) Invalidity

BPA and Puget have worked diligently to ensure that the Settlement Agreement and this Agreement are legally sound and will be effective for their respective terms. Some BPA customers, however, have been extremely litigious regarding the implementation of BPA's Power Subscription Strategy. Given this environment, an invalidity provision addresses the possibility, hopefully slight, that a challenge might render the agreements invalid. Section 3(c) of the Agreement provides that in the event the United States Court of Appeals for the Ninth Circuit finally determines that the Agreement (or specified sections of the Agreement) is unlawful, void, or unenforceable, then the satisfaction of section 5(c) rights and responsibilities noted previously is no longer valid. BPA and Puget also agree that the cash payments, the Firm Power, and the Monetary Benefits provided prior to the court's final determination will be retained by Puget, and that the satisfaction of BPA's obligations to Puget under section 5(c) of the Northwest Power Act prior to such final determination will be preserved, to the maximum extent permitted by law. This would avoid a difficult and complicated process of determining a new agreement and retroactively implementing changes to the benefits for that period. Additional difficulties would lie in the ability of Puget and the state public utility commissions to implement such changes without creating potential economic harm to consumers. If cash payments, Firm Power and Monetary Benefits are not retained by Puget, then the satisfaction of BPA's obligations does not occur. These provisions are also severable in the event that there is a determination that any other provision of this Agreement (or the exhibits) is unlawful, void, or unenforceable.

(d) Negotiation of New Agreement if the Agreement is Held Invalid

Section 3(d) of the Agreement provides that if the Agreement (or payment under specified sections of the Agreement) were finally determined to be unlawful, void, or unenforceable, then both BPA and Puget agree to negotiate in good faith a new, mutually acceptable agreement that would, until the end of its term, be in satisfaction of BPA's obligations under or arising out of section 5(c) of the Northwest Power Act. The term of such new agreement would continue for the remaining term of the Agreement.

(e) Payments by BPA for July 1, 2001, through September 30, 2001

There was a three month gap between the end of the previous RPSA settlements, June 30, 2001, and the beginning of the new Subscription contract period, October 1, 2001. BPA and Puget previously negotiated fixed settlement payments for this three month period. These payments are reaffirmed here.

4. SETTLEMENT BENEFITS

BPA has negotiated cash payments to Puget for two different time periods. During the first year of the Agreement, from October 1, 2001, through September 30, 2002, BPA has negotiated a cash payment based on two different principles. Under the first principle, Puget has agreed to reduce BPA's obligation to deliver firm power by 10% (or 37 annual aMW) in exchange for a cash payment of $20 per MWh. This payment is substantially below the market value for a one-year purchase of firm power from the wholesale market and represents Puget's contribution to the regional effort to reduce BPA's wholesale rate increase. This reduced payment is contingent on BPA's other customers contributing to the regional effort as further described below in the section on load reduction contingency. If the contingencies in the load reduction provisions occur, this payment will increase to $38 per MWh.

Under the second principle, the balance of the first year payment for the remaining 331 annual aMW of firm power and the payments for the remaining four years for 368 annual aMW is based on a cash payment of either $38 or $45.49 per MWh depending on the results of settlement discussions among Puget and BPA's public agency customers. This payment reflects the value to BPA of avoiding a purchase of wholesale firm power for a five-year period.

During the one-month period of negotiation of this Agreement, the market price for five year purchases of firm power has varied between $100 per MWh and $65 per MWh, reflecting the current high and volatile market prices. If BPA had supplied firm power to Puget, BPA forecasts that the rate paid by Puget would average between $25-$38 per MWh depending on market prices and assumptions made about BPA's success in reducing its wholesale rates through the current regional effort. BPA believes that the payment to Puget is a reasonable payment by BPA to avoid a purchase in the wholesale market and a subsequent sale by BPA to Puget.

Monetary Benefits are continuing to be provided to Puget during the first five-year period in the same manner as such benefits were previously provided in the Settlement Agreement between BPA and Puget.

BPA and Puget are also extending the Agreement for the period from September 30, 2006, through September 30, 2011. Previously, Puget was the only IOU to have chosen a five-year settlement term instead of a 10-year settlement term. During the negotiations to provide Puget cash benefits instead of Firm Power in order to help reduce BPA's proposed wholesale power rates, BPA and Puget also reviewed the term of the Agreement. BPA and Puget believed it was appropriate to provide Puget the same term of the Agreement that other IOUs have taken in the Settlement Agreements. The benefits provided to Puget for the second five-year period may be provided in Firm Power, Monetary Benefits, or both. These benefits are provided under the same terms and conditions that benefits are provided to the other IOUs for the October 1, 2006, through September 30, 2011, contract period. These benefits are discussed in greater detail in the "Residential Exchange Program Settlement Agreements with Investor-Owned Utilities, Administrator's Record of Decision," October 2000.

(a) Total Benefits

(1) October 1, 2001, through September 30, 2006

Section 4(a)(1) of the Agreement provides that BPA will provide Puget a total benefit comprised of cash payments and Monetary Benefits. Monetary Benefits are established in the same manner and amount as in Puget's original Settlement Agreement.

(2) October 1, 2006, through September 30, 2011

Section 4(a)(2) of the Agreement provides that BPA will provide Puget a total benefit comprised of Firm Power and Monetary Benefits, both of which are expressed in annual aMW. This total benefit is 648 aMW. These benefits are the amount BPA originally offered Puget under its Settlement Agreement. *See* Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision.

(b) Cash Payments and Firm Power Sale Portion of Total Benefits

(1) Cash Payments

Section 4(b) of the Agreement provides that BPA will make specified monthly cash payments to Puget as described above.

(A) October 1, 2001, through September 30, 2002

During the period that begins October 1, 2001, and continues through September 30, 2002, BPA will pay Puget monthly amounts of $9,722,140. However, if one or more load reduction contingency provisions in section 4(b)(1)(D) have occurred, then the total monthly payment is increased to $10,208,320.

(B) October 1, 2002, through September 30, 2006

During the period that begins October 1, 2002, and continues through September 30, 2006, BPA will pay Puget monthly amounts equal to $12,671,749. This Base Payment amount (which is $12,706,466 during a leap year) is the monthly amount subject to reduction by the Reduction of Risk Discount. A number of BPA's customers have filed legal challenges of BPA's Settlement Agreements with investor-owned utilities. If, by December 1, 2001: (i) Puget, after the date of execution of this Agreement, enters into a settlement agreement with one or more of BPA's publicly-owned utility and cooperative customers (the sufficiency of such group to be solely determined by Puget) waiving and dismissing legal challenges to this Agreement; or (ii) if Puget has entered into a Settlement Agreement described in (i) above and fails to dismiss its legal challenges, if any, to: (a) the RPSA Record of Decision (ROD); (b) the Power Subscription Strategy RODs, including the Residential Exchange Program Settlement ROD; and (c) the application of the 7(b)(2) surcharge to BPA's WP-02 rates; or (iii) legislation having the effect of the legislation described in Exhibit C is enacted prior to December 1, 2001, then the Base Payment is reduced by the Reduction of Risk Discount to the Net Payment amount of $10,208,320 ($10,236,288 during a leap year).

(C) Cash Payment Adjustments Due to Application of Safety Net Cost Recovery Adjustment Clause (SN CRAC) and Dividend Distribution Clause (DDC) to BPA Firm Power Sales

BPA has negotiated one exception to the cash payment it makes to Puget under this Agreement. BPA's wholesale power rates include an SN CRAC. The SN CRAC is designed to ensure that BPA can cover its costs as soon as possible if BPA fails to meet one of its Treasury payments. If BPA is in a situation where it must impose the SN CRAC under its wholesale power rates, BPA will reduce its monthly payments to Puget under this Agreement. BPA's monthly payments would be reduced in the same amount as the increase in rates to BPA's preference customers under the SN CRAC for the amount of firm power that BPA has converted to cash payments under the Agreement. This provision ensures that Puget's residential and small farm customers share in the resolution of any emergency that threatens BPA's ability to recover its costs.

BPA's wholesale rates also include a DDC. The DDC is designed to return money to BPA's wholesale power customers if market and other conditions result in BPA's cash reserves reaching certain levels. BPA has agreed that it will make an offsetting adjustment to Puget's monthly payments if BPA has made payments to its firm power customers under the DDC. These increased payments are only made after DDC payments made to firm power customers and are limited to the amount of any reduction in payments due to imposition of the SN CRAC.

(i) Adjustment to Cash Payments Resulting from SN CRAC and SN CRAC Balancing Account

This section of the Agreement calculates the reduction in the monthly payment to Puget under the Agreement in the event that BPA imposes an SN CRAC on its firm power customers. BPA records the amount of any such reductions in an SN CRAC Account.

(ii) DDC Balancing Account

This section determines if BPA has made DDC payments to its firm power customers. BPA records the amount it would have paid a preference customer for 331 aMW of power in Contract Year 2002 and 368 aMW in each year of Contract Years 2003-2006. BPA records such amount in a DDC Account.

(iii) Adjustment to Cash Payments Resulting from Amounts in SN CRAC Account and DDC Account

There are two situations where BPA increases the monthly payment to Puget to reflect reduced payments from imposition of an SN CRAC. The first situation occurs when BPA has imposed an SN CRAC and then makes a DDC payment at a later date. BPA has agreed that it will increase the cash payment under the Agreement within nine months of the first DDC payment. The increased payments are designed to return any reduction in payments recorded in the SN CRAC account up to the amounts recorded in the DDC Account.

The second situation occurs when BPA imposes an SN CRAC after BPA has made DDC payments at an earlier date. BPA has agreed that it will increase the cash payment under this Agreement within nine months of the SN CRAC reduction. The increased payments are designed to return any reduction in payments recorded in the SN CRAC Account up to the amounts recorded in the DDC Account.

(D) Load Reduction Contingency

When BPA proposed that its customers all contribute to BPA's rate reduction efforts, a number of customers and other interested stakeholders requested that BPA include a provision that ensured that any single customer would not be the only customer modifying its contract to reduce its obligation on BPA. BPA agreed to include a load reduction contingency provision that operated to terminate the customer's obligation to BPA if certain contingencies occurred. BPA has offered to include this provision in all of its rate reduction contracts where customers are taking actions that are valued below their market value. Under the Financial Settlement Agreement, BPA's payment to Puget will increase from $20 to $38 per MWh if any of the contingencies occur on the effective date for the particular contingency. These contingency provisions only apply to payments during the period from October 1, 2001, until September 30, 2002. Any contingencies that are effective after that date will have no effect on payments to Puget.

The first contingency is whether BPA adopts the proposed rate case settlement entered into by the Joint Customer Group and BPA staff. If the Administrator elects to not adopt that settlement in his final decisions in Docket No. WP-02, the load reduction contingency occurs and the payments to Puget will increase effective October 1, 2001. Under such settlement proposal, BPA would implement a Load Based Cost Recovery Adjustment Clause (LB CRAC) that assumes that BPA will purchase from the wholesale market any remaining amounts of power needed to augment BPA's system to serve its Subscription obligations.

The second contingency is whether BPA achieves a sufficient amount of rate reduction agreements with its public agency, investor-owned utility and direct service industrial customers during the first six month period of the LB CRAC calculation. The second contingency measures the amount of purchases BPA makes from the market in the LB CRAC calculation excluding purchases from BPA's public agency, investor-owned utility and direct service industrial customers during the period from April 10, 2001, through the calculation of the LB CRAC in late June. If BPA does not achieve approximately 1450 aMW over the initial six month period in reductions of market purchases, the load reduction contingency occurs and payments to Puget will increase effective on October 1. This provision assures any individual customer that they are not the only customer participating.

The third contingency is whether BPA achieves a sufficient amount of rate reduction agreements with its public agency, investor-owned utility and direct service industrial customers during the second six-month period of the LB CRAC calculation. The third contingency measures the amount of purchases BPA makes from the market in the LB CRAC calculation excluding purchases from BPA's public agency, investor-owned utility and direct service industrial customers during the period from April 10, 2001, through the calculation of the LB CRAC in late June and extensions of purchases with such customers entered into prior to April 10, 2001. If BPA does not achieve approximately 1250 aMW over the second six month period in reductions of market purchases, the load reduction contingency occurs and payments to Puget will increase effective on April 1. This provision assures any individual customer that they are not the only customer participating during this period.

The fourth contingency measures the end of the load reduction emergency by examining the amount of direct service industrial load BPA forecasts to serve in its calculation of the LB CRAC. If the forecast amount of direct service industrial load exceeds 400 aMW per month over the six month period of a LB CRAC calculation, the load reduction contingency occurs and payments to Puget will increase at the start of the six month period included in the calculation of the LB CRAC.

The fifth contingency measures the end of the load reduction emergency by examining the actual amount of direct service industrial load served by BPA. Once BPA starts serving more than 400 aMW per month during any six month period, the load reduction contingency occurs and payments to Puget will increase at the start of the month following the determination.

(E) No Other Adjustments to Cash Payments

Section 4(b)(1)(E) of the Agreement clarifies that except as provided in specified subsections, there are no other adjustments to the cash payment amounts under the Agreement.

(2) October 1, 2006, through September 30, 2011

Subject to the terms of the Agreement, BPA will, no later than October 1, 2005, notify Puget in writing of the amount of Firm Power in annual aMW that will be provided to Puget during the period that begins October 1, 2006, and ends on September 30, 2011. The terms and conditions for this sale will also be as provided for in the Firm Power Block Power Sales Agreement, and that agreement will be amended by the BPA and Puget to reflect the amount of Firm Power to be sold during such period. BPA will not offer an amount of Firm Power that exceeds Puget's net requirement at the time of the notice issued by BPA. Prior to issuing such notice, BPA will consult with Puget regarding its desire for Firm Power or Monetary Benefits.

If Puget does not purchase any Firm Power during the period from October 1, 2001, through September 30, 2006, Puget will establish an initial net requirement under Exhibit C of the Firm Power Block Power Sales Agreement by August 1, 2005, for Contract Year 2007. Puget will execute a contract including the terms and conditions of the Firm Power Block Power Sales Agreement, and the information provided on net requirements by January 1, 2006, if BPA notifies Puget that a portion of its benefits will be provided as Firm Power.

If the RL Rate calculated at 100 percent annual load factor for the period from October 1, 2006, through September 30, 2011, exceeds the Lowest PF Rate for the same 100 percent annual load factor during such period, Puget may, by written notice to BPA within 30 days after BPA published its power rate case ROD, notify BPA that it will convert its entire Firm Power purchase under the Firm Power Block Power Sales Agreement to Monetary Benefits for the remaining term of the Agreement.

(c) Monetary Benefit Portion of Total Benefits

(1) Amount of Monetary Benefit

(A) October 1, 2001, through September 30, 2006

BPA will provide 332 annual aMW to Puget in Monetary Benefits for the period that begins October 1, 2001, and continues through September 30, 2006. This amount is the same amount of Monetary Benefits included in Puget's original Settlement Agreement.

(B) October 1, 2006, through September 30, 2011

No later than October 1, 2005, BPA will notify Puget in writing of the amount of Monetary Benefit, expressed in annual aMW, for which payments will be made to Puget during the period from October 1, 2006, through September 30, 2011.

(2) Determination of Monetary Benefit Monthly Payment Amounts

For both the period from October 1, 2001, through September 30, 2006, and October 1, 2006, through September 30, 2011, the Monetary Benefit monthly payment amounts will be determined in accordance with a formula. The formula is the Forward Flat-Block Price Forecast established in the same BPA power rate case as that which established the RL Rate during the relevant rate period, multiplied by the RL Rate calculated at 100 percent annual load factor, multiplied by the Monetary Benefit amount in annual aMW, multiplied by 8,760 hours; divided by 12 months.

(3) Exception to Use of RL Rate in Sections 4(c)(2)(A) and 4(c)(2)(B)

If there is no RL Rate in effect or the RL Rate exceeds the Lowest PF Rate, then the Lowest PF Rate will replace the RL Rate in the payment formulas. Use of the Lowest PF Rate in such event will apply to Monetary Benefits provided in accordance with sections 4(b)(2)(C) and 4(c)(1).

(d) Payment Provisions

This section of the Agreement provides that BPA will pay Puget monthly cash payments, Monetary Benefits and monthly installments. These payment amounts are netted against the monthly payment amounts that Puget owes BPA for Firm Power purchases. If the monthly cash payments, Monetary Benefits and monthly installments exceed what Puget owes BPA for Firm Power, then BPA will pay Puget either on the due date of the bill under the Firm Power Sales Agreement or, if Puget is not purchasing power, within 30 days of the end of the calendar month for which cash payments and Monetary Benefits are due (Due Date). After the Due Date, a late payment charge is calculated at a prescribed rate. This section also provides that BPA will pay by electronic funds transfer using Puget's established procedures.

5. CASH PAYMENTS IF FIRM POWER NOT DELIVERED

Section 5(a) of the Agreement incorporates provisions from the Settlement Agreements regarding the conditions under which Firm Power is not delivered, and the determination of cash payments when such conditions occur. The conditions under which Firm Power is not delivered include where the amount of Firm Power purchased exceeds the utility's net requirement; where Firm Power is assigned to another entity that is not eligible for net requirement purchases; where there is an insufficiency; where there is a termination or decrement for the export of a regional resource; where Firm Power is not delivered due to a monthly purchase deficiency; and where the Block Sales Agreement is held invalid.

Section 5(b) establishes a formula for determining cash payment amounts when the conditions of section 5(a) occur. Section 5(c) provides that rather than receive payments under the default option described in section 5(b)(1), Puget may elect to offer BPA a put right for amounts of power not delivered pursuant to sections 5(a)(1) through 5(a)(4), and section 5(a)(6). Section 5(b)(2) establishes the terms of the exercise of the put right.

Section 5(b)(3) of the Agreement provides an exception to the use of the RL rate in determining cash payment amounts and implementation of the put right. If there is no RL Rate in effect or the RL Rate exceeds the Lowest PF Rate, then the Lowest PF Rate replaces the RL Rate in the formulas.

Section 5(b)(4) of the Agreement provides that if the monthly payment amount determined pursuant to the formulas is positive, then BPA pays the amount to Puget. If the amount is negative, then Puget pays the amount to BPA.

6. PASSTHROUGH OF BENEFITS

Section 5(c)(3) of the Northwest Power Act provides that the benefits of the REP are to be passed through directly to a utility's residential loads within a State. 16 U.S.C. §

839c(c)(3). Similarly, BPA and Puget have provided that the benefits from the Agreement are passed through in such a manner. Section 6(a) of the Agreement therefore provides that, except as otherwise provided in the Agreement, cash payment amounts received by Puget from BPA under the Agreement must be passed through, in full, to all residential and small farm consumers comprising Puget's Residential Load, as either (1) an adjustment in applicable retail rates; (2) monetary payments, or (3) as otherwise directed by the applicable State regulatory authority. Section 6(a) also confirms one manner in which cash benefits and Monetary Benefit amounts may be passed through to Residential Load.

Section 6(b) of the Agreement ensures that cash benefits under the Agreement must be distributed to Puget's Residential Load in a timely manner. This is accomplished by providing that the amount of benefits held by Puget will not exceed the expected receipt of monetary payments from BPA under the Agreement over the next 180 days. If the annual monetary payment is less than $600,000, section 6(b) permits Puget to distribute benefits on a less frequent basis provided that distributions are made at least once each contract year. Section 6(b) also permits the distribution of monetary payments in advance of its receipt of such payments from BPA in an amount not to exceed the expected receipt of monetary payments from BPA under the Agreement over the next 180 days.

Section 6(c) of the Agreement provides that the benefits will be passed through consistent with procedures developed by Puget's State regulatory authority(s). Cash payments under the Agreement will be identified on Puget's books of account in order that such benefits can be easily tracked. In addition, funds will be held in an interest bearing account, and will be maintained as restricted funds, unavailable for the operating or working capital needs of Puget. Also, benefits will not be pooled with other monies of Puget for short-term investment purposes. These provisions ensure that benefits will be provided only to Puget's residential and small farm consumers. The Agreement clarifies that once Puget has provided the benefits to its residential and small farm consumers by applying it as a credit on their bills, the funds are no longer restricted funds.

Section 6(d) provides that nothing in the Agreement requires that any power be delivered on an unbundled basis to residential and small farm customers of Puget or that Puget provide retail wheeling of such power.

7. AUDIT RIGHTS

Section 7 of the Agreement establishes audit rights that are virtual identical to the audit rights in the Settlement Agreement. BPA has audit rights to ensure that, even if benefits are passed through as directed by the applicable state regulatory authority, BPA can require that benefits only be passed through to eligible Residential Load. BPA retains the right to audit Puget at BPA's expense to determine whether the benefits provided to Puget under the Agreement were provided only to Puget's eligible Residential Load. BPA retains the right to take action consistent with the results of the audit to require the passthrough of benefits to eligible Residential Load. BPA's right to conduct audits of Puget with respect to a Contract Year expires 60 months after the end of the Contract Year. As long as BPA has the right to audit Puget under the Agreement, Puget will maintain all relevant records.

8. ASSIGNMENT

Section 8 of the Agreement addresses the assignment of the benefits of the Agreement. This section is virtually identical to the assignment provisions in the Settlement Agreement. This section reflects the need for flexibility in the provision of benefits to Puget's residential and small farm customers in light of the uncertainty of the energy industry regarding deregulation or other efforts that could restructure state retail electric service. These provisions are virtually identical to the assignment provisions in the Settlement Agreement. Section 8(a) requires Puget to assign benefits to BPA if a Qualified Entity serves Residential Load formerly served by Puget (unless BPA has approved an agency agreement for such Qualified Entity), or BPA has approved a state program for the passthrough of benefits by a distribution utility.

Section 8(b) of the Agreement provides that the Agreement is binding on any successors and assigns of the Parties, but that neither Party may otherwise transfer or assign this Agreement without the other Party's written consent. Such consent cannot be unreasonably withheld, provided that Puget agrees it will assign benefits under this Agreement subject to the following terms and conditions: (1) Puget will quantify an amount of Residential Load each month served by Qualified Entities that would have been eligible to receive benefits if served by Puget, and provide written notice of such amount to BPA; (2) Puget will assign to BPA during the month following such notice a share of the total benefits, whether or not Puget continues to serve such Residential Load. The Residential Load of Puget will not include Residential Load receiving benefits over a new distribution system; (3) If the passthrough of benefits is made to consumers with Puget acting as agent, then Puget will retain the cash payments assigned to BPA and use such cash payments to provide benefits to individual residential and small farm consumers.

Section 8(c) of the Agreement provides that Puget may continue to pass through benefits to individual residential and small farm consumers under this Agreement not served by Puget if (i) Puget is acting as the agent under an agreement entered into between Puget and a Qualified Entity which has been approved by Puget's applicable state regulatory authority and BPA; or (ii) BPA has approved a program developed by the applicable state regulatory authority providing for the passthrough of benefits received by Puget under the Agreement to all its residential and small farm consumers acting in its capacity as a distribution utility.

Section 8(d) of the Agreement provides that if a Qualified Entity eligible to purchase firm power under section 5(b) of the Northwest Power Act acquires all or a portion of the distribution system serving the Residential Load of Puget, Puget will assign a share of the total benefits to BPA for the remaining term of the Agreement.

9. NOT APPLICABLE

This section of the Agreement was intentionally left blank.

10. CONSERVATION AND RENEWABLES DISCOUNT

The rates contained in BPA's May Proposal include a Conservation and Renewables Discount (C&R Discount). The C&R Discount is designed to encourage the development of conservation and renewable energy resources. Section 10 of the Agreement addresses how the C&R Discount will apply to the cash benefits provided to Puget. Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules, including GRSPs, BPA will pay Puget an amount equal to the C&R Discount for 368 aMW for each Contract Year during the October 1, 2001, through September 30, 2006, period, unless Puget has notified BPA's Power Business Line (PBL) before August 1, 2001, that it will not participate in the C&R Discount. This is to ensure that Puget's residential and small farm consumers will retain the benefits they would have received if Puget had provided power benefits instead of cash benefits. Where Puget is willing to assist BPA's rate mitigation efforts by receiving cash benefits instead of power, Puget should not be penalized for such actions.

To retain the full amount of the C&R Discount, Puget must satisfy all obligations associated with the C&R Discount as specified in BPA's applicable Wholesale Power Rate Schedules, including GRSPs, and the C&R Discount implementation manual. Puget will reimburse BPA for any amount it received but for which it did not satisfy such obligations.

11. GOVERNING LAW AND DISPUTE RESOLUTION

Puget requested a dispute resolution provision in its Settlement Agreement based on litigation. Puget then requested, and BPA agreed, to modify such provision in the Amended Settlement Agreement to a dispute resolution provision based on arbitration.

Section 11 of the Agreement addresses the law governing the Agreement and the manner in which disputes under the Agreement will be resolved. In summary, the Agreement will be interpreted consistent with and governed by Federal law. Final actions subject to section 11(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. Other contract disputes or contract issues between the Parties arising out of this Agreement will be subject to binding arbitration. The Parties will make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties will continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

12. NOTICE PROVIDED TO RESIDENTIAL AND SMALL FARM CUSTOMERS

Section 12 of the Agreement provides that Puget will ensure that any entity that issues customer bills to Puget's residential and small farm consumers will provide written notice on such customer bills that their benefits are "Federal Columbia River Benefits supplied by BPA."

13. STANDARD PROVISIONS

Section 13 of the Agreement includes a number of standard contract provisions. These provisions are virtually identical to those in the Settlement Agreement. These provisions include a requirement for a written instrument to amend the Agreement; conditions governing the exchange of information and the confidentiality of such information; a provision that Agreement constitutes the entire agreement between the Parties; a provision that incorporates the exhibits into the Agreement by reference; a provision that no other person is a direct or indirect legal beneficiary of, or has any direct or indirect cause of action or claim in connection with the Agreement; and a provision providing that any waiver at any time by either Party to the Agreement of its rights under the Agreement will with respect to any default or any other matter arising in connection with this Agreement will not be considered a waiver with respect to any subsequent default or matter.

14. TERMINATION OF AGREEMENT

Section 14 of the Agreement addresses termination of the Agreement. There are three basic provisions for termination. First, if BPA does not adopt the Partial Stipulation and Settlement Agreement in the WP-02 Wholesale Power Rate proceeding, then Puget may, upon written notice to BPA prior to September 1, 2001, terminate the Agreement. This is because, absent the adoption of the Partial Stipulation and Settlement Agreement, Puget would not agree to the terms of this Agreement. Second, the Agreement is subject to Puget's determination by June 15, 2001, that the Washington Utilities and Transportation Commission (WUTC) will approve this Agreement and provide satisfactory retail rate treatment. This is because, if Puget knew that it would not receive approval of the Agreement from the WUTC, Puget would not enter the Agreement. Finally, Puget may terminate the Agreement if BPA does not use BPA's then-current rate case Forward Flat-Block Price Forecast for all estimates of the cost of purchases of flat blocks of power in its rate cases, which are made in advance of the period of delivery and which are made for the rate period established in the particular rate case that occurs between October 1, 2006, and September 30, 2011. Puget must provide written notice up to 30 days after FERC grants interim approval for BPA's wholesale power rates effective during the period occurring between October 1, 2006, and September 30, 2011. This provides Puget the ability to terminate the Agreement if BPA's then-current rate case Forward Flat-Block Price Forecast does not meet acceptable criteria and would provide, in Puget's eyes, inadequate Monetary Benefits.

15. SIGNATURES

Section 15 provides that each signatory represents that he or she is authorized to enter into this Agreement on behalf of the Party for whom he or she signs.

16. EXHIBIT A: BLOCK POWER SALES AGREEMENT

Exhibit A to the Agreement is a Block Power Sales Agreement, Contract No. 01PB-10886. The Block Power Sales Agreement is the same agreement that is attached as an exhibit to the Settlement Agreements of the other IOUs. The development of the Block Power Sales Agreement was previously addressed in BPA's "Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision," October 2000. The Amended Settlement Agreement attaches a Block Sales Agreement that includes the terms and conditions for a ten-year Block Sales Agreement. The Block Sales Agreement attached to the Settlement Agreement only provided for a five-year sale.

CONCLUSION

I have reviewed and evaluated the record compiled by BPA on the foregoing issues and terms regarding BPA's Amended Settlement Agreement with Puget Sound Energy. Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the Amended Settlement Agreement with Puget Sound Energy. The evaluations and decisions used in the development of the Amended Settlement Agreement are consistent with the environmental analysis conducted for BPA's 1998 Power Subscription Strategy, BPA's Power Subscription Strategy NEPA ROD, BPA's Business Plan EIS, and BPA's Business Plan ROD.

Issued at Portland, Oregon, this 6th day of June, 2001.

\s\ Stephen J. Wright

Acting Administrator and Chief Executive Officer

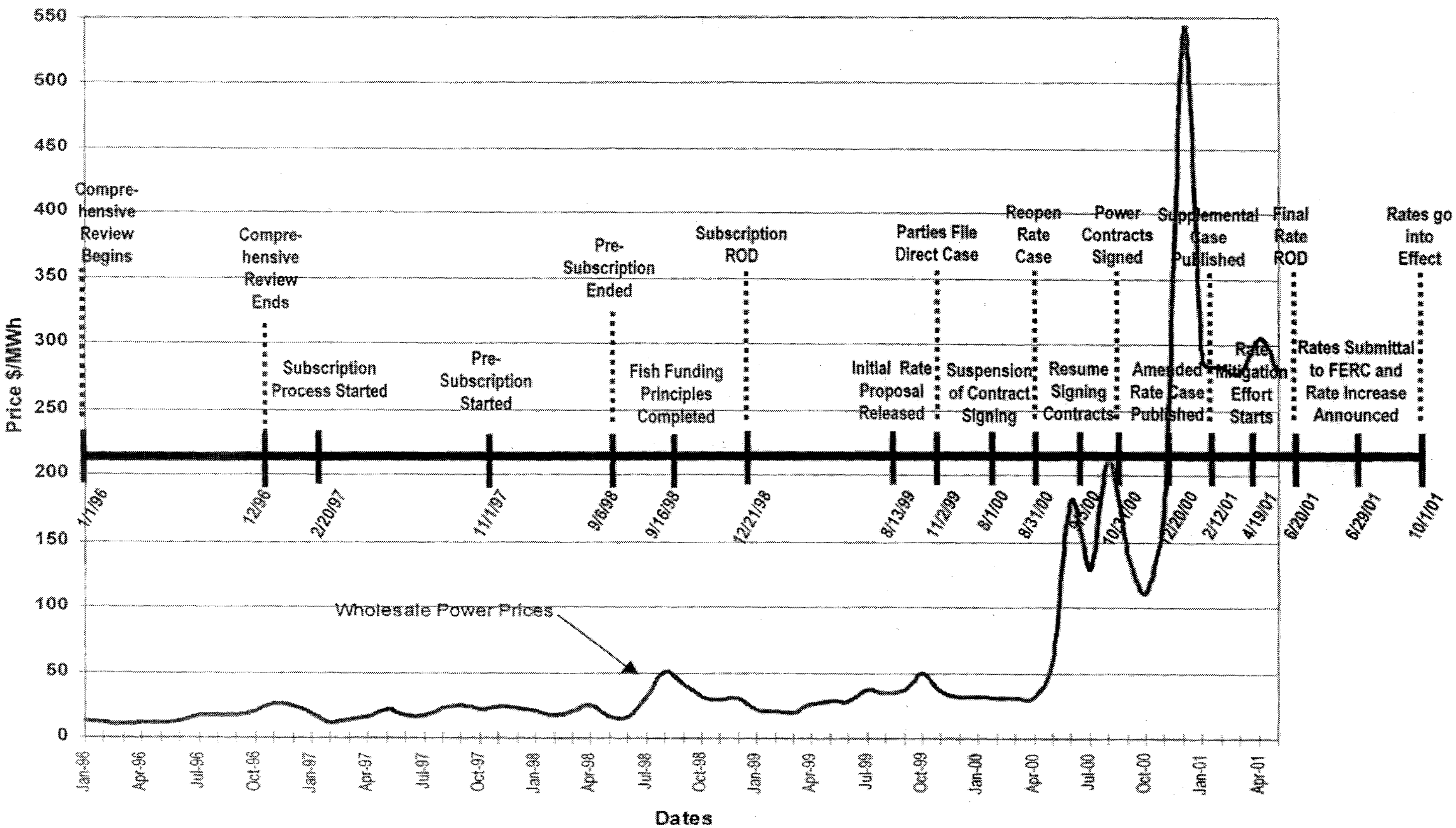
Power Rates and New Power Contracts
Briefing for Deputy Secretary

Thursday, June 14, 2001

REDACTED VERSION

Paul E. Norman
Senior Vice President
Power Business Line

Rate and Contract Timeline



Subscription and Rate Principles

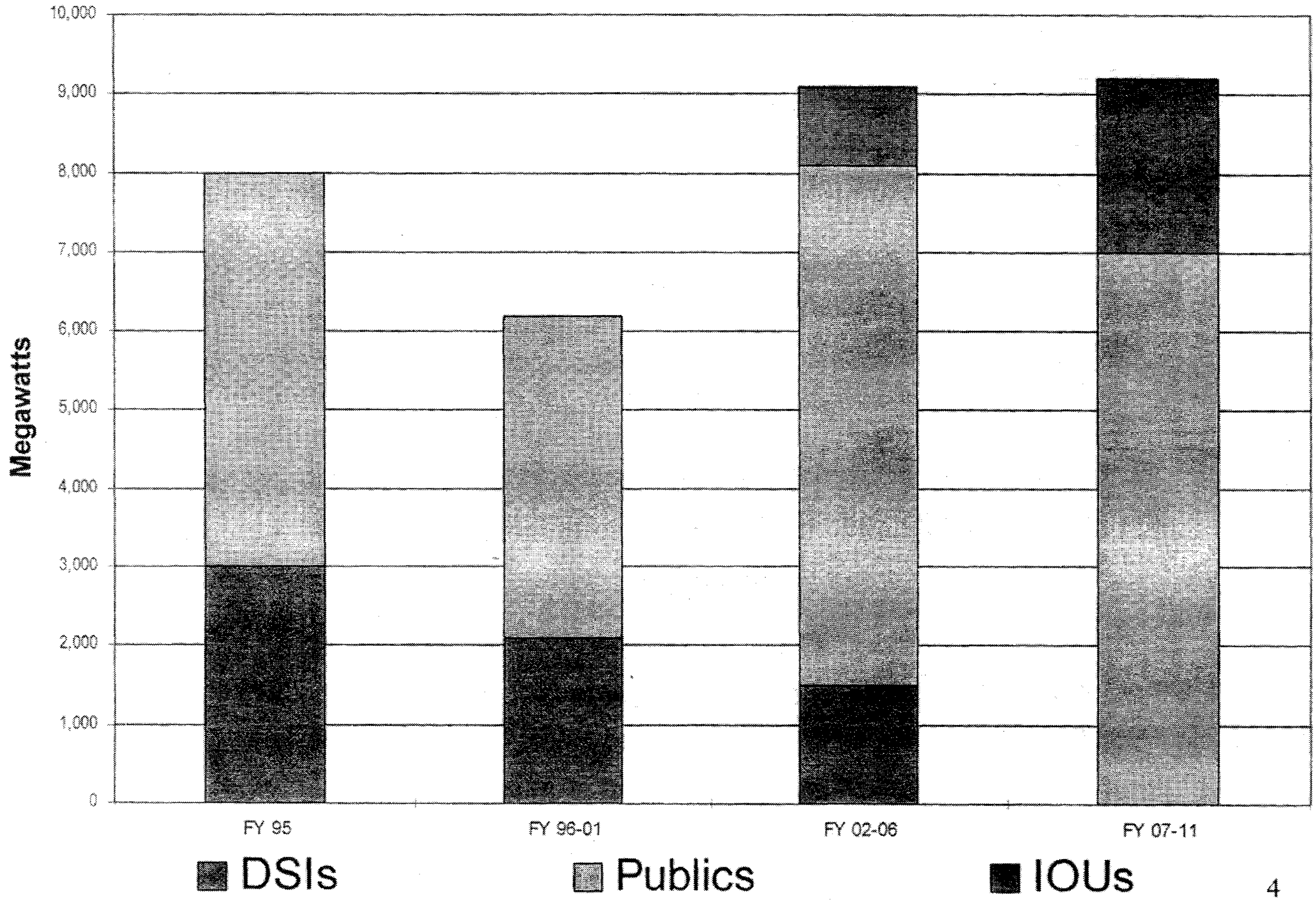
- Spread the benefits of the Federal Columbia River Power System (FCRPS) as broadly as possible, with special attention given to the residential and rural customers of the region;

- Avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions;

- Allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and

- Provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these other emerging technologies.

Contracted Rights to Federal Cost-Based Power



Risk Mitigation Tools In 2002 Rate Filing Are More Robust Than In 1996 Rate Filing

Risk Mitigation Measure	FYs 1997-2001	FYs 2002-2006
Treasury Payment Probability Target	80 percent, 5 years	85 percent, 5 years
Starting Reserves (power only)	$252 M	$429 M (expected value)
Fish Cost Contingency Fund	Yes. Access allowed when poor water. Starting balance of $325 M	Yes. Same terms of access. Starting balance (expected value) $158 M
Planned Net Revenues for Risk (average annual)	$13 M	$98 M
Other Cash Flows for Risk	$70 M	$20 M
Cost Recovery Adjustment Clause	No	Three components: **Load-Based CRAC**: applied to augmentation loads, semi-annual true-up **Financial-Based CRAC**: triggers as frequently as every year if AANR fall below reserves equivalent of $300-500 M. Uncapped in first year, capped at $100-150 M annually in other years. **Safety-Net CRAC**: triggers 7(i) process if 50% likelihood of missed payment to Treasury or other BPA creditor.
Ending Reserves Expected Value (power only)	$535 M	$1,003 M - $1147 M
Dividend Distribution Clause	No	Yes. Triggers if AANR reaches reserves equivalent of $1,200 M - $1200 M. Distribution = reserves in excess of threshold.

Treasury Payment Probability (TPP) vs. Market Prices 2002-06

Market Prices 2002	Market Prices 2006	TPP
$225/MWh	$50/MWh	88%
$148/MWh	$50/MWh	86%
$100/MWh	$50/MWh	82%

2002 Power Rate Case: Important Issues

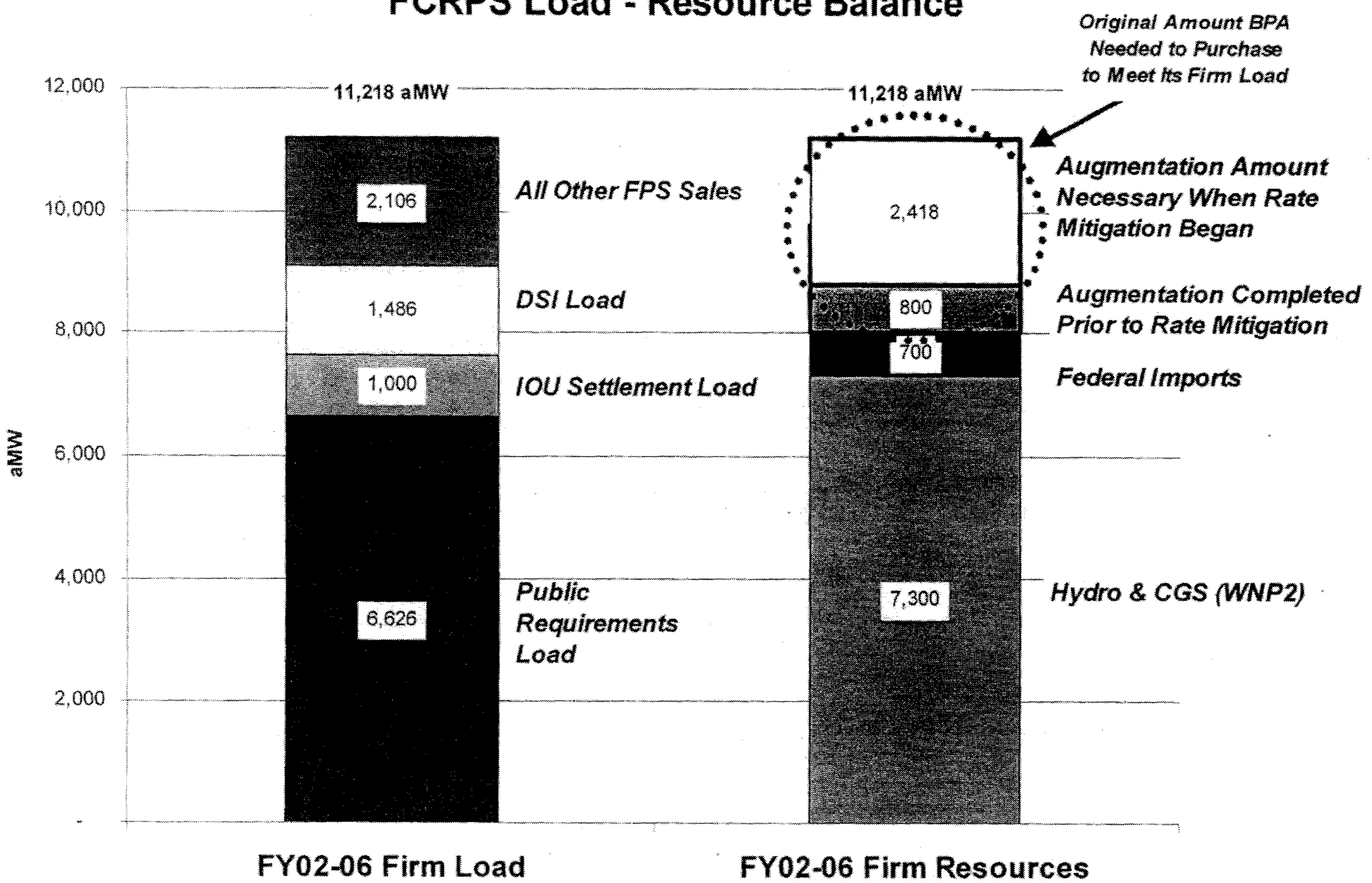
1. ***Should BPA limit sales to public preference customers*** - No. No legal basis for limitation, except for load not currently being served either by customers' own resources. But higher for NEW public utilities and annexed loads.
2. ***Should BPA make cost-based sales to the aluminum industry and other direct service industrial customers (DSIs)*** - Yes. See separate briefing package.
3. ***How to share the benefits of the system with the IOU's small farm and residential customers? -*** Settlement agreement to replace cash exchange mandated by Regional Act with combination of 1000 aMW of power at same rate as public utilities, plus cash payment.
4. ***Should BPA sell "Slices" of the Federal System? -*** Yes, in the form of the Slice product.
5. ***Should BPA implement tiered rates -*** Not in 2002, but the concept has some appeal for the future.
6. ***In the face of greatly increased cost and market risks, how does BPA still ensure all financial obligations are met? -*** Through a far more robust risk-management package than ever used before, including 6-month adjustment clauses in rates.
7. ***Whether and how to serve new public customers and newly formed Tribal entities? -*** For all but the first 150 aMW of new public and tribal utilities, a higher (near market) rate will be charged through 2006.

2002 Power Rate Case: Important Issues (cont.)

8. ***To what extent should the shape of BPA's rates reflect market prices? -*** Fully. The overall level of rates is pegged to cost, not market. But monthly and day/night rate differential mimic market.
9. ***Legal issues?***

REDACTED

FCRPS Load - Resource Balance



WHY 'RATE MITIGATION'?

Oversimplified 2002 Rate Calculation Without Rate Mitigation:

5600 aMW @ (embedded cost) $ 20/MWh

+ 1300 aMW power purchases @ $ 30/MWh

<u>+ 2400 aMW power purchases @ $200/MWh</u>

9300 aMW @ $68/MWh

So, without 'Rate Mitigation', the cost of market purchases could cause BPA rates to more than triple, from $20/MWh now to $68/MWh in 2002.

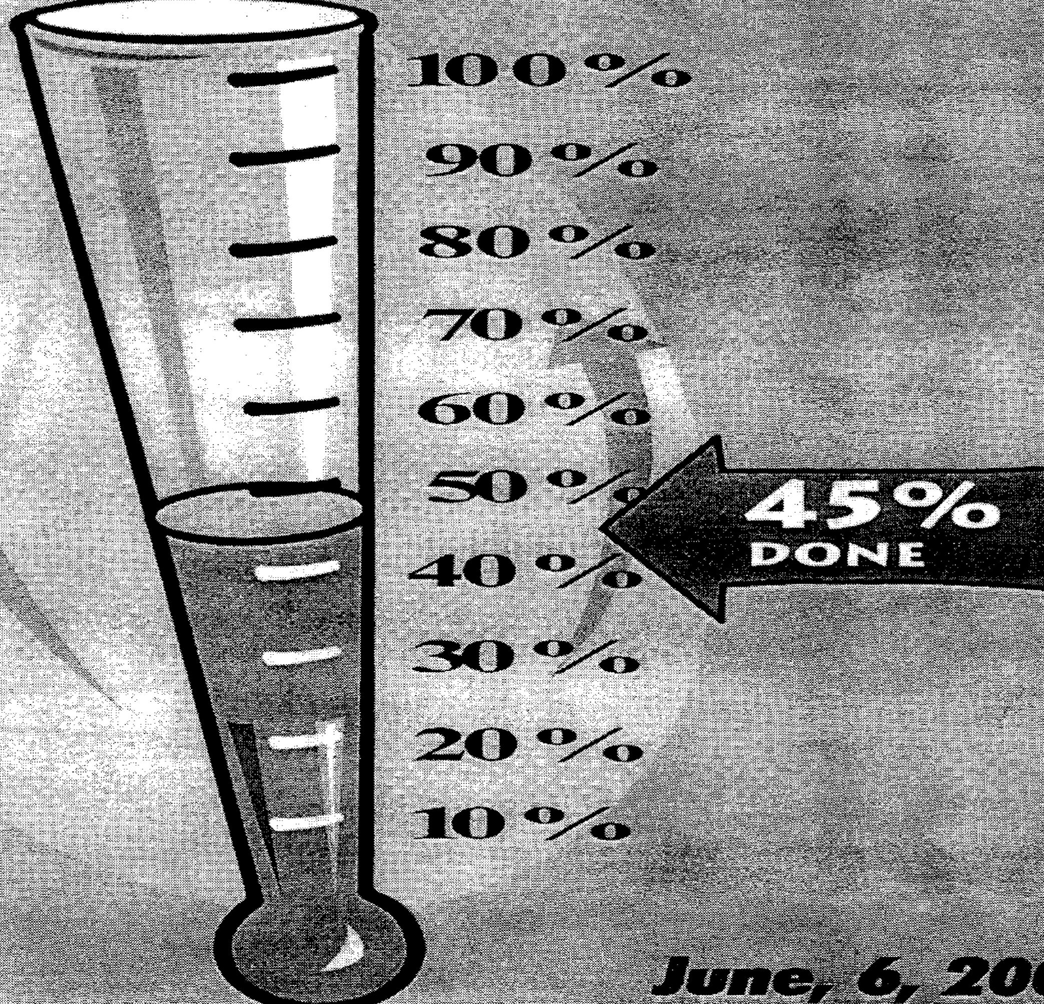
Load Reduction and Buy Back

Goal	2,400 aMW
Signed	1,219 aMW

June 6, 2001

Power Buy Back From IOU's

Goal 500 aMW
Signed 226 aMW

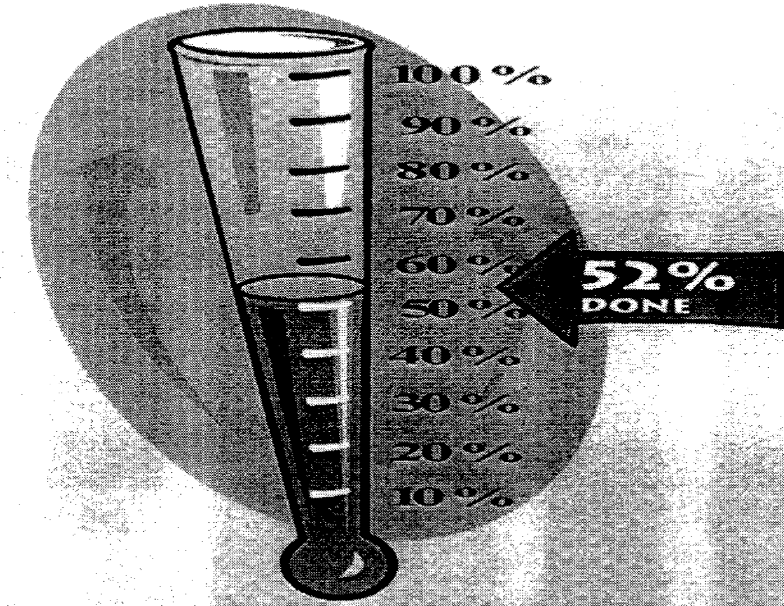


June, 6, 2001

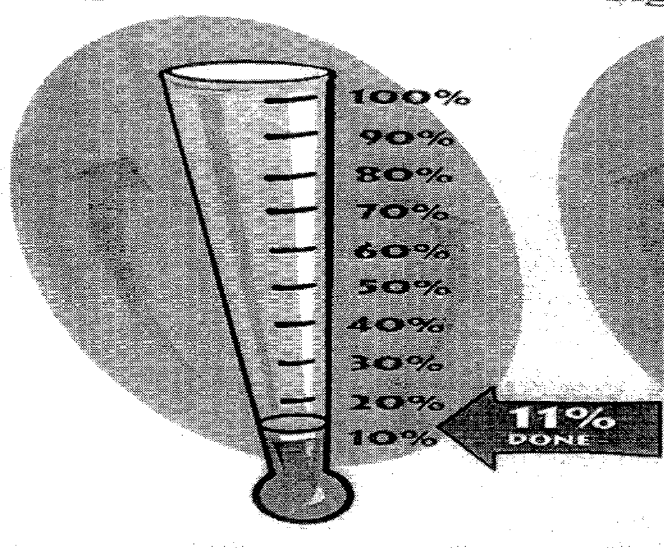
Load Reduction

Goal
1,900 aMW

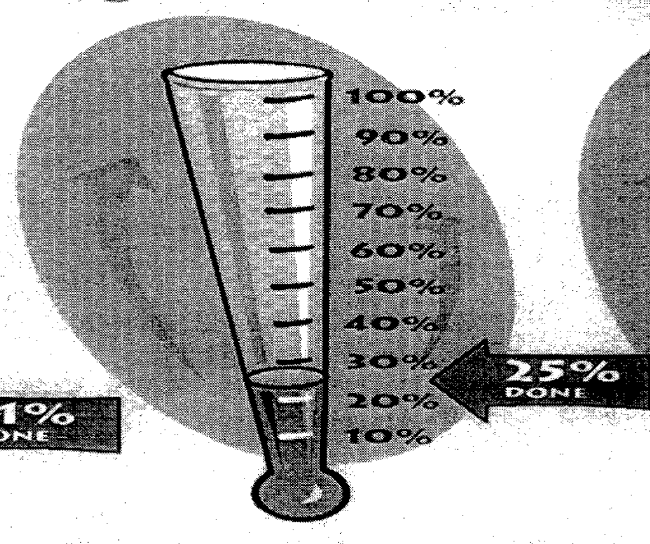
Signed
994 aMW



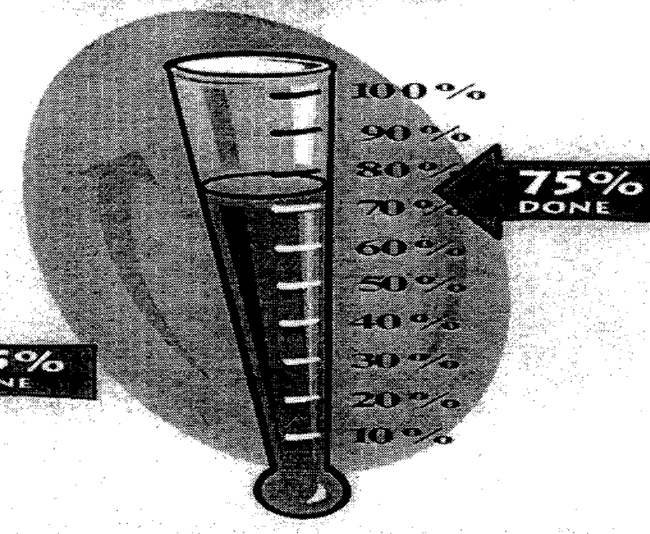
Publics
Goal 600 aMW
Signed 68 aMW



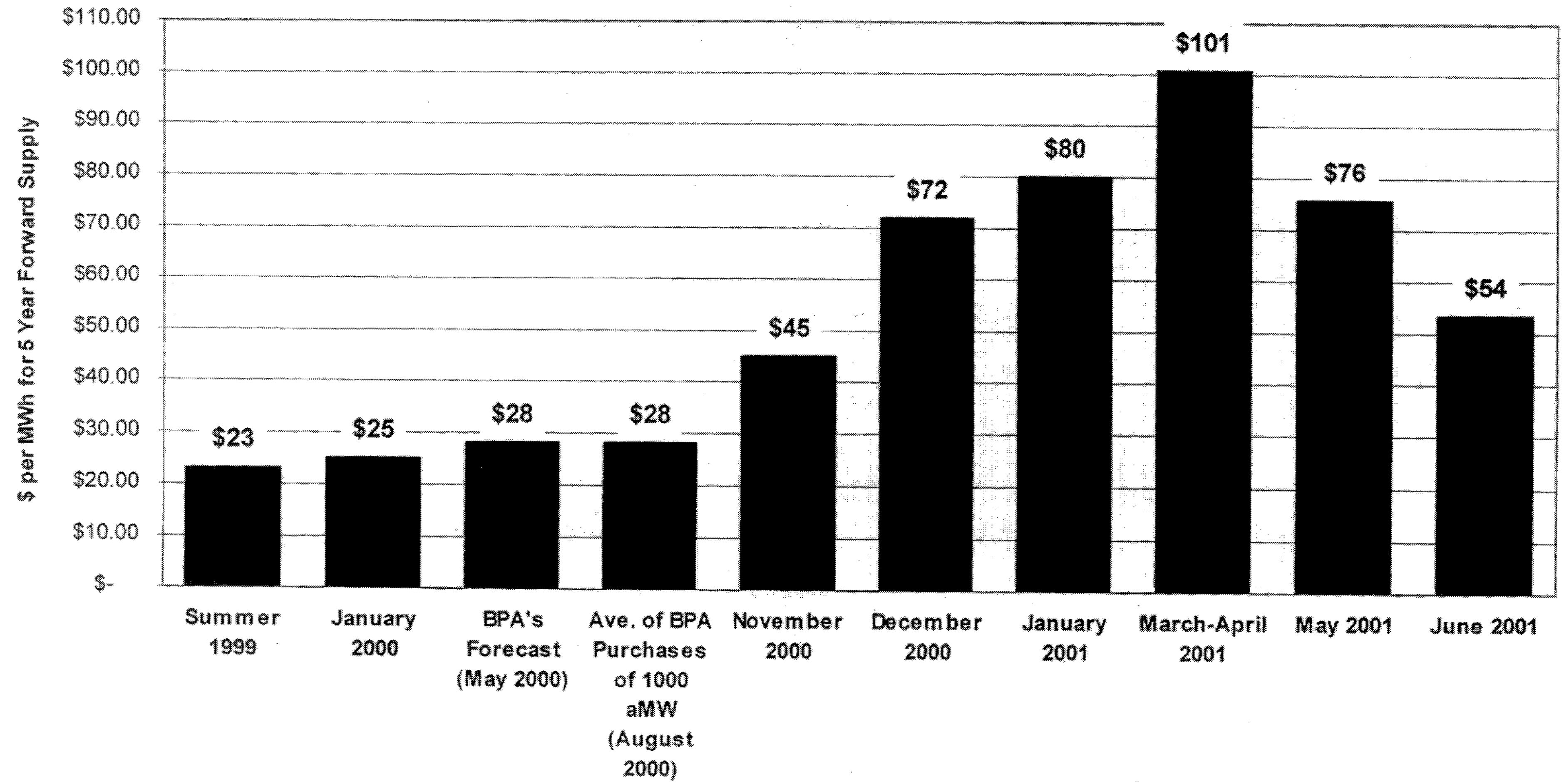
IOU's
Goal 100 aMW
Signed 25 aMW



DSI's
Goal 1,200 aMW
Signed 901 aMW



Forward Prices for FY02-FY06 Blocks of Mid-C Flat Energy



Power Rates and Contracts - Upcoming Events

- Next week - Decide treatment of DSI load
- June 22 - Deadline for signing Load Reduction Agreements
- June 29 - Announcement of October 1 Rate Levels
- Every 6 months readjust rates
- September-December Manager new contracts and rate impacts
- December: Decide McCook curtailment extension
  Decide continuation of other DSI's curtailment

Long-Term Issues

- Regionalization of Federal System
- DSI Service
- Public Preference
- Allocation vs. Augmentation
- Tiered Rates

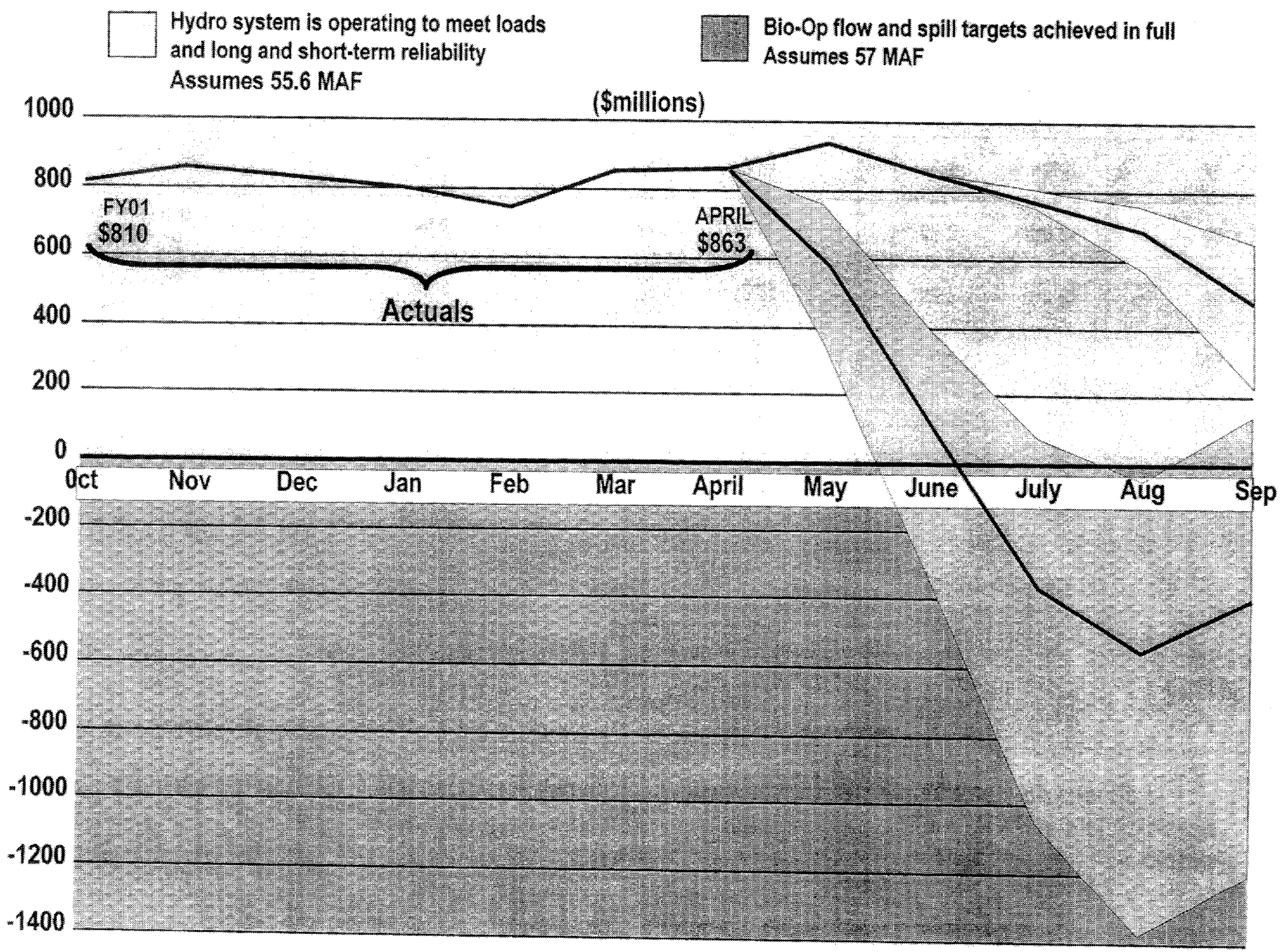
Washington DC Briefings

June 18-19

Bonneville Power Administration

TIME FRAME	ISSUES	SCHEDULE
Near Term	Managing Drought Reliability/Storage Liquidity Fish	Now through midsummer 2001
Mid Term	Rate Increase Liquidity Reliability? Fish?	June-July 2001
Long Term	Infrastructure Investment	Now through next few years

BPA Reserves Uncertainty FY 2001



Impacts on Fish Survival

Total System Survival [1] estimates (as percent of fish arriving at head of upper FCRPS pool) for Columbia River and Snake River ESUs. Reach through which survival is estimated is indicated in "ESU" column. N/c=no change

Survival estimate data from National Marine Fisheries Service, revised June 2001

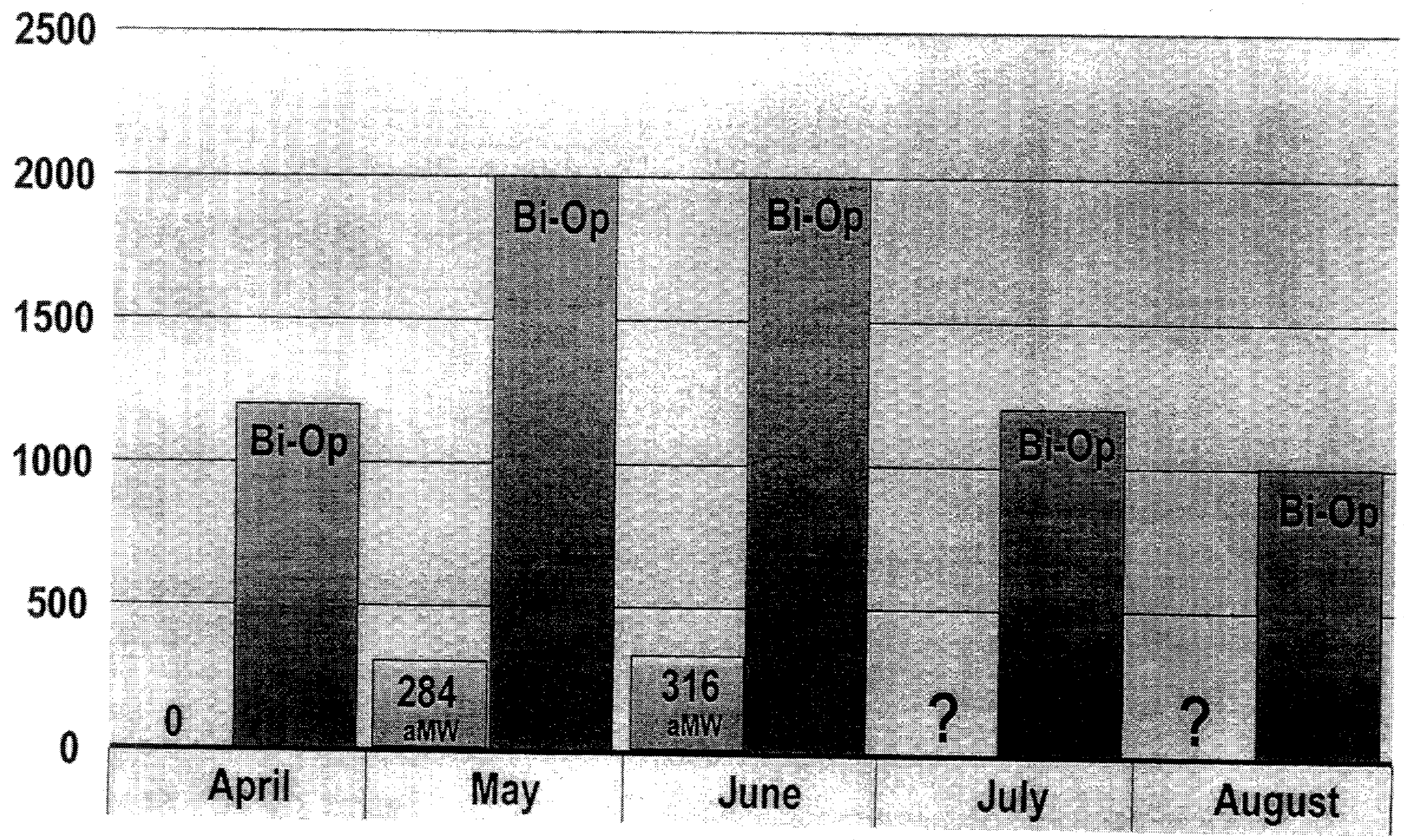
ESU	Estimated for Full Implementation of Biological Opinion, Given 2001 Water Conditions (%)	Expected Survival under No Spill Operation, Given 2001 Water Conditions (percent change from full implementation) (%)	Expected Survival under Actual 2001 Spring Spill (percent change from full implementation) (%)	Percent Transported
* SR spring/summer CH(Lower Granite-Bonneville)	55.8-64.5	55.7-64.4 (-0.2)	55.7-64.5 (-0.2)	70
* SR steelhead (Lower Granite-Bonneville)	45.5-50.8	45.5-50.8 (n/c)	45.5-50.8 (n/c)	70
* SR Fall CH (Lower Granite-Bonneville)	3.56	3.54 (-0.6)	n/a	80 [2]
UCR spring CH (McNary-Bonneville)	47.4	41.6 (-12.2)	45.7 (-3.6)	40
UCR and MCR SH (McNary-Bonneville)	54.9	47.5 (-13.5)	51.8 (-5.6)	40
MCR SH (John Day-Bonneville)	62.3	54.1 (-13.2)	58.9 (-5.5)	0
MCR SH (The Dalles-Bonneville)	76.6	66.9 (-12.7)	72.9 (-4.8)	0
LCR CH (Bonneville pool and dam)	84.4	82.0 (-2.8)	83.5 (-1.1)	0
LCR SH (Bonneville pool and dam)	86.9	84.4 (-2.9)	85.9 (-1.2)	0

*The range in survival estimates reflect the range of assumptions of delayed mortality, as indicated in the Biological Opinion

1. T[illegible]ystem Survival is the combined in-river survival plus transportation survival, incl[illegible] delayed transportation mortality. In-river survival benefits alone are higher [illegible]de uncertainty about transportation benefits.
2. P[illegible] of Snake River Fall Chinook arriving at Lower Granite Dam that are transpor[illegible]

Recommended Bi-Op Spill vs Actual Spill

(Mw-mo)

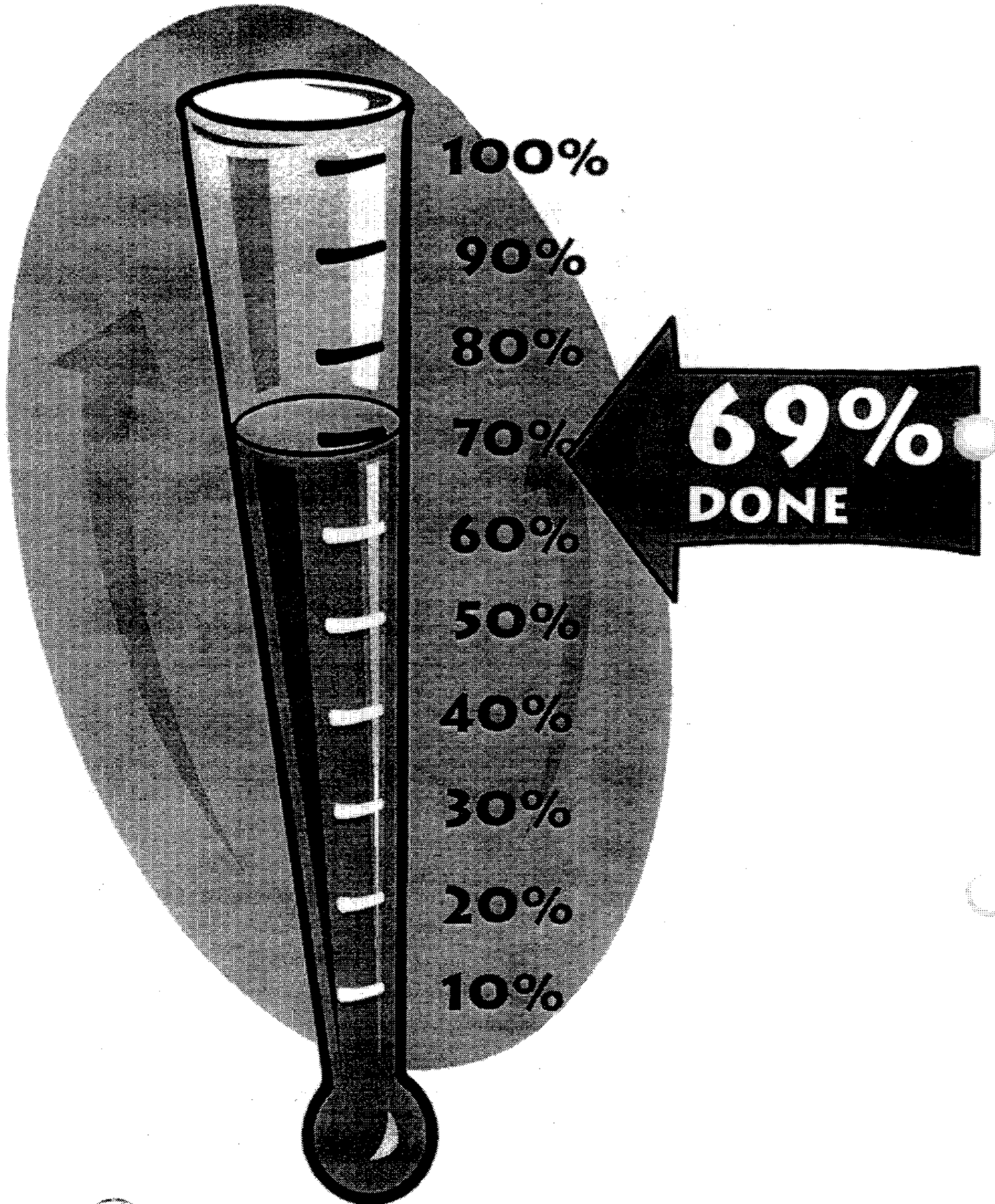


Load Reduction and Buy Back

June 14, 2001

Goal
2,400 aMW

Signed
1,666 aMW

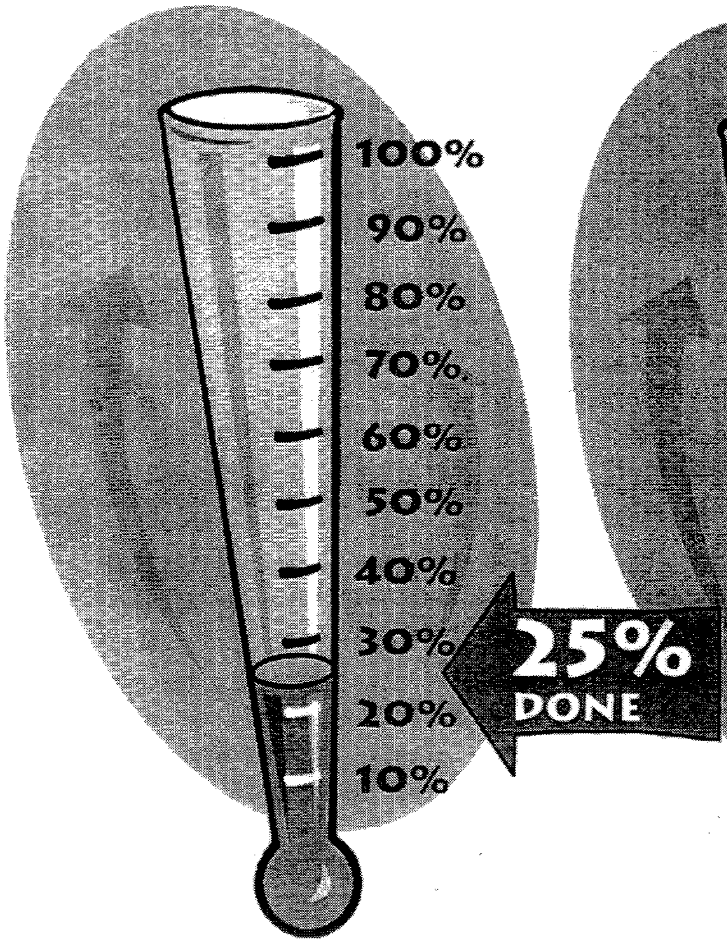


Load Reduction by Utility Group

June 14, 2001

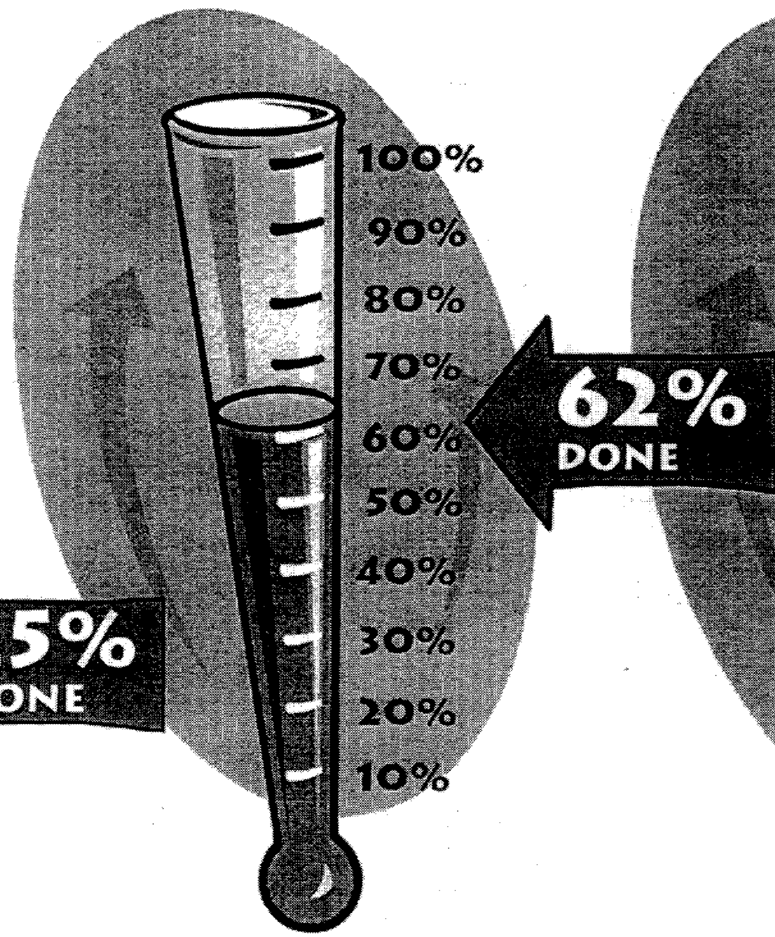
Publics

Goal 600 aMW
Signed 150 aMW



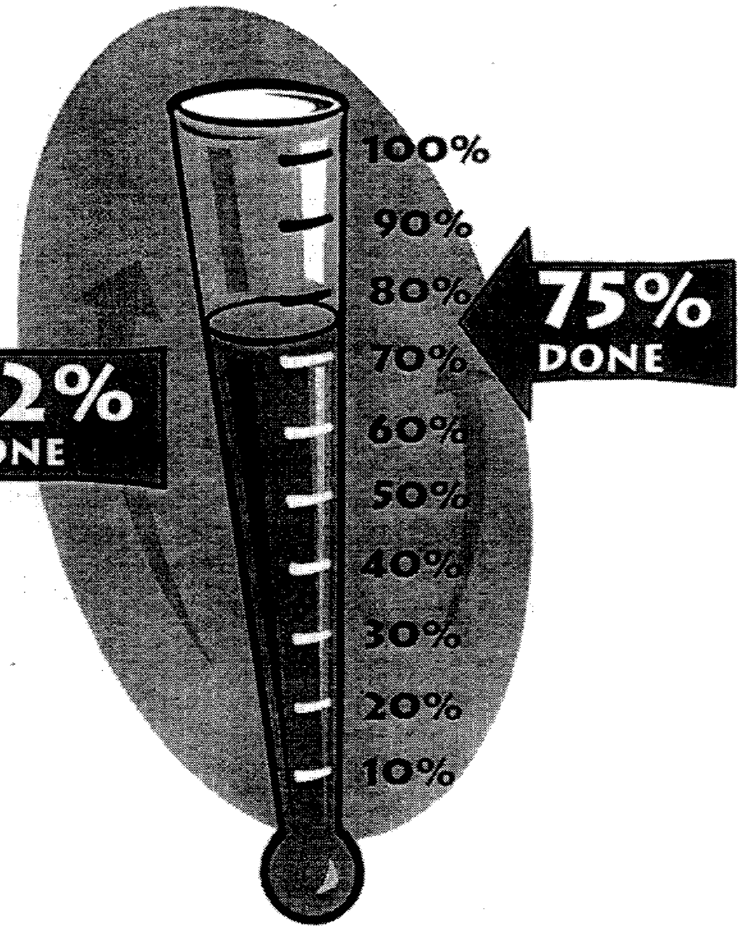
IOU's

Goal 100 aMW
Signed 62 aMW



DSI's

Goal 1,200 aMW
Signed 901 aMW



Load Reduction Heroes List

DSIs

- McCook (Longview)
- Atofina
- Oremet
- Alcoa
- Columbia Falls Aluminum Company

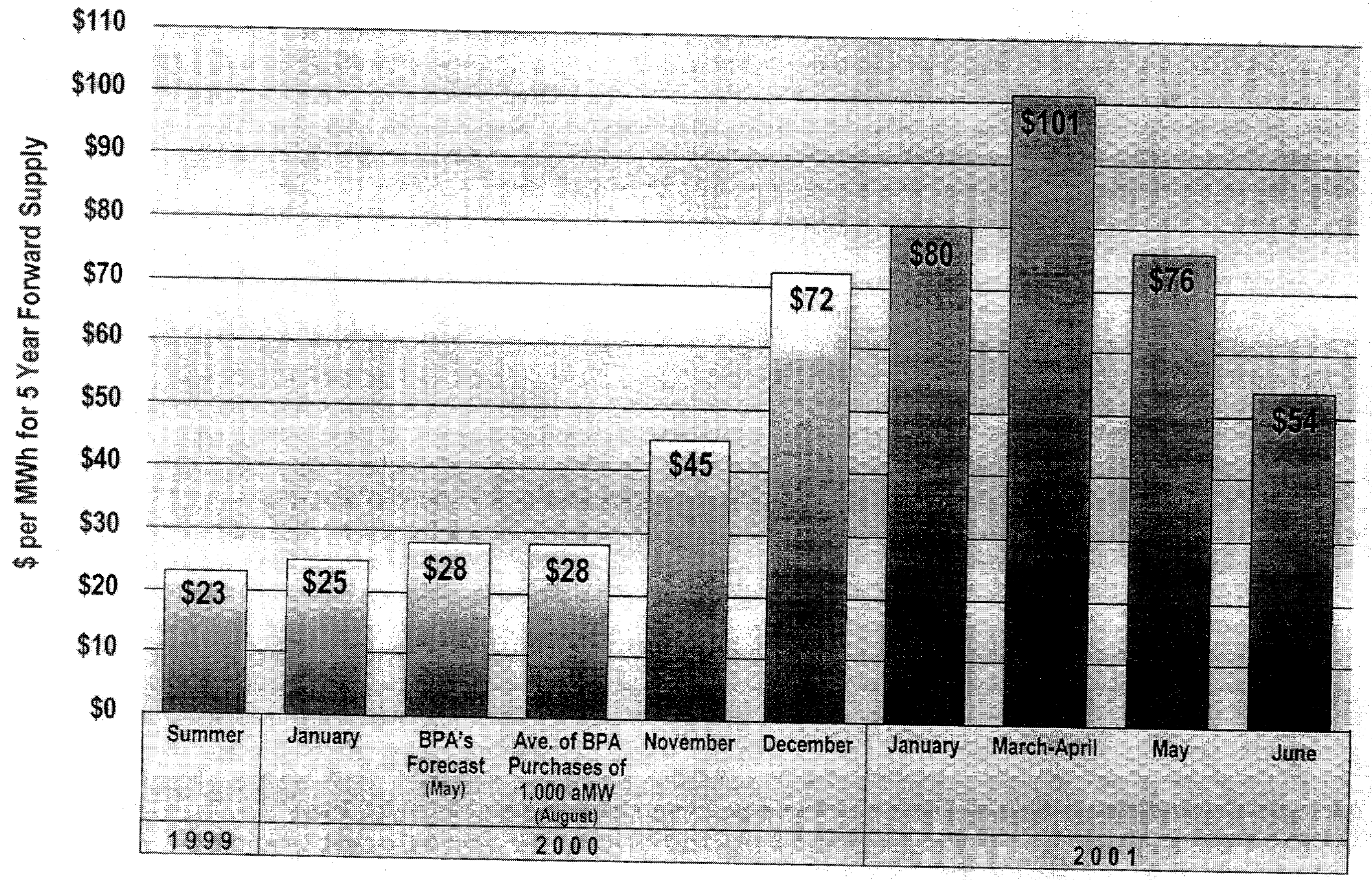
Public Utilities

- Clark Public Utilities
- Franklin PUD
- Pend Oreille PUD
- Idaho Falls Power
- Glacier Electric Cooperative
- Grays Harbor PUD
- Lakeview Light & Power
- Benton Rural Electric Association
- Seattle City light
- Whatcom PUD
- Springfield Utility Board
- Nespelem Valley Electric Coop, Inc.
- Vera Water & Power
- Benton County PUD

Investor - Owned Utilities

- PacifiCorp
- Puget Sound Energy Inc.

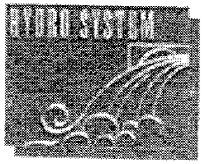
Forward Prices for FY02-FY06 Forward Blocks of Mid C Flat Energy



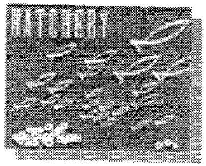
Infrastructure Investments

- Transmission
- Hydrosystem
- Conservation

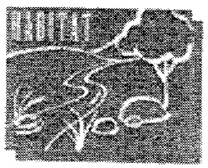
Fish Infrastructure: a Comprehensive Approach



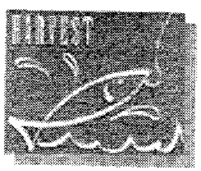
Improve fish passage and water quality at the Dams.



Reform outdated hatcheries.



Enhance and rehabilitate land and water habitat.



Support more selective fisheries.

Share responsibility for fish recovery among Federal Agencies.

Create a Unified Plan through partnerships with States and Tribes.

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N
P O W E R   B U S I N E S S   L I N E

PROPOSED CONTRACTS OR AMENDMENTS TO EXISTING CONTRACTS WITH THE REGIONAL INVESTOR-OWNED UTILITIES REGARDING THE PAYMENT OF RESIDENTIAL AND SMALL-FARM CONSUMER BENEFITS UNDER THE RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENTS FY 2007-2011

ADMINISTRATOR'S RECORD OF DECISION

MAY 25, 2004

BONNEVILLE
POWER ADMINISTRATION

Proposed Contracts or Amendments to Existing Contracts With the Regional Investor-Owned Utilities Regarding the Payment of Residential and Small-Farm Consumer Benefits Under the Residential Exchange Program Settlement Agreements FY 2007-2011

Administrator's Record of Decision

Bonneville Power Administration
U.S. Department of Energy

May 25, 2004

INTRODUCTION

This Record of Decision (ROD) addresses the comments and issues raised with respect to BPA's proposal to offer new contracts or amendments to existing contracts (proposed contracts) to each of the region's six investor-owned utilities.[1] The proposed contracts refine the manner in which BPA provides benefits from the Federal power system to the investor-owned utilities' respective residential and small farm consumers. BPA achieves two objectives with this proposal: (1) BPA provides a level of certainty for both the investor-owned utilities and BPA regarding the manner in which benefits for their residential and small farm customers are calculated and provided in FY 2007-2011; and (2) the contracts result in a reduction in the augmentation costs contained in the Load-Based Cost Recovery Adjustment Clause (LB CRAC), thereby contributing to lower rates for a large segment of BPA's customers. This ROD first discusses the Residential Exchange Program (REP), subsequent contractual agreements, and the contract proposal, and then describes and evaluates the public comments received on the proposed contracts.

In the proposed contracts addresses several aspects of the manner in which investor-owned utility benefits are provided. First, BPA elects to provide the equivalent of 2200 aMWs entirely as financial benefits during the FY 2007-2011 period.

Second, the proposed contracts also establish a mark-to-market methodology to determine the market price forecast used in the calculation of monetary benefit levels under the utilities' REP Settlement Agreements. Currently, the monetary benefits are calculated as the difference between a forecast of market prices established in BPA's rate case and the RL rate. The proposed contracts replace the rate case price forecast with a mark-to-market methodology to determine the market price.

Third, the contracts also provide a yearly $100 million floor and a $300 million cap for the financial benefits provided to the utilities' residential and small farm consumers for the FY 2007-2011 period.

Finally, the proposed contracts provide the investor-owned utilities with additional time to pass through these monetary benefits to their residential and small farm consumers. The existing REP Settlement Agreements specify the amount of benefits the investor-owned utilities can hold. Currently, the investor-owned utilities can hold benefits equal to the greater of the benefits provided six months prior to, or expected to be provided six months after, the actual pass-through of benefits to the residential and small farm customers. The new contracts extend that period to 36 months to provide the investor-owned utilities additional time to moderate their retail rate levels during the last five years of the contracts.

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[1] Puget Sound Energy, Contract No. 04PB-11467; PacifiCorp, Contract No. 04PB-11468; Avista, Amendment No. 3 to Contract No. 00PB- 12157; Portland General Electric, Amendment No. 2 to Contract No. 00PB-12161; Idaho Power Company, Amendment No. 3 to Contract No.00PB-12158; NorthWestern Energy, Amendment No. 3 to Contract No. 00PB-12160.

As a corollary to the decision to offer these contracts, BPA is proposing a clarification of Section III.C.2 of its 1998 BPA Power Subscription Strategy. Currently, the Power Subscription Strategy states that BPA will establish a market price forecast of power in a rate case, which will be used in calculating benefits for the utilities' residential and small farm customers. The proposed clarification to the Subscription Strategy allows BPA to calculate the level of monetary benefits using a market price from a mark–to-market methodology in the new contracts or, alternatively, one developed in a BPA rate case.

The proposed contracts with Puget Sound Energy, Inc. (Puget) and PacifiCorp also modify the $200 million reduction-of-risk discount contained in their Conditional Deferral Agreements (Contract Nos. 02PB-11156 and 02PB-11157, respectively). As part of the consideration for BPA's decision to offer the proposed changes to the contracts, Puget and PacifiCorp are willing to forego collection of one half of the reduction-of-risk discount payments, plus interest, and defer collection of the remaining amount until the FY2007-2011 period. The other four investor-owned utilities would provide consideration in the form of a waiver of the remaining portion of the monetary benefits due each of the utilities in their FY 2003 Deferral Agreements (Contract Nos. 03 PB-11268, Idaho Power; 03PB–11267, Portland General Electric Company; 03PB–11266, Avista Corporation; 03PB-11265, NorthWestern Energy).

The amounts deferred by Puget and PacifiCorp are anticipated to be collected as part of BPA's general revenue requirement during the FY2007-2011 period. All of BPA's power customers (including but not limited to Slice, non-Slice, investor-owned utility, and direct-service industrial) would pay the costs associated with the deferral.

BACKGROUND

BPA was created in 1937 to market electric power generated at the Bonneville Dam, and to construct and operate facilities for the transmission of power. 16 U.S.C. § 832-832l. Since that time, Congress has directed BPA to market power generated at additional facilities. 16 U.S.C. § 838f. Currently, BPA markets power generated at thirty-one Federal hydroelectric projects, and several non-Federal projects. BPA also owns and operates approximately 80 percent of the Pacific Northwest's high-voltage transmission system. In 1974, BPA became a self-financed agency that does not receive annual appropriations. *Id.* § 838i. BPA's rates must therefore produce sufficient revenues to repay all Federal investments in the power and transmission systems, and to carry out BPA's additional statutory objectives. *See* 16 U.S.C. §§ 832f, 838g, 838i, and 839e(a).

In the 1970s, forecasts of insufficient resources to meet the region's electricity demands led to passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) in 1980. 16 U.S.C. § 839, *et seq.* In that Act, Congress, among other things, directed BPA to offer new power sales contracts to its customers. *Id.* §§ 839c, 839c(g).

A. The Residential Exchange Program (REP)

Section 5(c) of the Northwest Power Act established the REP. *Id.* § 839c(c). Under the REP, a Pacific Northwest electric utility may offer to sell power to BPA at the utility's average system cost (ASC). *Id.* § 839c(c)(1). If offered, BPA purchases such power and, in exchange, sells an equivalent amount of power to the utility at BPA's PF Exchange rate. *Id.* The amount of the power exchanged equals the utility's residential and small farm load. *Id.* In past practice, no actual power deliveries have taken place. Instead, BPA provided equivalent monetary benefits to the utility based on the difference between the utility's ASC and the applicable PF Exchange rate multiplied by the utility's residential load.

The Northwest Power Act requires the investor-owned utilities to pass these monetary benefits directly to the utilities' residential and small farm consumers. *Id.* § 839c(c)(3). While REP benefits have previously been monetary, the Northwest Power Act also provides for the sale of actual power to exchanging utilities in specific circumstances. Pursuant to section 5(c)(5) of the Northwest Power Act, in lieu of purchasing any amount of electric power offered by an exchanging utility, the Administrator may acquire an equivalent amount of electric power to replace power sold to the utility as part of an exchange sale. *Id.* § 839c(c)(5). However, the cost of the acquisition must be less than the cost of purchasing the electric power offered by the utility. *Id.* In these circumstances, BPA acquires power from an in-lieu resource and sells actual power to the exchanging utility.

The REP has traditionally been implemented through Residential Purchase and Sale Agreements (RPSAs), the initial versions of which were executed in 1981.

B. Power Subscription Strategy ROD

In anticipation of the expiration of the then-current contracts and rates, the BPA Administrator issued a Power Subscription Strategy (Subscription Strategy) and accompanying Power Subscription Strategy ROD, (Subscription ROD) on December 21, 1998. These documents established the agency's direction regarding the post-2001 power sales contracts. The Subscription Strategy and Subscription ROD were the culmination of a lengthy and thorough public process that formed a framework to equitably distribute the benefits of electric power generated by the FCRPS among Pacific Northwest parties.

C. Total Amount of Investor-Owned Utility Settlement Benefits

BPA's principal goal in the Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region. The Subscription Strategy enabled the benefits of the FCRPS to flow throughout the region, whether currently served by publicly owned or privately owned utilities.

One aspect of the Subscription Strategy involved an offer to settle disputes regarding the implementation of the REP post 2001. Over the years BPA, the investor-owned utilities and public preference customers vigorously disputed the manner in which BPA determined the level of benefits for the residential and small farm consumers of the investor-owned utilities. In addition to offering investor-owned utilities the ability to participate in the traditional REP, the proposed Subscription Strategy offered the region's six investor-owned utilities access to the equivalent of 1800 aMW of Federal power for the FY 2002-2006 period. The offer provided that at least 1000 aMW of the 1800 aMW would be served with actual BPA power deliveries. The remainder would be provided through either a financial arrangement or additional power deliveries depending on which approach was most cost-effective for BPA.

The four Pacific Northwest state utility commissions (Commissions), in a letter dated July 23, 1999, requested that BPA increase the amount of the settlement from 1800 aMW to 1900 aMW for the FY 2002-2006 period. This request was made in order for the Commissions to arrive at a joint recommendation for allocating the settlement benefits among the IOUs for both the FY 2002-2006 and FY 2007-2011 periods. The Subscription Strategy already included a proposal to increase the equivalent amount of Federal energy to 2200 aMWs for the FY 2007-2011 period.

BPA sought comment on this proposed increase in settlement benefits. After review of public comments, BPA found the arguments for increasing the investor-owned utility settlement amount by 100 aMW to be compelling. Having previously established conditions for adopting any such increase, BPA determined that it expected to satisfy all such conditions. Therefore, BPA increased the amount of total benefits for the proposed settlements of the REP with regional investor-owned utilities from 1800 aMW to 1900 aMW for FY 2002-2011, and announced the change in BPA's Supplemental Subscription ROD.

D. IOU REP Settlement Agreements

After completion of the Administrator's Supplemental Subscription ROD, BPA began the development of a prototype Residential Purchase and Sale Agreement (RPSA) and a prototype REP Settlement Agreement. The prototype REP Settlement Agreement provided power sales pursuant to a contract offered under section 5(b) of the Northwest Power Act. The prototype REP Settlement Agreement also provided for the payment of financial benefits. At the specific request of the Montana Power Company, (the predecessor to NorthWestern Energy) BPA also proposed a prototype REP Settlement Agreement that provided power sales pursuant to section 5(c) of the Northwest Power Act.

On October 4, 2000, the BPA Administrator issued a decision document entitled "Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision," which concluded that it was appropriate to offer the REP Settlement Agreements to regional investor-owned utilities. The REP Settlement Agreements were then executed the same month with all of the region's investor-owned utilities.

E. Load Reduction Agreements

Beginning in the early summer of 2000 and for approximately the next 10 months, power prices on the West Coast increased to unprecedented levels. The increase in the wholesale price led a number of customers to place load on BPA above the amount BPA forecasted in its WP-02 rate case. Because BPA did not have sufficient generation to meet the original load forecast, the added load meant BPA would need to make additional purchases in the increasingly volatile wholesale market. These factors lead BPA to raise its rates by approximately forty-six percent to deal the increased expense of meeting its load obligations.

As one part of the effort to lessen the impact of these high market prices on BPA's ability to meet these firm load obligations, on April 9, 2001, the BPA Administrator asked BPA's customers to enter into agreements to reduce the load placed on BPA. These agreements would reduce the need to purchase power to meet loads under contracts negotiated pursuant to the Subscription Strategy during this period of historically high and volatile market prices of power.

BPA entered into load reduction agreements with both Puget and PacifiCorp that amended or replaced their original REP Settlement Agreements and removed BPA's obligation to deliver 619 aMWs of firm power for the first five years of those agreements (FY 2002-2006) in exchange for cash payments. BPA used the firm power not sold to Puget and PacifiCorp to meet its total firm obligations to publicly owned and cooperative customers, investor-owned utilities, and direct service industries.

Both load reduction agreements, PacifiCorp's Financial Settlement Agreement (Contract No. 01PB-10854) and Puget's Amended Settlement Agreement (Contract No. 01PB-10885), specifically provided that the respective utilities were willing to reduce the payments received under the agreements to well below then-prevailing forward market price if the respective utilities entered into settlement agreements with certain publicly owned utility and cooperative customers that waived and dismissed certain legal challenges. PacifiCorp and Puget believe there was risk associated with allowing BPA to buy the power purchases under its REP Settlement Agreement that were currently being challenged in court. As of June 2001, talks about potential settlement of litigation had been occurring between investor-owned utilities and public utility litigants. This provision was added to hold open the option for a reduced load reduction payment to Puget and PacifiCorp, in the event those talks were successful.

These payments are referred to as the "reduction-of-risk discount or payment." In order for BPA to avoid paying the reduction-of-risk discount to PacifiCorp and Puget, litigation settlements with publicly owned utility and cooperative customers had to occur by December 1, 2001. The amount of these payments for PacifiCorp and Puget combined is approximately $200 million. Absent executing the proposed contracts, the

$200 million would be recovered as a load reduction expense through BPA's wholesale power rates in the Load-Based Cost Recovery Adjustment Clause (LB CRAC).

F. Conditional Deferral Agreements

When no settlement was reached by December 1, 2001, BPA, PacifiCorp, and Puget negotiated Conditional Deferral Agreements. These agreements deferred recovery of the $200 million reduction-of-risk payments, in order to allow additional discussions to occur with regional parties that could settle pending litigation challenging BPA's REP Settlement Agreements with the investor-owned utilities. These agreements applied a negotiated interest rate to the $200 million reduction-of-risk discount payments for the period of the deferral.

G. Financial Choices and the FY 2003 Deferral Agreements

During the spring and summer of 2002, BPA's financial picture deteriorated. To address BPA's financial problems, on July 2, 2002, BPA sent a letter to rate case parties and other interested entities in the region announcing the beginning of the Financial Choices public comment process. The Financial Choices process examined a variety of financial and program options for addressing BPA's Power Business Line's (PBL) FY 2003-2006 financial challenges. In this process, BPA described the financial challenges, the actions BPA already had taken to address the challenges, and the financial outlook for the remainder of the rate period. Additionally, BPA identified a variety of potential financial alternatives that, separately or in combination, could form the basis of a solution to PBL's financial situation.

As a result of the Financial Choices process, BPA made decisions to cut, eliminate, or defer certain costs and expenses. BPA issued a Financial Choices close-out letter to the region on November 22, 2002, outlining BPA's plan, in part, for meeting the agency's financial challenges. The plan took into consideration extensive public input BPA received during the Financial Choices public process.

As an outgrowth of the Financial Choices process, BPA sought to defer payment in FY 2003 of certain amounts of financial benefits under the investor-owned utilities' REP Settlement Agreements and to facilitate a relatively uniform pass-through of benefits under the agreements. BPA viewed the deferral of these financial benefits as a tool to help avoid implementing a Safety-Net Cost Recovery Adjustment Clause (SN CRAC). Under these agreements the investor-owned utilities agreed to defer a total of $55 million in financial benefits from FY 2003 until the FY 2007-2011 period. The investor-owned utilities conditioned the deferral on whether BPA implemented an SN CRAC in FY 2003. In the event BPA implemented an SN CRAC, the investor-owned utilities would use the deferred financial benefits to pay any SN CRAC adjustment applied to their rates. In early 2003, BPA contemporaneously entered into agreements under which the investor-owned utilities and BPA agreed to a deferral of payments in FY 2003 under agreements amending provisions of the REP Settlement Agreements, known as "Agreements Regarding Fiscal Year 2003 Deferral Amount" or the "FY 2003 Deferral

Agreements." These agreements include: Avista Corporation, Contract No. 03PB-11265; NorthWestern Corporation, Contract No. 03PB-11269; PacifiCorp, Contract No. 03PB-11262; Portland General Electric (PGE), Contract No. 03PB-11267; Puget Sound Energy, Inc., Contract No. 03PB-11251; and Idaho Power Company, Contract No. 03PB-11268.

PROPOSED CONTRACT OFFERS TO THE INVESTOR-OWNED UTILITIES

A. Calculation of Monetary Benefits and Forward Flat-Block Price Forecast

Under the REP Settlement Agreements, monetary benefits are determined by the difference between BPA's Forward Firm-Block Price Forecast (FBPF) and the RL rate (or lowest PF rate in appropriate circumstances) multiplied by the amount of the investor-owned utility's benefits as stated in annual aMW.[2]

The REP Settlement Agreements currently provide the FBPF is "BPA's forecast of the wholesale market price for the purchase of additional amounts of power at 100 percent annual load factor established in the same BPA *power rate case* as that which established the RL rate and for the period of the RL Rate established in a BPA power rate case Record of Decision (ROD) as finally approved by the Federal Energy Regulatory Commission and affirmed, if appealed, by the United States Court of Appeals for the Ninth Circuit." (Emphasis added) The proposed contracts replace the use of a rate case power price forecast with a mark-to-market methodology that is functionally similar yet provides a desired transparency for determining the forecast.

Rather than using a rate case forecast to determine the FBPF, the contracts use an independent survey of market prices. The survey will use the prices for a flat block of firm power delivered at the Mid-C trading hub for each contract year. The survey will be done quarterly and a mean price for this power product will be determined (after eliminating the highest and lowest prices). This mean price will serve as the FBPF for purposes of calculating the monetary benefit levels.

[2] The current allocation of aMWs for each of the investor-owned utilities, as reduced for assignment to BPA pursuant to the respective agreements, is as follows:

	FY2002-2006	FY2007-2011
Avista Corp.	90	149
Idaho Power Company	120	224
NorthWestern Energy	24	28
PacifiCorp (Total)	473.6406	586.8481
PacifiCorp (UP&L)	140	140
PacifiCorp (PP&L – WA)	80	108
PacifiCorp (UP&L – OR)	253.6406	338.8481
Portland General Electric	490	560
Puget Sound Energy (PSE)	700	648
Total	1897.6406	2195.8481

B. Qualified Third Party/Eligible Data Providers

As a first step to implement the new methodology, BPA must hire a qualified third party (QTP) to collect the necessary market data. A QTP will be selected from among the Big 4 accounting firms or from a list of entities that have expertise in the electric power industry, including expertise in financial and risk accounting for the electricity power industry. For each Contract Year, the QTP randomly selects 6 to 8 Eligible Data Providers (EDPs) to provide price information. EDPs are entities that routinely buy and sell bulk power for resale in the Pacific Northwest (PNW) and use risk accounting for reporting in the regular course of business. The list of EDPs will consist, if possible, of at least two PNW publicly owned utilities, two PNW investor-owned utilities, and two marketers among other eligible entities.

The QTP will survey the market for the price of a block of firm power delivered at Mid-C for four consecutive quarters (the first of which commences 21 months prior to the beginning of each Contract Year, and the last of which ends 9 months prior to each Contract Year) from the list of EDPs. Following the completion of each quarterly survey, the QTP excludes the highest and lowest forward prices from the EDPs surveyed during each such quarter. The QTP then calculates the arithmetic mean of the remaining Forward Price Data to determine that quarter's FBPF (the "Quarterly FBPF") for the Contract Year. Following the completion of the four Quarterly FBPFs, the QTP calculates the arithmetic mean for the Quarterly FBPFs. The result of this calculation is the FBPF that is used for the Contract Year to calculate the level of monetary benefits.

C. Additional Transparency for the FBPF

As noted previously, the current method used to calculate the FBPF is through BPA's forecast of the wholesale market price in BPA's power rate cases. Investor-owned utilities expressed concern that BPA views the investor-owned utilities' REP settlement benefits as an agency cost. Because BPA is frequently under pressure to reduce costs and therefore rates, the investor-owned utilities believed this environment could create the appearance that the Administrator would view the determination of the FBPF as a means to reduce costs. The investor-owned utilities suggested that a more transparent method of establishing the FBPF would eliminate using the calculation of the FBPF as a means to lower costs. To achieve this goal, the parties developed the methodology described above. Through this methodology, an independent QTP surveys numerous market participants in order to obtain forward price data, which is averaged to determine the FBPF. This removes any appearance of opportunity for BPA to establish an artificially low or high FBPF rate case forecast.

D. Floors and Caps

A separate concern involved the potential that the mark-to-market methodology could result in very high or very low benefit levels for the residential and small farm customers depending upon the differential between the market price and the RL rate. As a result, BPA and the investor-owned utilities included provisions that both guaranteed a minimum level of benefits and at the same time capped the upper level of monetary benefits. The proposed contract establishes a floor of $100 million per year for investor-owned utility benefits, and a cap of $300 million per year for investor-owned utility benefits. Through the floor, BPA ensures the residential and small farm customers of the region's investor-owned utilities receive a specified minimum level of benefits. Similarly, through the cap, BPA's other customers are assured that investor-owned utility benefits will not exceed a specified amount.

E. Election of All Monetary Benefits for Investor-Owned Utilities

The REP Settlement Agreements provide BPA with the option to elect the actual amount of power and monetary benefits for the FY 2007-2011 period by October 1, 2005, one year prior to the beginning of the next rate period. This option has introduced a great deal of uncertainty for the investor-owned utilities in their resource planning process. To address this uncertainty, the proposed contracts provide that BPA will make the decision now to provide all of the benefits as monetary benefits.

In the proposed contracts, BPA agrees it will provide no firm power under the REP Settlement Agreements for the FY 2007-2011 period. As a consequence, the proposed contracts will reduce the loads served by BPA, and thus reduce BPA's need to rely on power purchases from the sometimes volatile and unpredictable wholesale power market to serve its loads.

Thus, the proposed contracts provide the investor-owned utilities with the needed information to assist them with their resource planning during the final five years of their contracts.

F. Pass-Through of Benefits to Residential and Small Farm Consumers

An additional aspect of the proposed contracts involves the pass-through of benefits to the investor-owned utilities' residential and small farm consumers. Under the proposed contracts, the investor-owned utilities are given an extended period of time to pass through the benefits to these consumers. Under the existing agreements, as amended by the FY 2003 Deferral Agreements, the investor-owned utilities can hold benefits equal to the greater of benefits received six months prior to the pass-through or benefits expected six months after the pass-through before they must pass the benefits to the residential and small farm consumers. Under the proposed contracts, periods before and after the pass-through are extended to thirty-six months. This change is designed to allow the investor-owned utilities to spread the payment of the benefits to allow them to moderate the potential variations in rates for their residential and small farm consumers.

G. Clarification of Subscription Strategy

As part of the decision to offer the proposed contracts to the investor-owned utilities, BPA is also proposing to clarify Section III.C.2 of its 1998 BPA Power Subscription Strategy. The Power Subscription Strategy as currently written, states:

> For the amount of subscription sales not made through physical power deliveries, BPA will provide a cash payment that reflects the difference between the market *price of power forecast in the rate case* and the rate used to make such subscription sales.

(Emphasis added). It further provides:

> Under the 10-year contract, BPA will guarantee 1,800 aMW of power or financial benefits for the 2002-2006 period and 2,200 aMW for the 2007-2011 period. BPA intends for this 2,200 aMW to be all power deliveries. If BPA is unable to deliver all power for the 2007-2011 period, a mechanism similar to that described above will be used for determining the financial component payment.

As noted above, BPA and the investor-owned utilities agree through the proposed contracts that the benefits for the FY 2007-2011 period will be entirely financial benefits. There is also agreement to use a mark-to-market methodology to calculate the financial benefits. While BPA intended to provide these benefits entirely in the form of power deliveries, changes in BPA's loads and in the wholesale market since BPA's 1998 decision no longer make this practical. BPA's loads increased significantly over the levels assumed at the time BPA issued the Subscription ROD. This unforeseen increase in loads forced BPA to purchase more power in the wholesale market to make up the difference between its own generation and its load obligations. In addition, the wholesale power market has been marked by dramatic price swings in recent years. By opting to provide the investor-owned utilities only financial benefits, BPA can limit its exposure to the sometimes volatile wholesale market.

The Subscription Strategy also provides that the investor-owned utilities' financial benefits would be based on the difference between the market price and the rate paid for power (FBPF and the RL rate in the REP Settlement Agreement). The Subscription Strategy further provides that if BPA provides financial benefits in the FY 2007-2011 period, it will use a "mechanism similar" to the rate case price forecast. BPA believes the mark-to-market methodology outlined in the proposed contracts is a similar mechanism. The mark-to-market methodology does not materially change the manner in which the financial benefits are calculated. It does, however, provide all parties with a more transparent method for calculating the market price used in the formula. While BPA believes this proposal merely clarifies the Subscription Strategy, BPA nevertheless put this matter out for public comment.

H. Challenges to Investor-Owned Utility Benefits

There are a number of lawsuits pending before the Ninth Circuit Court of Appeals challenging the manner in which BPA is providing benefits to the investor-owned utilities. The current contracts are not contingent upon the dismissal of any pending litigation. While the proposed contracts do not require dismissal of any pending litigation, the contracts recognize that the outcome of pending litigation could impact the parties' bargained for consideration. As previously noted, the financial benefits are currently determined by a formula based on the difference between BPA's rate case market price forecast (the FBPF) and the RL rate (or lowest PF rate in appropriate circumstances) multiplied by the amount of the investor-owned utility's benefits as stated in annual aMW. The FBPF and benefit levels are impacted by the proposed contracts. The proposed contracts reflect the basic formula for calculating benefits contained in the REP Settlement Agreements as they currently exist. The caps, floors and mark-to-market methodology all relate back to the manner in which BPA calculates the financial benefits for the investor-owned utilities as established in the REP Settlement Agreements. If the courts strike down the manner in which BPA provides benefits under the REP Settlement Agreements, the foundation for the proposed contracts disappears. As a result, if the court were to invalidate the REP Settlement Agreements, BPA and the investor-owned utilities have agreed that the proposed contracts would be void *ab initio* since the foundation for calculating benefits in the REP Settlement Agreement would no longer exist. If the proposed contracts are voided, the parties would revert back to the existing agreements to the extent applicable.

I. Consideration for Amendments to REP Settlement Agreements

The proposed contracts with Puget and PacifiCorp include modification of the $200 million reduction-of-risk discount contained in their Conditional Deferral Agreements (Contract Nos. PB02-11156 and PB02-11157, respectively). As part of the consideration for BPA's decision to offer the proposed changes to Puget and PacifiCorp's contracts with BPA, they are willing to forego collection of one half of the reduction-of-risk discount payments, plus interest, and defer collection of the remaining amount until the FY2007-2011 period. The other four investor-owned utilities would provide consideration in the form of a waiver of the remaining portion of the monetary benefits due each of the utilities in their FY2003 Deferral Agreements. (*See* Contract Nos. 03PB-11268, Idaho Power; 03PB-11267 Portland General Electric Company; 03PB-11266, Avista Corp.; 03PB-11265, NorthWestern Energy.)

J. Payment of Deferred Amounts to PacifiCorp and Puget

Under the proposed contracts, the amounts deferred by PacifiCorp and Puget amounts to just over $100 million. BPA currently envisions these deferred reduction-of-risk payments will be part of BPA's general revenue requirement during the FY 2007-2011 period. As a result, BPA customers will not see reduction-of-risk dollars as part of their rates during the current rate period, but will see these dollars as part of their power rates during the FY 2007-2011 period.

Currently, reduction-of-risk dollars are collected as part of the LB CRAC and rates are adjusted accordingly. However, not all of BPA's customers are obligated to pay the LB CRAC. Customers who signed pre-Subscription contracts are not obligated to pay the LB CRAC.

In its next rate case, BPA anticipates it will propose these deferred amounts will be included as part of its general revenue requirement. By doing so, all BPA customers, Slice, non-Slice, investor-owned utilities and direct service industries, would pay a portion of these deferred dollars. However, any actual decision regard the rate treatment of these costs will be resolved in those future 7(i) proceedings.

RESPONSE TO PUBLIC COMMENTS

On April 16, 2004, BPA sent a letter to interested parties in the region informing them of the proposed contracts and asking for public comments. The public comment period ended on May 14, 2004. BPA received a total of 42 comments as a result of the letter.

***Issue 1*:** *Whether the proposed contracts provide near-term rate relief for BPA's customers.*

Comments: The City of Ashland, Clark Public Utilities, Cowlitz County Public Utility District, Emerald People's Utility District, Flathead Electric Cooperative, Idaho Public Utility Commission, Midstate Electric Cooperative, Inc., Northern Wasco People's Utility District, Seattle City Light, Public Utility District No. 1 of Skamania County, Springfield Utility Board, Tillamook People's Utility District, Wells Rural Electric Company and Western Montana Electric Generating and Transmission Cooperative, all submitted written comments in favor of the proposed contracts. The comments focused primarily on the rate relief afforded these customers that would result from the cost reductions and deferrals in the proposed contracts.

The Superintendent of Seattle City Light stated "[t]he effort to restructure the terms, is from my point of view, clearly beneficial to the region's publicly owned utilities, including Seattle City Light. I understand that the restructured contracts may allow you to avoid a near-term rate increase that many utilities would be forced to pass along to their retail customers." The City of Ashland also stated that it supported going forward with the proposal due to the near-term rate relief it afforded the City. The City of Tacoma viewed the proposed contracts as an opportunity to "reduce BPA's near term costs and provide a real opportunity to deliver rate relief." Clark, Emerald, Flathead, Midstate, Skamania PUD, Springfield, Tillamook, and Wells all submitted similar comments regarding the positive benefits of the near-term rate relief afforded by the proposed contracts.

Western Montana expressed some reservations regarding deferring costs until the next rate period, but nevertheless concluded that the overall benefits of near-term rate relief outweighed their concerns regarding the deferral.

Cowlitz PUD also noted that even though it did not endorse the payment of the underlying reduction-of-risk dollars, it nevertheless believes that the proposed contracts are "a crucial part of BPA's rate reduction efforts" and encouraged BPA to go forward with the proposed contracts.

Northwest Requirements Utilities (NRU) submitted comments on behalf of a majority of its members that viewed the proposed contracts as a necessary part of an overall strategy for rate relief in the region. NRU commented that the contracts, in combination with seeking a reduction in summer spill and a pledge by the Administrator to seek $100 million in cost cuts and revenue enhancements, provide a meaningful opportunity for near-term rate relief. NRU also viewed the ability to continue with litigation challenges as an important part of the overall strategy.

Northern Wasco PUD submitted comments similar to NRU's. Northern Wasco PUD also supported the proposal and viewed it as part of an overall strategy for rate relief that included the continued efforts of the Sounding Board to achieve cost reductions and revenue enhancements, as well as getting approval to reduce summer spill.

Alcoa submitted comments that noted the proposed cost deferrals are not a substitute for cost reductions. Alcoa expressed a concern that BPA must not consider the $100 million in deferrals as a cost reduction and must continue its efforts to obtain real and permanent cost reductions.

In addition, a number of employees of aluminum smelters in the region submitted comments generally in favor of the proposed contracts because of the favorable impact it would have on the price of power. However, some of the comments submitted by other aluminum workers conditioned their support upon obtaining assurance from BPA that rates for power in the next rate period would not exceed $30/MWh.

Evaluation: BPA believes the proposed contracts present an opportunity to offer significant near-term rate relief to all of BPA's customers that pay the LB CRAC. The proposed contracts with Puget and PacifiCorp include modification of the $200 million reduction-of-risk discount contained in their Conditional Deferral Agreements (Contract Nos. 02PB-11156 and 02PB-11157, respectively). As part of the proposed contracts, Puget and PacifiCorp forego collection of one-half of the reduction-of-risk discount payments, plus interest, and defer collection of the remaining amount until the FY2007-2011 period. Absent executing the proposed contracts, the $200 million would be recovered as a load reduction expense through BPA's wholesale power rates in the Load-Based Cost Recovery Adjustment Clause (LB CRAC) in FY 2005-2006.

It should be noted that, removing $200 million from BPA's power costs for FY 2005-2006 would make power rates about 6 percent lower in those two years than absent the proposed contracts. The actual level of BPA's power rates in FY 2005-2006 depends on many factors, including the success of the Sounding Board's efforts to reduce BPA's costs, the National Oceanic and Atmospheric Administration Fisheries' decision regarding the summer spill proposal, the amount and timing of this year's runoff, and market prices.

BPA agrees with the comments submitted by NRU, Northern Wasco, and others that view the proposed contracts as a constructive part of an overall strategy to reduce

BPA rates. The fallout from the 2000-2001 west coast energy crisis is still felt by the region. While the proposed contracts help address some of the impact, it is only one piece of a larger strategy to reduce BPA's costs and enhance its revenues. Alcoa is correct in noting that the deferral of the $100 million is not a cost reduction and that to achieve significant rate reductions in the future BPA, must continue efforts in the Sounding Board, and elsewhere, to cut costs where possible.

A number of aluminum workers conditioned their support for the proposal on BPA assuring that its rates in the FY 2007-2011 period will not exceed $30/MWh. BPA, however, cannot provide such assurance in the context of this ROD without violating applicable statutory provisions regarding BPA ratemaking. BPA's rates for the FY 2007-2011 period must be set in a future rate case consistent with section 7(i) of the Northwest Power Act. If BPA were to provide the requested assurance, BPA would be predeciding ratemaking issues that can only be made in a section 7(i) rate hearing based on the record developed in that hearing. While the proposed amendments will have a limited upward pressure on rates for the next rate period (currently forecasted to result in approximately a 1 percent increase on rates) many other factors will have a significantly greater influence on determining BPA's power rates during that period.

Decision: The proposed contracts provide meaningful near term rate relief for customers subject to the LB CRAC by removing approximately $200 million in load reduction expenses from BPA's power costs from the LB CRAC for the FY 2005-2006 period. While the current proposal assists in reducing rates, it is only a part of the efforts BPA is undertaking to reduce its costs and enhance its revenues over the coming months and years.

Issue 2: *Whether the deferral of $100 million in reduction-of-risk payments to the FY 2007-2011 period is consistent with the rate lock provisions in BPA's pre-Subscription contracts.*

Comments: Columbia Rural Electric Association, Kootenai Electric Cooperative and Modern Electric Water Co. submitted similar comments objecting to the proposed contracts. The crux of their collective concern involves the proposal to defer $100 million associated with the reduction-of-risk payments to the FY 2007-2011 period. Although the arguments are structured slightly differently, these utilities contend that this decision breaches their respective pre-Subscription contracts with BPA.

Columbia contends its pre-Subscription contract prohibits BPA from adjusting its rates during the FY 2002-2006 period. According to Columbia, this means that BPA cannot adjust Columbia's rate for the LB CRAC. Based on this, Columbia believes BPA is effectively violating this rate lock by deferring the reduction-of-risk payments to the FY 2007-2011 period when these costs will be incorporated into the rate charged Columbia and others with pre-Subscription contracts.

Evaluation: The proposed contracts defer approximately $100 million plus interest due PacifiCorp and Puget under the reduction-of-risk provisions to the FY 2007-2011 period. By deferring the payments until the next rate period, Columbia, Kootenai and Modern, along with all other customers, will likely have these dollars included in their rates during the FY 2007-2011 period. However, the decision on whether to include these dollars as part of BPA's general revenue requirement will ultimately be made in a future 7(i) hearing.

Columbia correctly notes that BPA's pre-Subscription contracts lock the rates under those contracts for the FY 2002-2006 period. As a result of the rate lock, the rates charged Columbia, Kootenai and Modern, as well as all the other pre-Subscription contract holders, are not upwardly adjusted for any of the CRACs (LB, FB or SN) during FY 2002-2006. The LB CRAC is designed to capture additional costs associated with augmenting BPA's system. These augmentation costs include the load reduction agreements with PacifiCorp and Puget, which include the reduction-of-risk payments. Because Columbia, Kootenai and Modern do not pay the LB CRAC, each has avoided any obligation to pay the additional costs associated with augmenting Federal power, including the reduction-of-risk payments associated with PacifiCorp and Puget's load reduction agreements. These costs, it should be noted, were largely incurred after the pre-Subscription contracts were entered into.

Contrary to Columbia, Kootenai and Modern's contentions, the pre-Subscription contracts are not violated by the deferral of the reduction-of-risk payments. BPA's rate lock promise applies only to the FY 2002-2006 period. There are no assurances in their contracts with regard to fixed rates for the FY 2007-2011 period. The proposed contracts do not impact the current rate charged under pre-Subscription contracts, so there is no violation of the rate lock. In addition, BPA has not "effectively" violated the rate lock promise by deferring these dollars to the FY 2007-2011 period as argued by Columbia. The pre-Subscription contracts do not contain any assurance about how or when BPA will recover its costs. Additionally, the pre-Subscription contracts do not provide any shield against paying augmentation costs. The pre-Subscription contracts merely provide the utilities with an assurance that their rates will not change during the first five years of the contracts (FY 2002-2006). There is nothing in the proposed contracts that changes the rates paid under those agreements during this period.

Columbia's argument also assumes that the pre-Subscription contracts require BPA to contract for the sale of power and collect rates in a specified manner. BPA does not agree that its decision to sell a specified amount of power at a fixed price under the pre-Subscription agreements impacts its ratemaking either during the current rate period or for subsequent rate periods. BPA's ratemaking directives require it to recover its total costs.

BPA also believes pre-Subscription customers obtain a benefit from the proposed contracts. The proposed contracts include a cap on the amount of benefits that BPA will provide to the investor-owned-utilities during the FY 2007-2011 period. BPA believes that proposing these costs be included as part of the general revenue requirement in the next rate proceeding is appropriate given the benefit provided by the cap. It should be noted that any decisions regarding the allocation of these costs among customer classes will ultimately be made in a future section 7(i) rate proceeding.

Finally, providing rate relief during this rate period is of utmost importance to BPA. The proposed contracts will allow BPA to avoid over $100 million in costs and will defer approximately $100 million from the current rate period. Providing near term rate relief to BPA's other customers is of paramount importance and outweighs the costs pre-Subscription customers will be exposed to in the FY 2007-2011 period.

Decision: The proposed contracts, by deferring the reduction-of-risk payments to FY 2007-2011, do not violate the rate lock provisions of pre-Subscription contracts. The proposed contracts do not impact the rates currently charged to pre-Subscription contract holders. Similarly, BPA does not "effectively" violate the agreement by deferring the costs because the pre-Subscription contracts do not contain any provisions limiting the manner in which BPA recovers its costs.

Issue 3: *Whether the deferral of the reduction-of-risk payments to FY 2007-2011 violates BPA's rate directives or established regulatory policy.*

Comments: Columbia believes that deferring the reduction-of-risk costs into future rate periods violates BPA's statutory obligation to set rates to adequately recover its costs. Columbia contends that BPA will fail to set its rates high enough to recover its costs if it defers payment of the reduction-of-risk discount and does not use the LB CRAC to recover the associated costs during the current rate period.

Columbia also maintains that the deferral violates established regulatory policy. It maintains that Federal regulatory law follows the "matching principle" that requires costs to be assigned to the periods in which the benefits are expected and rates are to be paid. Columbia cites *American Electric Power Service Corp.*, 104 FERC ¶ 61,013 (2003) ("*American Electric*") in support of this proposition.

Evaluation: BPA's rate directives are not violated by the proposed deferral. While BPA's rate directives require BPA to recover its total system costs, the deferral of costs does not violate those directives. As noted above, PacifiCorp and Puget will provide BPA with a notice terminating the deferral and asking for payments to begin October 1, 2006. By such notice, the payment obligation associated with the reduction-of-risk discount will not arise during the current rate period. As a result, BPA will not fail to recover its costs during the current rate period, as Columbia suggests, but rather, the payment obligation associated with the cost will arise and be paid during the next rate period.

Additionally, Columbia's reliance on Federal regulatory law and *American Electric* case are misplaced. *American Electric* was based on the Federal Power Act. The Federal Power Act does not apply to BPA's wholesale power ratemaking. BPA's wholesale power ratemaking is conducted pursuant to the Northwest Power Act and BPA's organic legislation.

Columbia's reliance on the *American Electric* is misplaced for additional reasons. *American Electric* involved a request to defer certain costs associated with the start-up of a Regional Transmission Organization (RTO) until those costs could be recovered through rates. The applicability to this matter is questionable on several fronts. First, as noted previously, it involves FERC regulation of a utility under the Federal Power Act, which does not apply to BPA's power sales or ratemaking. Second, the Commission allowed American Electric Power to defer the start-up costs and collect them in a future period. This is directly contrary to the position argued by Columbia. Finally, *American Electric* involved issues surrounding the costs associated with the establishment of an RTO and has nothing to do with wholesale power rates.

Decision: The deferral of the reduction-of-risk payments does not violate BPA's rate directives or applicable Federal regulatory law.

Issue 4: *Whether the reduction-of-risk discount is unenforceable and unlawful.*

Comment: Canby argues that it has the right to appeal BPA's final actions to the United States Court of Appeals for the Ninth Circuit. 16 USC § 839f(e)(5). Canby contends that the reduction-of-risk discount interferes with those rights by penalizing public power utilities for not dismissing their petitions. Canby believes that the reduction-of-risk discount implicates fundamental rights under the United States Constitution, including the First Amendment right to petition the government for redress of grievances.

Industrial Customers of Northwest Utilities (ICNU) also asks about the circumstances under which BPA is legally obligated to pay the reduction-of-risk discounts.

Evaluation: BPA agrees that parties have the right to file *timely* challenges to BPA's final actions in the Ninth Circuit. Canby's comments, however, relate solely to the initial establishment of the reduction-of-risk discounts, not to the deferral of the existing discounts. The establishment of the reduction-of-risk provisions is not at issue in this proceeding. The reduction-of-risk discounts were established in BPA's Load Reduction Agreements with PacifiCorp and Puget, which were executed on May 23, 2001, and June 11, 2001, respectively. Under the Northwest Power Act, challenges to the Load Reduction Agreements were required to have been filed within 90 days of the execution of such Agreements. 16 U.S.C. § 839f(e)(5); *Bell v. Bonneville Power Admin.*, 340 F.3d 945, 948 (9th Cir. 2003). The issue presented in the instant case is simply whether BPA should offer the proposed contracts to the investor-owned utilities. Furthermore, questions regarding the legality of the Load Reduction Agreements are the subject of pending litigation. In summary, challenges to the original establishment of the reduction-of-risk discounts are outside the scope of this proceeding.

Decision: The legality of the previously negotiated reduction-of-risk discounts is outside the scope of this proceeding and will not be addressed here.

Issue 5: *Whether the mark-to-market methodology for calculating monetary benefits for the investor-owned utilities in the proposed contracts is consistent with the section 7(b)(2) rate test.*

Comments: Canby and ICNU pose questions to BPA about how it will perform the section 7(b)(2) rate test using the mark-to-market methodology in BPA's next wholesale power rate case. Neither Canby nor ICNU provide any substantive comment on this issue, but rather merely ask BPA to speculate on how it will handle this matter in BPA's next rate proceeding.

Canby asked the following set of questions:

1. Does BPA propose to implement the 7(b)(2) rate test under the new investor-owned utility methodology? If so, how?
2. If the rate test "triggers," will BPA adjust the level of investor-owned utility benefits?
3. If BPA will not adjust the level of investor-owned utility benefits, then who pays for the protection afforded to public power under the Northwest Power Act? Will those costs be shifted to DSI rates?
4. If the DSIs do not buy a sufficient amount of power from BPA, then who is left to pay for the cost of protecting public power from the triggering of the 7(b)(2) test?
5. What happens to the Residential Exchange Program for public power utilities? Can they still participate in the REP after October 1, 2006? If so, will BPA apply the 7(b)(2) rate test to their benefits?

ICNU similarly asked:

1. Whether the Agreements will impact BPA's statutory obligation to ensure that rates of preference customers are no higher than if the Administrator did not provide financial benefits to the investor-owned utilities. Northwest Power Act, 16 USC §839e(b)(2). For example, will any of the financial benefits provided to the investor owned utilities under the agreements be subject to the rate ceiling test under Section 7(b)(2) of the Northwest Power Act.

Evaluation: Pursuant to section 7(i) of the Northwest Power Act, BPA can only resolve issues regarding BPA's ratemaking in formal evidentiary hearings conducted in accordance with that section. All issues regarding the implementation of section 7(b)(2) of the Northwest Power Act and the allocation of BPA's costs will be resolved in future BPA section 7(i) hearings.

Similarly, Canby has inquired about BPA's plans for implementing the REP with BPA's public agency customers. The current proceeding only concerns the proposed contracts to eliminate a portion of the reduction-of-risk discount, defer an additional portion, and establish a FBPF for use in calculating future monetary benefits. Issues regarding BPA's implementation of the REP are outside the scope of this proceeding.

***Decision*:** Issues regarding BPA's future ratemaking can only be decided in a formal evidentiary section 7(i) hearing. Such issues are outside the scope of this proceeding. Similarly, issues regarding implementation of the REP are outside the scope of this proceeding. In any case, the questions regarding the 7(b)(2) rate test exist with or without BPA deciding to go forward with the proposed contracts.

***Issue 6*:** *Whether BPA should delay the issuance of this ROD and make the proposed contracts part of the Regional Dialogue process.*

Comments: Canby requests that BPA move its decision regarding the proposed contracts into the Regional Dialogue forum. Canby notes that BPA informed interested parties in February 2004 that it would consider the REP and related issues in the Regional Dialogue process. Rather than following its announced process, Canby argues BPA has developed this separate expedited proceeding. Canby believes that this will fragment the Regional Dialogue's decision making process.

Evaluation: BPA does not believe it is appropriate to move the decisions on the proposed contracts to the Regional Dialogue forum because the timing of the Regional Dialogue conflicts with the need to make timely decisions regarding the proposed contracts.

The Regional Dialogue is a forum where a number of issues related to BPA's future obligations and role in the region are being discussed. Under the current plan, the Regional Dialogue will culminate in a decision document in the coming months on a wide range of issues. This timetable conflicts with the decision timetable for the reduction-of-risk payments. The Conditional Deferral Agreement requires PacifiCorp and Puget to elect by June 3, 2004 whether they intend to terminate the existing deferral and thereby begin to receive payments in the next fiscal year. BPA's preferred option is to execute the proposed contracts with PacifiCorp and Puget prior to June 3, 2004.

BPA prefers this option because it avoids the possibility of unnecessarily increasing the LB CRAC. The LB CRAC for the October 1, 2004 to March 31, 2005, period is set in mid-June. BPA fully anticipates receiving notices from PacifiCorp and Puget terminating the deferral. This belief is based upon an order from the Oregon Public Utilities Commission directing PacifiCorp to terminate the deferral and representations by Puget that it intends to do the same. Absent execution of the proposed contracts by the investor-owned utilities, BPA fully expects PacifiCorp and Puget to seek payment of the full $200 million plus interest.

If PacifiCorp and Puget terminate the existing deferral, it is possible that each could ask for the payments to begin as soon as possible. The reduction-of-risk payments will be collected through an upward adjustment to the LB CRAC. If BPA waits until the Regional Dialogue has concluded to make a decision regarding the proposed contracts, the LB CRAC set in mid-June could include dollars for the reduction-of-risk payments.

To avoid this problem, BPA placed this decision on a different timetable. By negotiating a contract with the investor-owned utilities and putting it out for comment prior to the LB CRAC decision date, BPA provided Canby and others the ability to comment on the proposed changes and not run the risk of unnecessarily raising the LB CRAC.

The issues raised by these proposed contracts do not fully address the issues surrounding the provision of benefits to the investor-owned utilities. Regional Dialogue is addressing a variety of issues regarding the future of its relationship with the region's investor-owned utilities. Those issues will still need to be addressed in that forum. By resolving the issues surrounding the decision to offer these contracts in this ROD, BPA is not precluding Canby or others from presenting its opinion on the other investor-owned utility issues that are still being discussed in Regional Dialogue.

***Decision*:** BPA's decision regarding the proposed contracts will be made in this ROD and not shifted to the Regional Dialogue.

***Issue 7*:** *Whether BPA is obligated under certain circumstances to pay PacifiCorp and Puget the entire $200 million reduction of risk payment under the proposed contracts.*

Comments: Canby contends that there is an inconsistency between BPA's April 16, 2004, letter that sought public comment and the proposed contracts. Canby contends that the letter states that PacifiCorp and Puget will waive $100 million of the reduction of risk discount and defer collection of the other $100 million until the FY 2007-2011 period. Canby further notes that the contract "suggests that BPA may be required to pay the full amount under certain circumstances." To resolve the inconsistency, Canby posits the following questions:

1. Under what circumstances do PacifiCorp and Puget have the right to the full reduction of risk payment?
2. Why would a ruling invalidating the REP Settlement Agreement also not invalidate the reduction of risk payment?

ICNU also asks about the circumstances when BPA would be obligated to pay PacifiCorp and Puget the full reduction of risk payments.

Evaluation: BPA's letter and the proposed contracts are consistent. Canby's concern appears to be with section 4(c) of the proposed contracts. Section 4(c) provides that if section 4(c) of the REP Settlement Agreement is void, unenforceable or unlawful, then the proposed contracts that are the subject of this ROD shall likewise be rendered void *ab initio.* Section 4(c) of the REP Settlement Agreements with PacifiCorp and Puget involves the determination of benefits for the respective investor-owned utilities. The proposed contracts modify that section to include the caps and floors along with the new methodology for calculating the FBPF. The insertion of the language in section 4(c) of the proposed agreements is designed to deal with the situation that would arise if the court strikes the underlying formula in the REP Settlement Agreement. The proposed modifications to include a cap, floor as well as the new FBPF methodology all relate to the formula for calculating monetary benefits (i.e., FBPF-RL rate) and the proposed contracts become meaningless if there is no formula to which to apply the cap, floor or new methodology.

Voiding the proposed contracts does not mean that PacifiCorp or Puget will automatically be entitled to payment of the full $200 million as Canby's second question assumes. Any court order invalidating the REP Settlement Agreement formula may or may not impact BPA's obligations to make the reduction of risk payments. Attempting to speculate about the form of the court's order is a fruitless exercise. This agreement only returns parties to their positions prior to the execution of the proposed contracts. The court will ultimately resolve any question regarding the extent of BPA's obligation to make a reduction of risk payment or a payment under the FY 2003 Deferral Agreements.

BPA believes the benefits of near term rate relief outweigh any impact caused by litigation voiding the application of the proposed contracts. Regardless of the application of section 4(c), BPA's customers will receive near term rate relief. BPA will not face any higher costs from the application of section 4(c) than the costs BPA would face if the proposed contracts were not offered.

Decision: Whether BPA will be obligated to pay PacifiCorp and Puget the entire $200 million reduction of risk payment if a court order results in voiding the proposed contracts is impossible to determine at this time without such court order. Regardless of the outcome of the litigation, BPA' customer's will receive the important benefit of near term rate relief.

Issue 8: *Whether the proposed contracts are consistent with REP statutory provisions.*

Comments: ICNU asks whether BPA believes the proposed contracts are consistent with the REP statutory provisions and what the investor-owned utilities might be entitled to under a traditional REP.

Evaluation: The consistency of REP Settlement benefits with the REP is an issue that was previously addressed by BPA in the establishment of the REP Settlements. *See* "Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision." Because this issue was previously decided, it is not being revisited in this proceeding. Also, BPA's previous decision is the subject of pending litigation.

***Decision*:** The consistency of REP Settlement benefits with REP benefits was previously addressed by BPA in a separate forum and will not be revisited in this proceeding.

***Issue 9*:** *What is the impact of the proposed contracts on BPA's rates?*

Comments: ICNU asks what the rate impact of the proposed contract would be.

Evaluation: BPA's April 16, 2004, letter, which sought public comments on the proposed contract, stated:

> Removing $200 million from BPA's power costs for FY 2005-06 would make power rates about 6 percent lower in these two years with this agreement than without it. This year's dry spell is tending to push rates in the other direction, and could overwhelm the impacts of this and other successes at reducing costs. The actual level of power rates in FY 2005-06 depends on many factors, including the success of the Sounding Board efforts, National Oceanic and Atmospheric Administration Fisheries' decision regarding the summer spill proposal and this year's runoff and market prices. We won't know the final results for FY 2005 rates until August 2004.
>
> Assuming BPA receives approval from its auditors, the $100 million would be deferred to FY 2007-2011 and would add $20 million plus interest to BPA's general revenue requirement for each of these five years. All of BPA's power customers (Slice, non-Slice, investor-owned utility, and direct-service industrial) would pay these additional costs. This deferral would make power rates in FY 2007-2011 about 1 percent higher with this proposal than without it.

***Decision*:** Assuming the proposed contracts are executed, BPA's customers will see a 6 percent decrease in rates from what they would otherwise be during the FY 2005-2006 period and a possible 1 percent increase in the FY 2007-2011 period.

***Issue 10*:** *What consideration does Avista, Idaho Power, Portland General and NorthWestern provide to BPA for their proposed amendments?*

Evaluation: BPA's April 16, 2004, letter and this ROD have explained that Avista, Idaho Power, PGE and NorthWestern provide consideration for the amendments in the form of a waiver of the remaining dollars they deferred under the FY 2003 Deferral Agreements. This amounts to a total of approximately $3.5 million for all four investor-owned utilities.

BPA believes this is adequate consideration under the circumstances. If one considers the total contribution from PacifiCorp and Puget as well as the others, there is more than $103 million in reductions in BPA's payments to these utilities, plus more than $100 million deferred into the FY2007-2011 period. BPA believes, in total, this constitutes adequate consideration for offering the proposed contracts. It should be noted, however, that in the event PacifiCorp and/or Puget were to elect not to sign a proposed contract, BPA has informed all of the investor-owned utilities that it will not go forward with the transaction.

Decision: Avista, Idaho Power, PGE and NorthWestern provide consideration for the amendments in the form of a waiver of the $3.5 million remaining of amounts deferred under the FY 2003 Deferral. This amount, when taken together with the amounts contributed by PacifiCorp and Puget, provides sufficient consideration for offering the proposed contracts.

Issue 11: *Whether BPA should provide the investor-owned utilities with power or monetary benefits during the FY 2007-2011 period.*

Comments: ICNU asks why BPA elected to provide the investor-owned utilities with only monetary benefits in the FY 2007-2011 period.

Evaluation: ICNU seeks an explanation for why BPA is electing to provide the investor-owned utilities monetary benefits as opposed to power deliveries. As previously explained, BPA elects to provide only monetary benefits under the proposed contracts for the FY 2007-2011 period. Given BPA's current load-resource balance, BPA believes it is reasonable to reduce its overall risk in the market by making this decision. Electing to provide only monetary benefits allows BPA to reduce the amount of power it must purchase in the wholesale market to augment BPA's system. Recent history has shown a good deal of volatility in the price of power on the wholesale market. By reducing the need for BPA to purchase power on the market, it will minimize BPA's exposure to the volatility of the market.

Second, BPA's election also provides assistance to the investor-owned utilities by resolving some uncertainty regarding their resource needs during the FY 2007-2011 period. By providing notice more than a year prior to the time BPA must make the election, the investor-owned utilities are better positioned to make resource-planning decisions.

Decision: Providing monetary benefits as opposed to power allows BPA to minimize its exposure to making purchases in the volatile wholesale market and contributes to investor-owned utility resource planning.

Issue 12: *What is the basis for BPA using a mark-to-market methodology along with the caps and floors in calculating monetary benefits?*

Comments: ICNU asks why BPA decided to use a mark-to-market methodology to determine the FBPF, as well as caps and floors. As noted earlier in this ROD, BPA and the investor-owned utilities both sought to bring some transparency to the determination of the FBPF. The investor-owned utilities viewed establishing the market price in a BPA rate case as an opportunity ripe for manipulation. They believed that pressures on the Administrator to reduce costs could result in a very conservative determination in a rate case of the market priced used for FBPF, thereby reducing the level of the investor-owned utilities' benefits.

To address this concern, BPA proposed an independent market price survey. BPA viewed using the independent price survey from a list of EDPs over a multi-month period as a means of providing the desired transparency and at the same time providing a similar mechanism for determining the FBPF.

The proposed contracts also hedge BPA's exposure to the level of investor-owned-utility benefits. When BPA originally agreed to provide some power deliveries to the investor-owned-utilities as part of the Subscription Strategy, the power deliveries were seen as a hedge against the possibility that the financial portion of the benefits would become higher than anticipated. Unfortunately, the power deliveries did not work to hedge BPA exposure. At the time of the Subscription Strategy, BPA envisioned a manageable level of market purchases in order to meet its demand. However, as events unfolded, BPA found itself in a position that required it to make a significantly greater level of purchases to augment the Federal system to meet its load obligations. This fact undermined the hedging effect that power deliveries would have had at the time of the Subscription Strategy. The hedging strategy was further undermined due to the fact that many of these purchases were made at a time of unprecedented high wholesale market prices. As a consequence, the hedging effect of the power sales to the investor-owned-utilities did not materialize as planned.

The proposed agreements do two things to attempt to correct this problem. First, BPA is electing not to provide any power deliveries. This allows BPA to minimize its exposure to the wholesale market. Second, the mark-to-market methodology is collared by a cap and floor. The cap on the on the monetary benefits further ensures that BPA is not exposed to unanticipated benefit levels for the investor-owned-utilities. The floor, conversely, represents a trade-off for obtaining the cap on benefit levels. Together however, the cap and floor bound the level of investor-owned-utility benefits at levels BPA originally anticipated.

Decision: BPA believes the mark-to-market methodology provides the desired transparency that, taken together with the caps and floors, provide BPA a hedge against exposure to the level of investor-owned utility benefits. These elements, together with the decision to provide only monetary benefits, provide BPA with a reasonable balance.

Issue 13: *Whether it is appropriate to offer the proposed contracts without requiring all other parties to waive their legal claims challenging BPA's provision of benefits to the investor-owned utilities.*

Comments: ICNU questions the wisdom of providing the proposed contracts without obtaining agreements from public power to dismiss the pending litigation challenging the provision of these benefits. NRU viewed the decision to disconnect dismissal of litigation and the decision to offer the proposed contracts as positive. In NRU's view, this decision allowed the cases to continue in a timely manner and yet provide the desired rate relief.

Evaluation: BPA believes that certain public power litigants are unwilling to dismiss their current legal claims. Attempting to require them to do so would likely be fruitless. BPA's continuing goal is to find ways of achieving near-term rate relief for BPA's customers. The consideration provided by the investor-owned utilities in return for the mark-to-market methodology, along with the other aspects of the proposed contracts, was a way to achieve this objective without the need to require parties to dismiss litigation. BPA views this matter much the same as NRU, namely, that the offer of the proposed contracts achieves needed rate relief and allows resolution of other issues before the court.

Decision: It is not necessary to require parties to forego legal claims in order to establish the rate relief provided by the proposed contracts.

Issue 14: *Whether the proposed contracts establish a precedent for post-2011 service to the investor-owned utilities.*

Comments: ICNU asks whether the proposed contracts establish any precedent for the provision of benefits to the residential and small farm consumers of regional investor-owned utilities after FY 2011. NRU states that its support for the proposed contracts is conditioned upon assurances that BPA will not rely on them to determine benefits for the investor-owned utilities beyond FY 2011.

Evaluation: The proposed contracts are not intended to provide any precedent regarding the manner and method by which BPA will provide Federal benefits to the residential and small farm customers of regional investor-owned utilities for the post-2011 period. Such benefits will be established in a separate proceeding.

Decision: The proposed contracts do not establish a precedent for post-2011 service to the investor-owned utilities.

Issue 15: *Whether it is appropriate for BPA to determine investor-owned utility benefits outside a BPA rate case.*

Comments: Alcoa asks whether it is appropriate to determine investor-owned utility benefits outside of a BPA rate case.

Evaluation: BPA has never established investor-owned utility benefits in a BPA rate case. Rather, such benefits are determined outside BPA's rate cases and BPA's rate cases simply forecast the projected amount of investor-owned utility benefits for purposes of establishing rates. The proposed contracts substitute a mark-to-market methodology for a forward price forecast from BPA's rate case. Debate over the appropriate level of the RL rate, however, will still occur in BPA's rate cases.

BPA believes the mark-to-market methodology represents a reasonable alternative to a BPA rate case forecast because it provides a level of transparency not necessarily available with a rate case forecast. Additionally, the annual calculation of the price forecast will allow investor-owned-utility benefits to be more consistent with the level of benefits BPA provides its other customers. Under the existing arrangement, benefit levels are based upon a market price forecast for the rate period. As recent events have shown, a rate case forecast can deviate considerably from actual market prices experienced during the period. The difference between the rate case forecast and actual market prices has contributed to a sense of frustration among some customers that the benefits from the Federal system are not equitably shared. Using a market survey will help to address this concern.

Decision: It is appropriate to use a mark-to-market methodology in calculating the FBPF.

Issue 16: *Whether the proposed contracts should be modified to clarify that the Committee can act only through a unanimous vote, and to avoid the suggestion that there are two separate categories of Committee actions.*

Comments: PacifiCorp and Puget jointly submitted a proposed change to the wording of the proposed contracts. The proposed changes were not intended to change the substance or meaning of any section, but rather to clarify the intent of the parties. The proposed changes are as follows:

1. Section 3(b) of the Independent Methodology should be clarified to help ensure that section 3(b) is not misread to permit the Committee to act with less than unanimous vote and more clearly reflect the intent of the parties that the appointed representatives to the Committee act through unanimous vote only.

2. Delete the words "and determinations" from section 3(c) of the Independent Methodology to avoid the erroneous suggestion that there are two separate categories of Committee actions, (i)"actions" and (ii) "determinations."

Evaluation: The Committee referred to by PacifiCorp and Puget is a group comprised of one BPA representative, one PNW IOU representative, and one PNW Public representative. The primary purpose of the Committee is to select a list of eligible EDPs for the QTP to survey for the mark-to-market methodology. BPA believes that the proposed changes reflect the intent of the parties and clarifies the current language. It was the intent that the Committee act through a unanimous vote and the current language in the contract could be misread to imply otherwise. The proposed changes will resolve questions that may arise in the future regarding the intent of the contract. BPA will make these changes before offering the proposed contracts to the region's investor-owned-utilities.

Decision: Proposed changes, to clarify that the Committee acts through unanimous vote only and that that there is a single category of Committee actions, are reasonable and help clarify the intent of the parties.

CONCLUSION

The proposed contracts for the region's investor-owned utilities provide for the deferral of the reduction-of-risk discount to FY 2007-2011. In addition, half of the reduction-of-risk discount, approximately $100 million, is waived in return for the offer of the proposed contracts. These actions will lead to a total reduction in BPA's revenue requirement in the current rate period of approximately $200 million. Such a reduction will result in a significant reduction in rates (through the LB CRAC) in the current rate period, which will provide a benefit to the Pacific Northwest region during troubled economic times.

In addition, the elimination of possible power deliveries and the provision of only monetary benefits to the investor-owned-utilities in the FY 2007-2011 period will reduce the need for BPA to acquire additional power supplies from the wholesale power market. This will reduce BPA's reliance on the unpredictable and volatile wholesale power market, which should enhance the stability of BPA's rates.

I have reviewed and evaluated the proposed mark-to-market methodology, cap, floor, and extended period for the pass-through of benefits to residential and small farm consumers. These modifications provide necessary transparency as well as a fair and independent system for determining the level and nature of investor-owned-utility benefits.

I have also reviewed the proposed changes to the Subscription Strategy and find that these are reasonable and proper under the circumstances.

I have reviewed and evaluated the record compiled by BPA on the proposed contracts. Based upon the record, the reasoning contained therein, and all requirements of law, I hereby offer the proposed contracts and other related documents and make the changes to the Subscription Strategy.

Issued at Portland, Oregon, this 25th day of May, 2004.

Stephen J. Wright
Administrator and Chief Executive Officer

Bonneville Power Administration

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Bonneville Power Administration
Power Business Line

2002 Supplemental Power Rate Proposal Administrator's Final Record of Decision

WP-02-A-09

June 2001

BONNEVILLE
POWER ADMINISTRATION

5.0 RATE CASE MARKET PRICE FORECAST FOR INVESTOR-OWNED UTILITIES' RESIDENTIAL EXCHANGE PROGRAM SETTLEMENTS

5.1 Introduction

In BPA's "Residential Exchange Program (REP) Settlement Agreements With Pacific Northwest Investor-Owned Utilities (IOUs), Administrator's Record of Decision (ROD), October 2000" (REP Settlement ROD), the Administrator decided to offer REP Settlement Agreements to regional IOUs. These Agreements were subsequently executed by BPA and the regional IOUs. BPA's REP Settlement Agreements with regional IOUs provide two types of benefits to the IOUs' residential and small farm consumers: (1) actual power sales at the Residential Load (RL) rate or Priority Firm Power (PF) Exchange Subscription rate; and (2) monetary benefits based on the difference between the RL (or PF Exchange Subscription) rate and BPA's rate case five-year flat block price forecast. The establishment of BPA's five-year flat block market forecast is therefore an issue in BPA's WP-02 rate case.

5.2 Rate Case Market Price Forecast for Investor-Owned Utilities' Residential Exchange Program Settlements

Issue

Whether BPA has established an appropriate price for its rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlement Agreements.

Parties' Positions

The IOUs (Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc.) argue that $38/megawatthour (MWh) is an appropriate price to use as the rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlements. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2-5.

Springfield Utility Board (SUB) argues that BPA proposes to increase the IOUs' financial REP Settlement Agreement benefits by using a $38/MWh forecast instead of the $28.10/MWh forecast used in BPA's May 2000 Final Power Rate Proposal (May Proposal), *citing* Doubleday, *et al.*, WP-02-E-BPA-74, at 6-7. SUB Brief, WP-02-B-SP-02; SUB Ex. Brief, WP-02-R-SP-02, at 5-7. SUB argues that this change is inconsistent with BPA's prior May ROD. *Id.*

BPA Staff Position

BPA staff state that $38/MWh is an appropriate price to use as the rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 9.

Evaluation of Positions

To thoroughly understand this issue, it is helpful to review the record that documents the development of the rate case market price forecast that is used in the calculation of monetary benefits under the IOUs' REP Settlements. These REP settlements are described in greater detail in BPA's "Power Subscription Strategy" and in the REP Settlement ROD.

For the purposes of the WP-02 rate case, BPA developed price forecasts to be used in: (1) designing rates; (2) determining surplus revenue; (3) calculating the cash component of the proposed settlement of the REP with regional IOUs; (4) estimating the cost of augmenting the Federal Base System (FBS) with five-year flat-block purchases; and (5) developing BPA's Cost Recovery Adjustment Clause (CRAC) analyses. Doubleday, *et al.*, WP-02-E-BPA-65. BPA's initial five-year flat block price forecast was used for two purposes. *Id.* The first purpose was for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *See* Oliver, *et al.*, WP-02-E-BPA-20, at 3-4. The Power Subscription Strategy, at 8-9, states:

> BPA's strategy is that IOUs may agree to a settlement of the Residential Exchange Program in which they would be able to purchase a specified amount of power under Subscription for their residential and small farm consumers at a rate approximately equivalent to the PF Preference rate.
>
> In Subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of federal power for the 2002–2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is most cost-effective for BPA.
>
> . . . Any cash payment will reflect the difference between the market price of power forecast in the rate case and the rate used to make such subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period. . . .

BPA staff stated that it was necessary to develop a separate forecast for this purpose. *See* Oliver, *et al.*, WP-02-E-BPA-20. The second purpose of BPA's initial forecast was to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* at 3.

BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year flat block purchases. *See* Oliver, *et al.*, WP-02-E-BPA-20, at 3. BPA used actual market experience to derive a price estimate of five-year flat block purchases and confirmed this estimate by using a derivation of BPA's Marginal Cost Analysis (MCA), market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.* In summary, based on recent market experience and confirmed by a variety of information using a derivation of the MCA, financial swap quotes, and a reasonable extrapolation of current prices using historical and forecasted assessments of price escalation, BPA determined that a price of $28.10/MWh reasonably reflected the average long-term purchase price for five-year flat block energy. *Id.* at 7.

In BPA's 2002 Amended Power Rate Proposal (Amended Proposal), BPA staff again noted that BPA's REP Settlement Agreements provide two types of benefits to the residential and small farm consumers of regional IOUs: (1) actual power sales at the RL rate or PF Exchange Subscription rate; and (2) monetary benefits based on the difference between the RL (or PF Exchange Subscription) rate and BPA's rate case five-year flat block price forecast. Doubleday, *et al.*, WP-02-E-BPA-65, at 4. BPA proposed that its RL and PF Exchange Subscription rates for power sales to IOUs should be subject to CRACs. *Id.* BPA's proposed CRACs would affect the effective level of the RL and PF Exchange Subscription rates and, therefore, the cost of the power sale portion of the REP Settlements. *Id.* In addition, the monetary portion of the REP Settlement benefits would be calculated using the difference between the RL (or PF Exchange Subscription) rate and BPA's Amended Proposal for a five-year flat block price forecast, which differed from the five-year flat block price forecast used in BPA's May Proposal. *Id.* In BPA's Amended Proposal, BPA staff proposed to use the risk-adjusted average market price forecast for the Fiscal Year (FY) 2002-2006 rate period that was developed in BPA's May Proposal. *Id.* The risk-adjusted average market price forecast is the average spot market price for all hours of the year estimated by AURORA to quantify BPA's operating risk in Risk Analysis Model (RiskMod) for the Risk Analysis Study. *Id.* The risk-adjusted average market price forecast in BPA's May Proposal was $34.1/MWh. *Id.,* citing Conger, *et al.*, WP-02-E-BPA-63.

BPA staff proposed this change in the Amended Proposal for some of the same reasons it proposed to amend the May Proposal. Doubleday, *et al.*, WP-02-E-BPA-65, at 5. First, BPA's load obligations had increased substantially over earlier rate case forecasts on which BPA's May Proposal market price forecast, in part, was based. *Id.* The increase in load obligations would make it difficult for BPA to meet all its augmentation needs with five-year flat block purchases made prior to the start of the rate period. *Id.* Since a substantial portion of BPA's purchase requirements may be met with spot market or short-term forward purchases, it was more reasonable to use BPA's rate case risk-adjusted average price forecast as the five-year forward flat block forecast of market prices for calculating monetary settlement benefits. *Id.* In addition, there was a realistic expectation that market prices could be higher than anticipated in the May Proposal. *Id.* Therefore, changing from the prior market price forecast of $28.10/MWh to BPA's proposed $34.1/MWh rate case market forecast was a reasonable step to meet the original intent of the Power Subscription Strategy. *Id.* The $34.1/MWh rate also would have more accurately reflected BPA's purchase power costs for its entire amount of five-year flat blocks of power for the rate period. *Id.*

The five-year flat block forecast was designed: (1) to capture the costs of making purchases prior to the rate period for terms longer than one year to augment the FBS; and (2) to estimate the cost of advance purchases of five-year flat block energy by the IOUs. *Id.*, citing Oliver, *et al.*, WP-02-E-BPA-20, at 3. BPA anticipated that actual purchases of power would be made above and below the forecast price and that a portion of the energy would be provided from surplus energy and not energy purchased in advance of the rate period. Doubleday, *et al.*, WP-02-E-BPA-65, at 5; Doubleday, *et al.*, WP-02-E-BPA-65(E2).

At the time of the Amended Proposal, BPA staff felt that the risk-adjusted average market price forecast of $34.1/MWh was reasonable for three reasons. *Id.* at 6. First, while then-current forecasts of the average price of the marginal MWh for the five-year rate period, purchased during the five-year rate period, might average in the $40 to $50/MWh range, BPA had already purchased over 700 average megawatts (aMW) of power at prices at or below $28.10/MWh. *Id.* The then-current estimate of the amount of power BPA would purchase during the five-year rate period was 3,305 aMW (1,745 aMW of BPA purchases for forecasted loads plus 1,560 aMW of additional purchases for non-forecasted loads). *Id.* BPA expected to purchase the 3,305 aMW per year at an average cost that is below the marginal cost indicated by the then-current market price forecasts used in establishing BPA's new proposed CRACs. *Id.* Second, the monetary benefits are provided for 900 aMW of IOU RL service under the REP Settlements. *Id.* BPA staff stated that the IOUs must make purchases to serve these 900 aMW of RL service during the five-year rate period. *Id.* BPA staff argued that the IOUs had known about the need to purchase additional resources to serve these loads since December 1998 and had likely made some or all of those purchases. *Id.* BPA staff argued that since the five-year forward flat block forecast was designed to forecast the market price of these forward purchases, it was reasonable to conclude that some or all of the IOU purchases were made prior to the recent increase in market prices. *Id.*

Third, current estimates of the market price would not be an appropriate forecast to use for purchases that cover a range of market conditions and purchases. *Id.* As discussed in the policy testimony of Burns and Berwager, WP-02-E-BPA-62, BPA had addressed the impact of the current price volatility for the REP Settlements by proposing to exempt the RL and PF Exchange Subscription rates from the application of the proposed CRACs when such rates were used for calculating monetary benefits. *Id.* at 6-7. BPA staff noted that it was more appropriate to eliminate the cost impacts of current price volatility from the rates used to calculate the monetary benefits rather than redoing a forecast at the end of the forecast period, citing Burns and Berwager, WP-02-E-BPA-62. *Id.* at 7. BPA's Amended Proposal proposed the use of a forecast made during its rate case as BPA's five-year forward flat block forecast. *Id.*

In its 2002 Supplemental Power Rate Proposal (Supplemental Proposal) direct testimony, BPA staff built upon their Amended Proposal. BPA staff noted that BPA had made a policy decision to adjust its forward flat block forecast from $34.1/MWh to $38/MWh. Doubleday, *et al.*, WP-02-E-BPA-74. This issue is addressed in the policy testimony of Burns and Berwager, WP-02-E-BPA-70. This adjustment was made for a number of reasons. Doubleday, *et al.*, WP-02-E-BPA-74. In summary, BPA staff recently conducted settlement discussions with all interested parties in BPA's WP-02 rate case. *Id.*, citing Burns and Berwager, WP-02-E-BPA-70. A large number of those parties proposed a partial settlement of many rate case issues. *Id.* One element of that proposal was that the forecast used to calculate the financial benefits under the REP Settlements should be $38/MWh. *Id.* When viewed in the context of the Partial Stipulation and Settlement Agreement, BPA staff elected to make this adjustment, also noting that prices had increased since the time of BPA's Amended Proposal. *Id.* While BPA staff did not expect current prices to continue for the five-year period of the forward flat block forecast, BPA staff believed, viewed in the context of the total settlement proposal, that current high market prices lasting through the first 6 to 18 months of the forecast period justified an increase in the forecast price to $38/MWh. *Id.*

In addition to the issue of the rate case market price forecast, there is another issue that affects prospective REP Settlement benefits. As originally proposed in BPA's Amended Proposal in the policy testimony of Burns and Berwager, WP-02-E-BPA-62, BPA staff proposed that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits for the 900 aMW designated as monetary benefits in the REP Settlements, should be exempt from the proposed Load-Based (LB) and Financial-Based (FB) CRACs. *Id.* BPA staff argued that REP Settlement Power (1,000 aMW) that is converted into monetary benefits under the REP Settlement, however, should be subject to the LB CRAC and FB CRAC, in the calculation of such new monetary benefits. *Id.* The LB CRAC is designed to recover the cost of serving load not forecasted in the May Proposal. *Id.* The FB CRAC is designed to recover higher than expected costs, including increased market price purchases of power. *Id.* BPA chose to protect the 900 aMW designated as monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed LB and FB CRACs instead of changing the forecast of five-year forward flat block purchases. *Id.* Since the amount of the monetary portion is fixed, it was reasonable to exclude the load served by the monetary benefits from the possible rate volatility introduced by application of the proposed LB and FB CRACs. *Id.* BPA staff's proposal provides a greater amount of certainty to the monetary benefit calculation. *Id.*

The foregoing summarizes BPA staff's positions in this proceeding. The IOUs agreed with BPA staff on certain issues, but disagreed with BPA staff on other issues, as noted below. In their initial brief, the IOUs note that within months of issuing the May ROD, BPA recognized that unpredicted events had resulted in an extremely volatile market with prices far higher (particularly in the first two years) than its five-year flat block forecast and increased demand. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2. This recognition led to the reopening of this proceeding in order to redesign BPA's risk mitigation tools to handle unforeseen costs and make other appropriate adjustments to its rate proposal. *Id.* The IOUs also note that because of the extreme volatility of the current wholesale electricity market, BPA identified and revised its estimated five-year flat prices several times during this phase of the proceeding. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2-3, citing Conger, *et al.*, WP-02-E-BPA-63, at 14; BPA's Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-18; Lefler, *et al.*, WP-02-E-BPA-73, at 38; and Doubleday, *et al.*, WP-02-E-BPA-74, at 7. The IOUs note that this extreme volatility led the Joint Customers Group (JCG) to propose cost-recovery adjustments every six-months with twice yearly true-ups to the actual cost of purchasing augmentation power. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 3. This proposal was incorporated into the Partial Stipulation and Settlement Agreement. *Id.*, citing Burns and Berwager, WP-02-E-BPA-70, at 4-14.

The IOUs argue that whether the $38/MWh price used to calculate the financial portion of benefits for the IOUs' residential customers constitutes a reasonable five-year flat block forecast as contemplated by the Subscription Strategy is not a rate case issue subject to Federal Energy Regulatory Commission (FERC) review. *Id.* at 4. The IOUs argue that the decision BPA must make is whether using the stipulated $38/MWh price is arbitrary or capricious based on the rate case record. *Id.* It is not arbitrary or capricious to select $38/MWh where the vast majority of BPA's customers, the four state commissions, and BPA staff have agreed (only as part of a broader settlement) that it is an acceptable proxy for a five-year flat block forecast. *Id.*, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 16-18.

The IOUs argue that BPA and the IOUs recognize that the 28.10 mill forecast is not an accurate five-year flat block forecast for 900 aMW of power to be delivered commencing October 1, 2001, citing BPA's Supplemental Study, WP-02-BPA-69, at 5-18, and Brattebo, *et al.*, WP-02-E-JCG-02, at 21. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 3. The IOUs note that BPA staff, mindful of the Administrator's commitment to deliver the financial equivalent of 900 aMW of power to the IOUs' residential customers, yet desirous of lowering BPA's costs in the face of a massive rate increase, argued that the five-year flat block forecast need not be adjusted to reflect today's prices in order to provide the companies with the financial equivalent of 900 aMW. *Id.* Rather, according to BPA staff, the Administrator should exempt these financial benefits from the LB and FB CRACs and assume that the IOUs purchased some portion of the 900 aMW between December 1998 (when BPA began purchasing some portion of its anticipated augmentation needs) and December 2000 (when BPA filed its Amended Proposal). *Id.* The IOUs agree that exempting their residential customers' financial benefits from the LB and FB CRACs is necessary because the Partial Stipulation and Settlement Agreement, in the IOUs' view, will not provide these customers with the financial equivalent of 900 aMW at the proposed $38/MWh price, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 11. *Id.* The IOUs argue, however, that the Administrator need not, and should not, assume that the IOUs had purchased some portion of the 900 aMW of power before the end of 2000 in order to justify the reasonableness of the $38/MWh price for the purpose of calculating the financial benefits for the IOUs' residential customers. *Id.* The IOUs argue that, as the JCG explained, BPA staff's assumption is wrong, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 16-17. *Id.* at 3. Also, the IOUs argue that it is unnecessary for the Administrator to make such a finding. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 4.

BPA agrees with the IOUs that BPA must determine whether using the stipulated $38/MWh price is arbitrary or capricious based on the rate case record. BPA agrees that it is not arbitrary or capricious to select $38/MWh where the vast majority of BPA's customers, the four state commissions, and BPA staff have agreed (only as part of a broader settlement) that it is an acceptable proxy for a five-year flat block forecast. After review of the record, BPA agrees with the IOUs in finding that it is unnecessary to assume that the IOUs had purchased some portion of the 900 aMW of power before the end of 2000 in order to justify the reasonableness of the $38/MWh price for the purpose of calculating the financial benefits for the IOUs' residential customers. The record shows that the members of the JCG and BPA staff support the adoption of $38/MWh as the price forecast to be used in calculating financial benefits under the REP settlements. *See* Doubleday, *et al.*, WP-02-E-BPA-74. The record shows that BPA staff also agree with the JCG that there is currently a broad range of market forecasts in a volatile and changing market and that $38/MWh, which is reflected in the Partial Stipulation and Settlement Agreement, represents a reasonable forecast to be used in the determination of financial benefits under the REP settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 9. While the record shows support for the $38/MWh forecast in a volatile and changing market, the record lacks any evidence demonstrating that the $38/MWh forecast is inappropriate for any substantive reason. While some parties do not appear to like the result of the adoption of a $38/MWh forecast, which increases the amount of monetary benefits provided to IOUs under the REP Settlement Agreements, this does not show any substantive deficiency in the forecast itself. Doubleday, *et al.*, WP-02-E-BPA-78, at 4-5. The forecast is simply an element that is developed in BPA's rate case and inserted into current REP Settlement Agreements, which were previously established in separate public processes. As discussed in greater detail below, BPA does not determine the reasonableness of the REP Settlement Agreements in the rate case. *Id.* at 4-8.

SUB argues that BPA proposes to increase the IOUs' financial REP Settlement Agreement benefits by using a $38/MWh forecast instead of the $28.10/MWh forecast used in BPA's May Proposal, citing Doubleday, *et al.*, WP-02-E-BPA-74, at 6-7. SUB Brief, WP-02-B-SP-02. SUB argues that this change is inconsistent with BPA's prior May ROD. *Id.* While BPA's forecast is different from that in BPA's May Proposal, BPA is not precluded from revising the rate case market price forecast used to calculate monetary benefits under the IOUs' REP Settlement Agreements. It should be recalled that the purpose of the forecast is for the calculation of monetary settlement benefits, that is, the forecast is part of a formula to determine the proper amount of benefits that should be provided to the IOUs for a settlement of their participation in the REP. This is a discrete purpose that was originally envisioned in BPA's Power Subscription Strategy and for which BPA must develop an appropriate rate case market price forecast. BPA's revision to the forecast is being conducted in accordance with section 7(i) of the Northwest Power Act, also as provided in BPA's Power Subscription Strategy. 16 U.S.C. § 839e(i). BPA staff previously explained why the $28.10/MWh forecast was changed. *See, e.g.*, Burns and Berwager, WP-02-E-BPA-62, at 14; Doubleday, *et al.*, WP-02-E-BPA-65; Burns and Berwager, WP-02-E-BPA-70, at 11; Doubleday, *et al.*, WP-02-E-BPA-78, at 9. BPA therefore properly changed its rate case market price forecast to $38/MWh from BPA's May Proposal.

In its brief on exceptions, SUB states that in one section of the 2002 Draft Supplemental Record of Decision (Draft Supplemental ROD), BPA bases its arguments regarding the Industrial Firm Power Targeted Adjustment Charge (IPTAC) rate on a limited scope of issues in this proceeding, while in another section of the WP-02 Draft Supplemental ROD, BPA states that it is not precluded from modifying the market price forecast for IOU benefits. SUB Ex. Brief, WP-02-R-SP-02, at 5. SUB argues that this alleged inconsistency should be corrected and the price used to determine IOU financial benefits should not be increased. *Id.* First, it must be noted that while BPA's own proposal may be limited to certain issues, BPA did not limit the scope of issues that could be raised by other parties in this proceeding any differently than BPA did in its May Proposal. BPA's testimony expressly notes that:

> BPA's Amended Proposal does not require that every issue that was debated and decided in the May Proposal be reexamined. Many of those issues are not germane to the cost recovery problem that this amended proceeding has been initiated to address. By the same token, BPA recognizes that the parties may have different views on the issues that are germane or may wish to sponsor their own solution. Accordingly, the scope of this proceeding is limited only to the scope of the first phase of this rate case. *See* 64 Fed. Reg. 44318 (August 13, 1999) and the 2002 Final Power Rate Proposal Administrator's Record of Decision, WP-02-A-02 (May ROD).

Burns and Berwager, WP-02-E-BPA-62, at 3-4. Thus, the scope of this rate proceeding clearly encompasses the rate case market price forecast for the calculation of the IOUs' monetary benefits under the REP Settlement Agreements. The forecast also was expressly raised as an issue at the outset of BPA's Amended and Supplemental Proposals. *See* Doubleday, *et al.*, WP-02-E-BPA-65; Doubleday, *et al.*, WP-02-E-BPA-74. As noted above, BPA staff previously explained why the $28.10/MWh forecast in BPA's May Proposal was changed and why BPA's proposed $38/MWh forecast is appropriate.

In addition, BPA staff did not base their arguments regarding the IPTAC rate on a "limitation of the scope of changes in this proceeding to CRAC redesign and Slice product adjustments." Instead, BPA staff reviewed the issue of proposed changes to the IPTAC rate and concluded, in their opinion, that such changes were inappropriate and that BPA could best address its risk problems through rate mitigation measures and without having to completely develop new rates. BPA did not reject the parties' IPTAC arguments on the basis that they were outside the scope of the rate case.

Decision

BPA has established an appropriate price for its rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlement Agreements.

5.3 Residential Exchange Program Settlement Agreements with Regional Investor-Owned Utilities

Issue

Whether the benefits provided under the REP settlements with regional IOUs are reasonable.

Parties' Positions

The JCG argues that certain parties' allegations that the REP settlement benefits are unreasonable are based on faulty premises and are beyond the scope of the WP-02 rate proceeding. JCG Brief, WP-02-B-JCG-02, at 17-19.

BPA Staff Position

BPA staff note that BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 4.

Evaluation of Positions

The JCG notes that, during the hearing, certain parties argued that the benefits obtained by the IOUs under the REP settlements are, due to changed circumstances, far greater than was intended at the time the settlement was entered into, and that the level of benefits is now unreasonable, citing Schoenbeck and Bliven, WP-02-E-DS-06, at 8-10. JCG Brief, WP-02-B-JCG-02, at 17. The JCG notes that these parties urge BPA to alter the terms of REP settlements, and to reduce the level of benefits being provided. *Id.* The JCG argues that these arguments are based on faulty premises, and should be rejected by the Administrator. *Id.* The predicate for these arguments is a faulty comparison between the benefits that the IOUs might have received under the REP and those being provided under the REP settlements. *Id.* In making this comparison, these parties fail to take into account two salient factors. *Id.*

First, these parties materially underestimate the level of benefits that might have been available to the IOUs under the REP. *Id.* They fail to consider the financial impact of the IOUs being potentially allowed to include such items as income taxes in average system cost (ASC), and the effect of market power purchases on ASC, in their benefit calculations. *Id.*, citing Brattebo, *et al.*, WP-02-E-JCG-03, at 20-23. BPA staff also noted that there are many variables that could substantially increase the value of the traditional REP. Doubleday, *et al.*, WP-02-E-BPA-78, at 2-3. This issue is discussed at great length in BPA's REP Settlement ROD. *Id.*

Second, the parties' arguments fail to recognize that while the escalating price of power on the wholesale market increases the value of the power available to the IOUs under the REP settlements, it also effectively decreases the value of the financial portion of the REP settlements at the same time. JCG Brief, WP-02-B-JCG-02, at 17-18. And since the power deliveries (1,000 aMW) and the financial benefits (900 aMW) are essentially of equal magnitude, the increasing value of the power deliveries is essentially negated by the decreasing value of the financial benefits. *Id.* at 18. These arguments also overlook the benefit of certainty that BPA achieved by entering into the REP settlements. *Id.*

The JCG correctly notes that the remedy sought by these parties, revision of the benefits available under the REP settlements, is beyond the scope of this WP-02 proceeding. JCG Brief, WP-02-B-JCG-02, at 18. BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 4. BPA conducted a separate public involvement process regarding the development and offer of the REP settlements. *Id.*, citing the REP Settlement ROD. The DSIs were among the parties commenting on the proposed settlements in that forum. *Id.* After issuance of the REP Settlement ROD, the REP settlements were executed by BPA and the IOUs in October 2000. *Id.* BPA will not determine the reasonableness of the REP settlements in this forum.

Finally, the JCG correctly notes that issues regarding BPA's Power Subscription Strategy were excluded from the scope of this proceeding in the Federal Register Notice that initiated the WP-02 proceeding. JCG Brief, WP-02-B-JCG-02, at 18, citing 64 Fed. Reg. 44,318-44,323 (1999). These exclusions were reiterated in the Federal Register Notice that commenced the amended phase of the WP-02 rate proceeding. *Id.* This notice stated in part:

> The second area of exclusion concerns decisions made in the Subscription Strategy. The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit decisions that were made in BPA's Subscription Strategy …

Id., citing 65 Fed. Reg 75,275 (2000).

Decision

Parties' allegations regarding the appropriateness of benefits provided under the REP settlements are misplaced. BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements.

10.0 CONCLUSION

As required by law, the adjustment to base rates established and adopted in this ROD has been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and all other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, this adjustment to base rates has been designed to be as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power and to satisfy BPA's other ratemaking obligations. The Hearing Officer has assured that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate the proposed adjustment to base rates in a section 7(i) proceeding pursuant to the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rate increases and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's 2002 final power rate proposal. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the attached General Rate Schedule Provisions as Bonneville Power Administration's 2002 final adjustment to the base power rates proposal. In accordance with Federal Energy Regulatory Commission requirements, 18 C.F.R. section 300.10(g), the Administrator hereby certifies that the Wholesale Power Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this 20th day of June, 2001.

Acting Administrator and Chief Executive Officer

Deputy Secretary Briefing on IOU Rate Reduction Purchases

BPA Rate Reduction Strategy

- **BPA's Internal Rate Reduction Goal was a LBCRAC less than 75% for the first six months and a LBCRAC no higher than 50% in any other period**

- **Initial BPA Strategy Assumed 619 aMW of IOU purchases at $75, (or $40 net), for five years in achieving a LBCRAC for the first six months under 75%**

- **IOU Purchases Were the Only Identified Source of Significant Amounts of 2001, Q4 Energy without approaching marketers or brokers**

- **BPA expected 2001, Q4 market prices to elevate significantly if BPA approached the market with a purchase need over 500 aMW**

BPA Decision Analysis

- **BPA analyzed the impact of 600-700 aMW of IOU Purchases under High, Low, and Current Market Scenarios on May 17**

- **IOU purchases at $38 net met the Rate Reduction Goals under all Market Scenarios**

- **Purchasing from the market instead of the IOUs left a LBCRAC of greater than 75% in the first year even under the Low Market Scenario**

- **The difference in PF rates between the Current Market Scenario and the Low Market Scenario is not more than $3/MWh in 04-06 (Assuming no incidental benefits of the IOU Purchases)**

- **The full rate reduction strategy including IOU purchases results in an average PF rate over the 5-years less than $1/MWh higher than the full rate reduction strategy without IOU purchases under the Low Market Scenario**

Incidental Benefits of IOU Purchases

- **IOU Purchases Collared BPA's Exposure to Market Prices by Purchasing Forward against High Market Prices and Reducing the Effective Price ($38 plus the RL Rate) as BPA's Rates Decrease under Low Market Scenarios**

- **Absent both IOU Purchases, BPA would have had to do deals with both Kaiser and Goldendale to meet the terms of the contingency provisions in IOU and public agency rate reduction contracts.**

- **Puget agreement for 368 aMW was a large amount, concluded discussions started by Puget in November before any interest shown by Pacificorp, and extended settlement of Residential Exchange Program to 10-years for the last IOU in the region.**

- IOU Purchases are $3/MWh less than a comparable purchase from the market based on the IOU agreement to relinquish Dividend Distribution Clause revenues

- A full rate reduction strategy, including IOU purchases, improves BPA's 02 winter reliability outlook

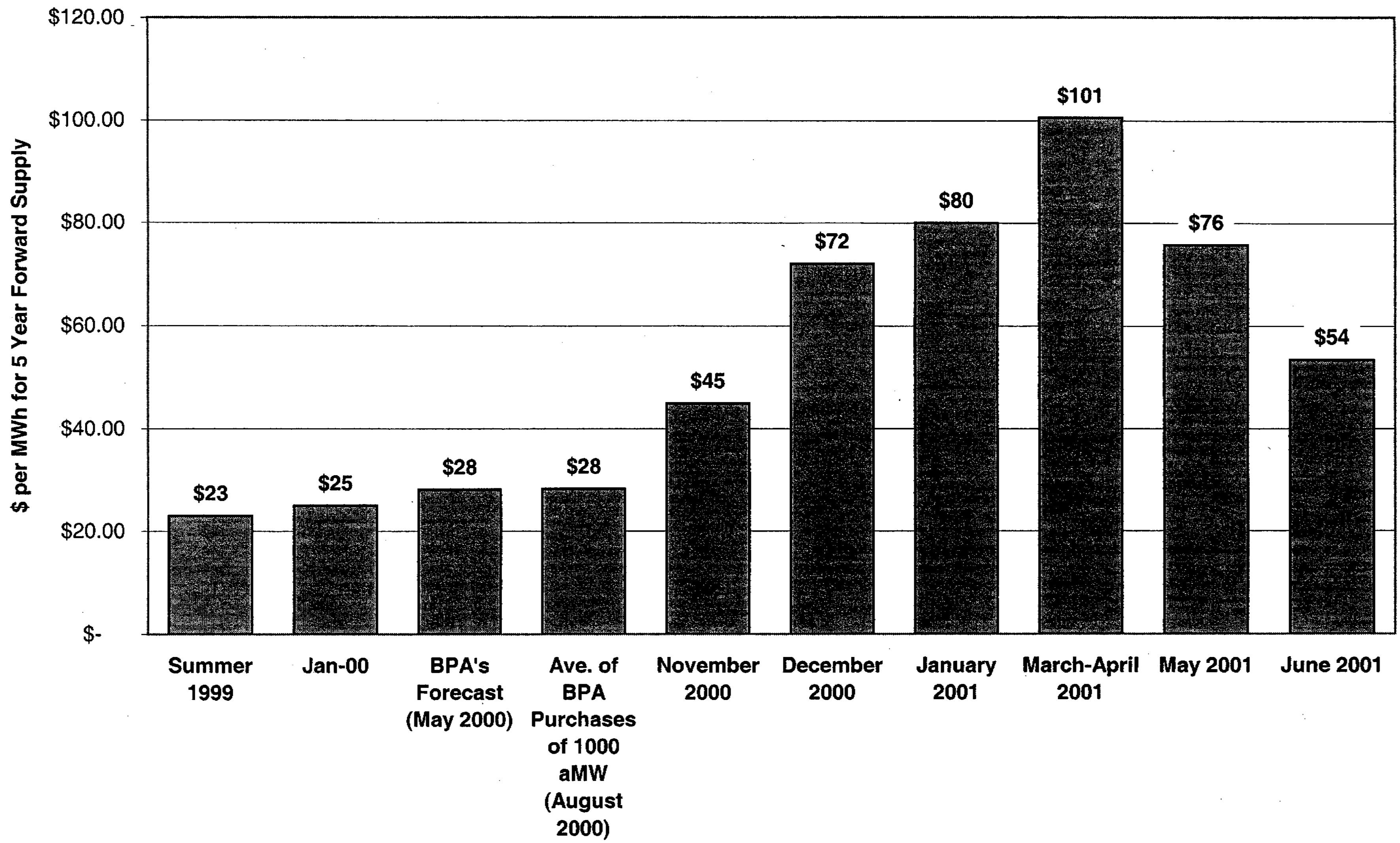
<u>Timing of IOU Purchases</u>

- Pricing agreed with PaciCorp on May 1 and Puget on May 9. Pacificorp was an early adopter signed on May 23. Agreement on final language with Puget on May 31 and signed on June 5.

- Both agreements required IOUs to work with State Commissions

- BPA reached agreement on price with Idaho Power on May 13 but decided not to proceed on June 6 since final language was not done and market dropped significantly from May 31 through June 6.

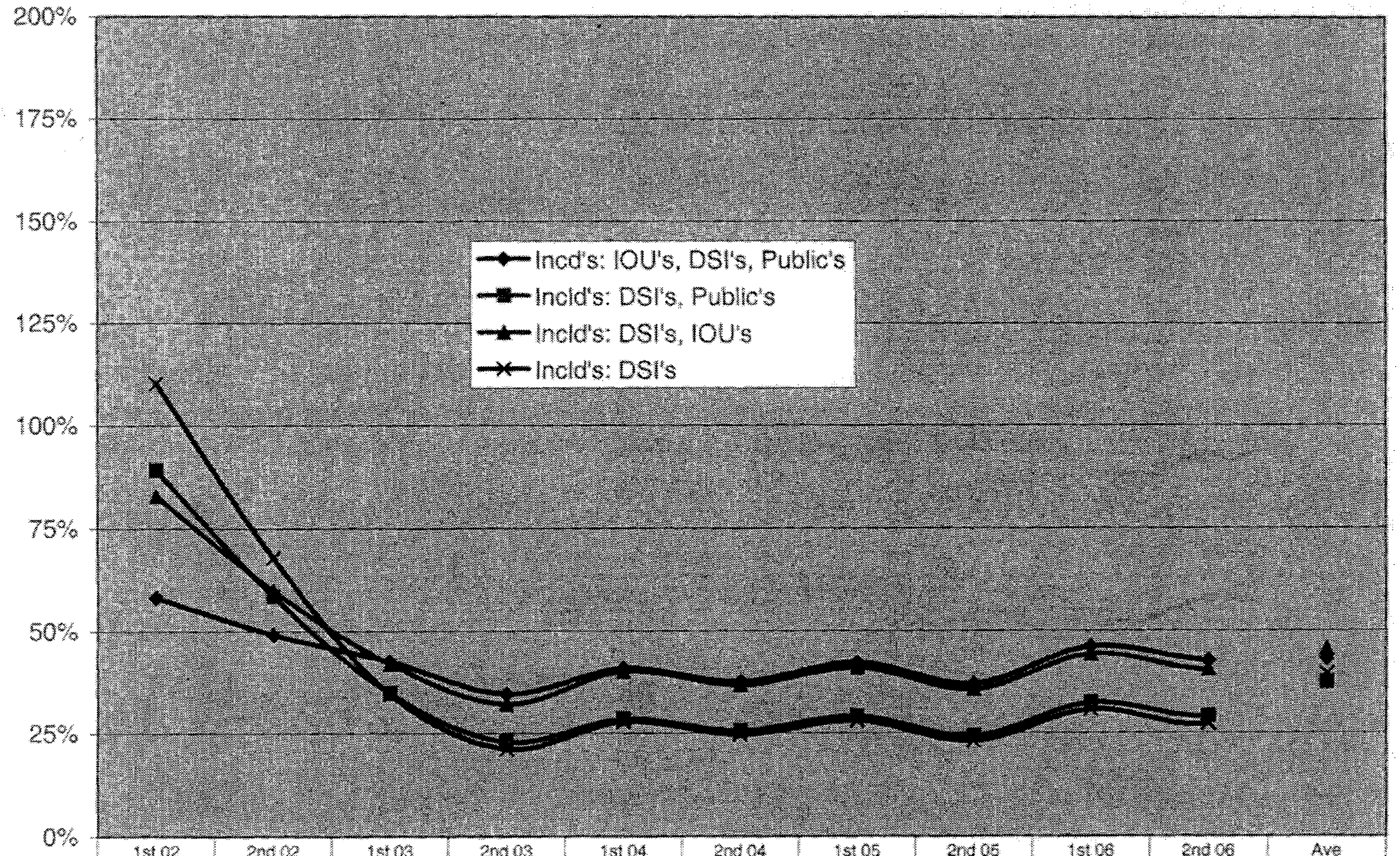
Forward Prices for FY02-FY06 Forward Blocks of Mid C Flat Energy



	$ per MWh for 5 Year Forward Supply
Summer 1999	$ 23.00
Jan-00	$ 25.00
BPA's Forecast (May 2000)	$ 28.10
Ave. of BPA Purchases of 1000 aMW (August 2000)	$ 28.25
November 2000	$ 45.00
December 2000	$ 72.00
January 2001	$ 80.00
March-April 2001	$ 100.59
May 2001	$ 75.68
June 2001	$ 53.50

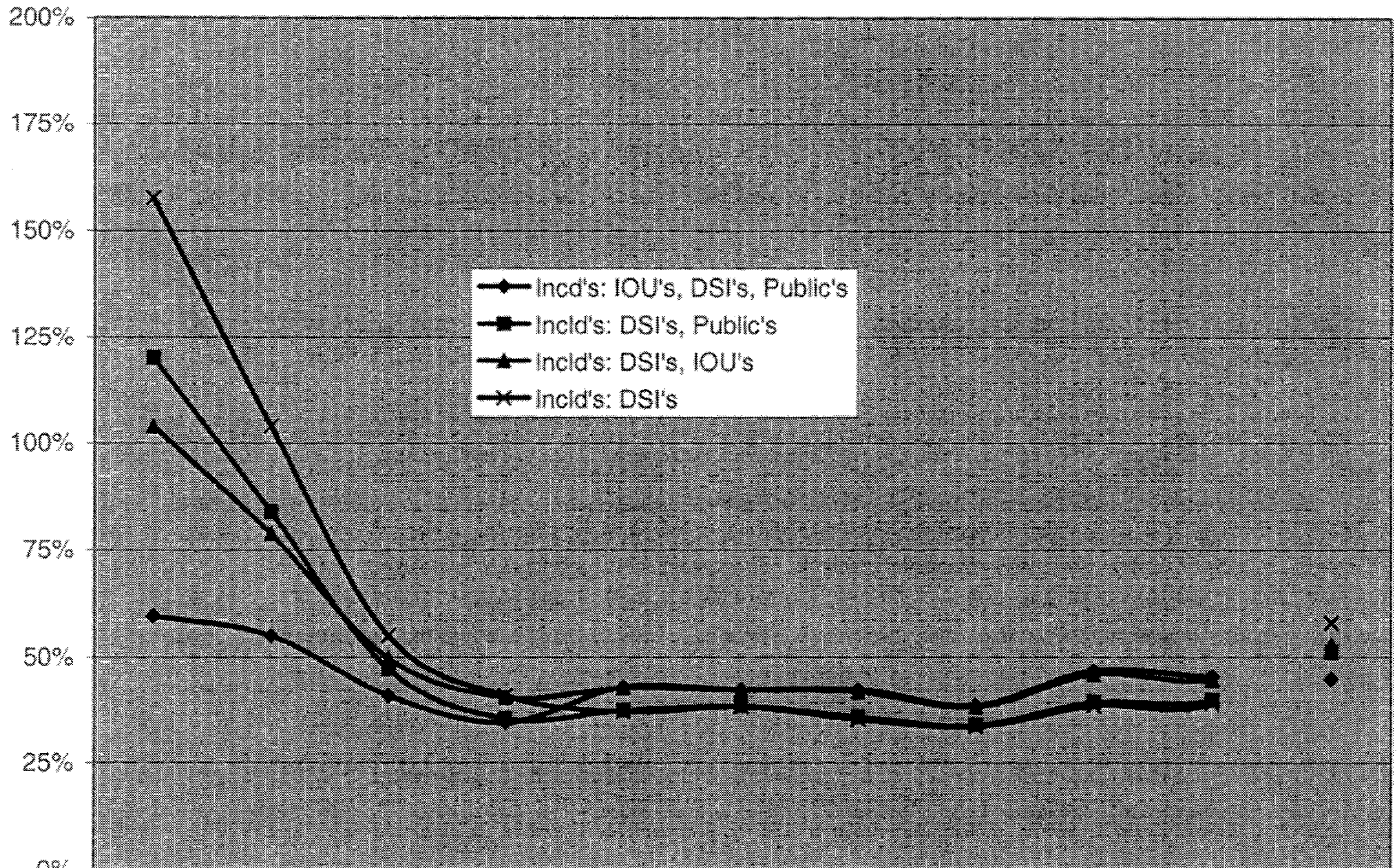
8/1/2000	$ 28.12	
10/5/2000	$ 49.02	
11/15/2000	$ 75.00	Mark to Market
3/20/2001	$ 96.48	Mark to Market
3/28/2001	$ 100.59	Mark to Market
4/18/2001	$ 92.63	Mark to Market
5/8/2001	$ 78.63	Mark to Market
5/15/2001	$ 78.63	Mark to Market
5/21/2001	$ 69.77	Mark to Market
5/30/2001	$ 57.04	Mark to Market
6/4/2001	$ 52.00	Mark to Market

LB CRAC % - Low Market Case



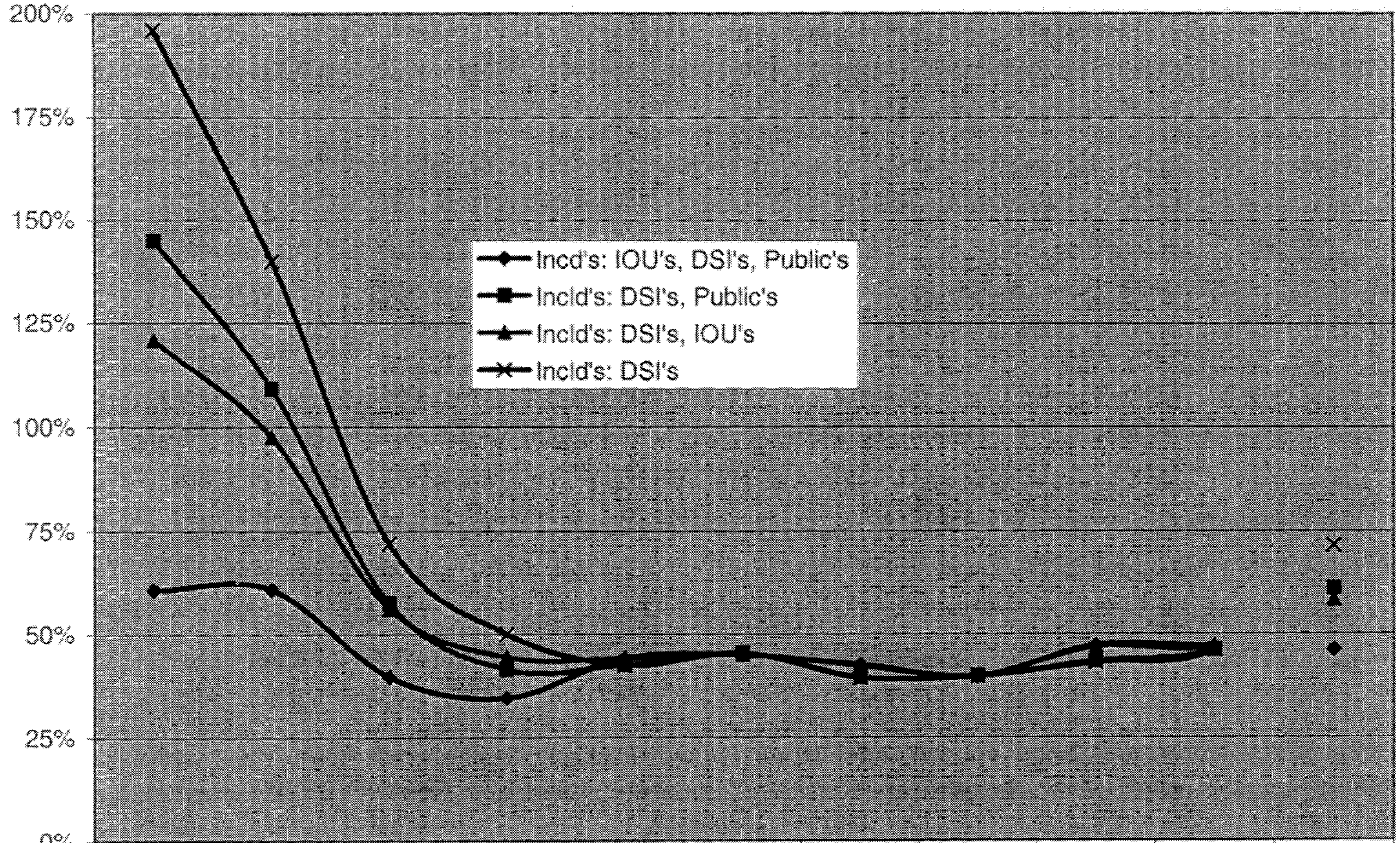
	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's. IOU's, DSI's, Public's	58%	49%	43%	35%	41%	38%	42%	37%	46%	43%	43%
Incld's. DSI's, Public's	89%	59%	35%	23%	28%	25%	29%	24%	32%	29%	37%
Incld's: DSI's, IOU's	83%	60%	42%	32%	40%	37%	41%	36%	44%	41%	45%
Incld's: DSI's	110%	68%	35%	21%	28%	25%	28%	23%	31%	27%	40%

LB CRAC % - Current Market Case



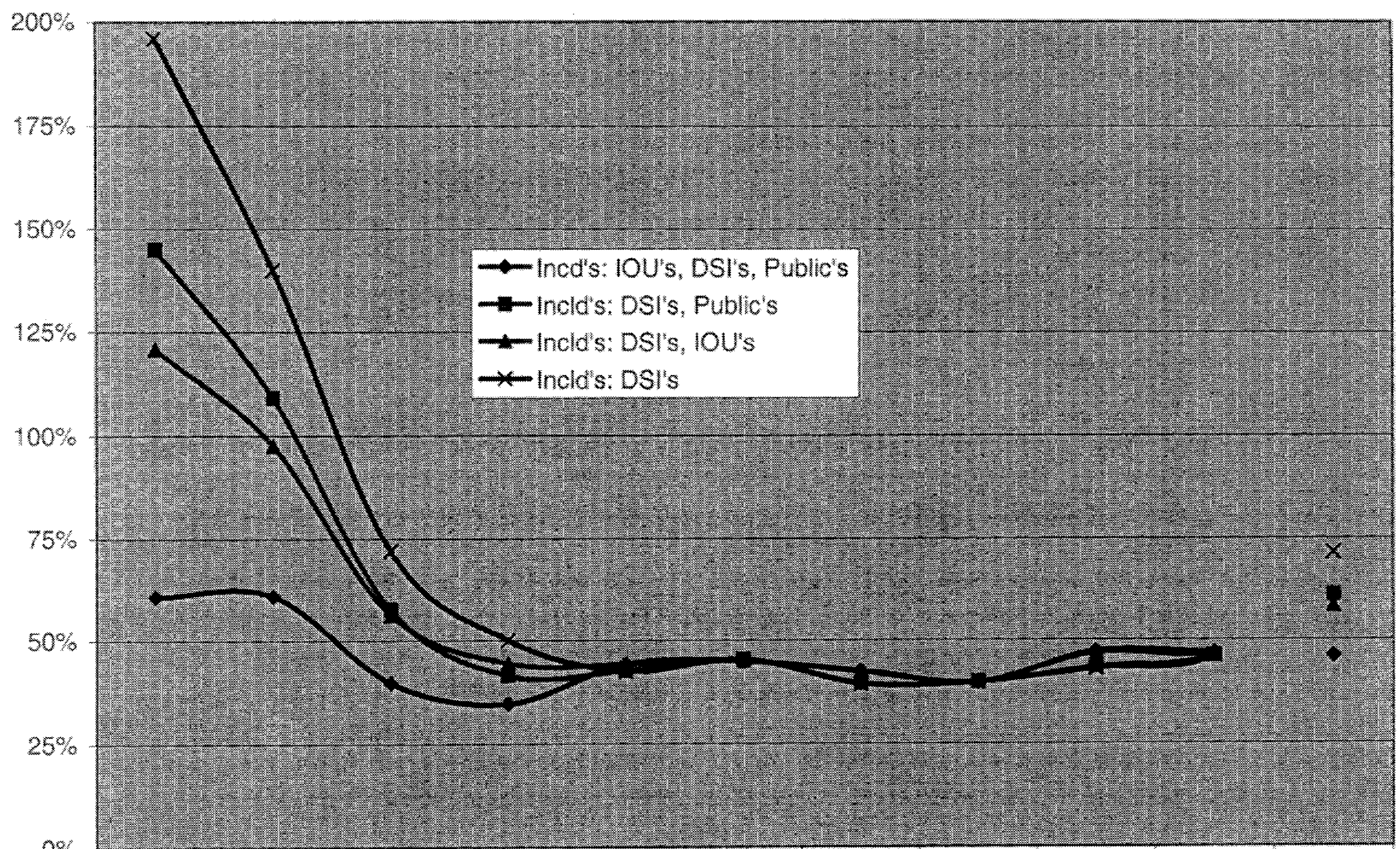
	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	60%	55%	41%	35%	43%	42%	42%	39%	47%	45%	45%
Incld's: DSI's, Public's	120%	84%	47%	36%	37%	38%	36%	34%	39%	40%	51%
Incld's: DSI's, IOU's	104%	79%	50%	40%	43%	42%	42%	38%	46%	45%	53%
Incld's: DSI's	158%	104%	55%	41%	37%	38%	35%	34%	39%	39%	58%

LB CRAC % - High Market Case



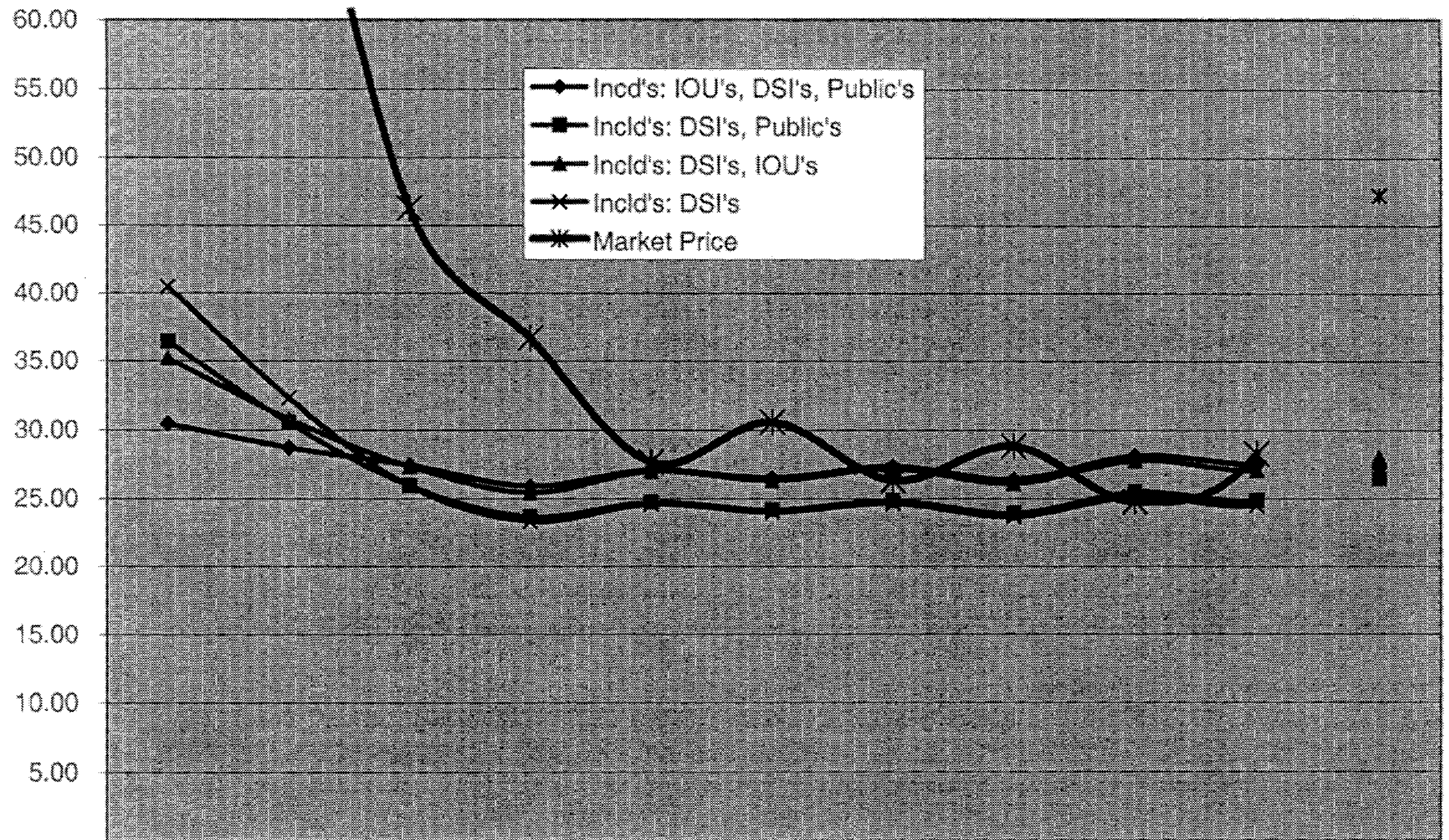
	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	61%	61%	40%	35%	44%	45%	42%	40%	47%	47%	46%
Incld's: DSI's, Public's	145%	109%	58%	41%	43%	45%	40%	40%	43%	46%	61%
Incld's: DSI's, IOU's	121%	98%	56%	44%	44%	45%	42%	40%	47%	47%	58%
Incld's: DSI's	196%	140%	72%	50%	42%	45%	39%	40%	43%	46%	71%

LB CRAC % - High Market Case



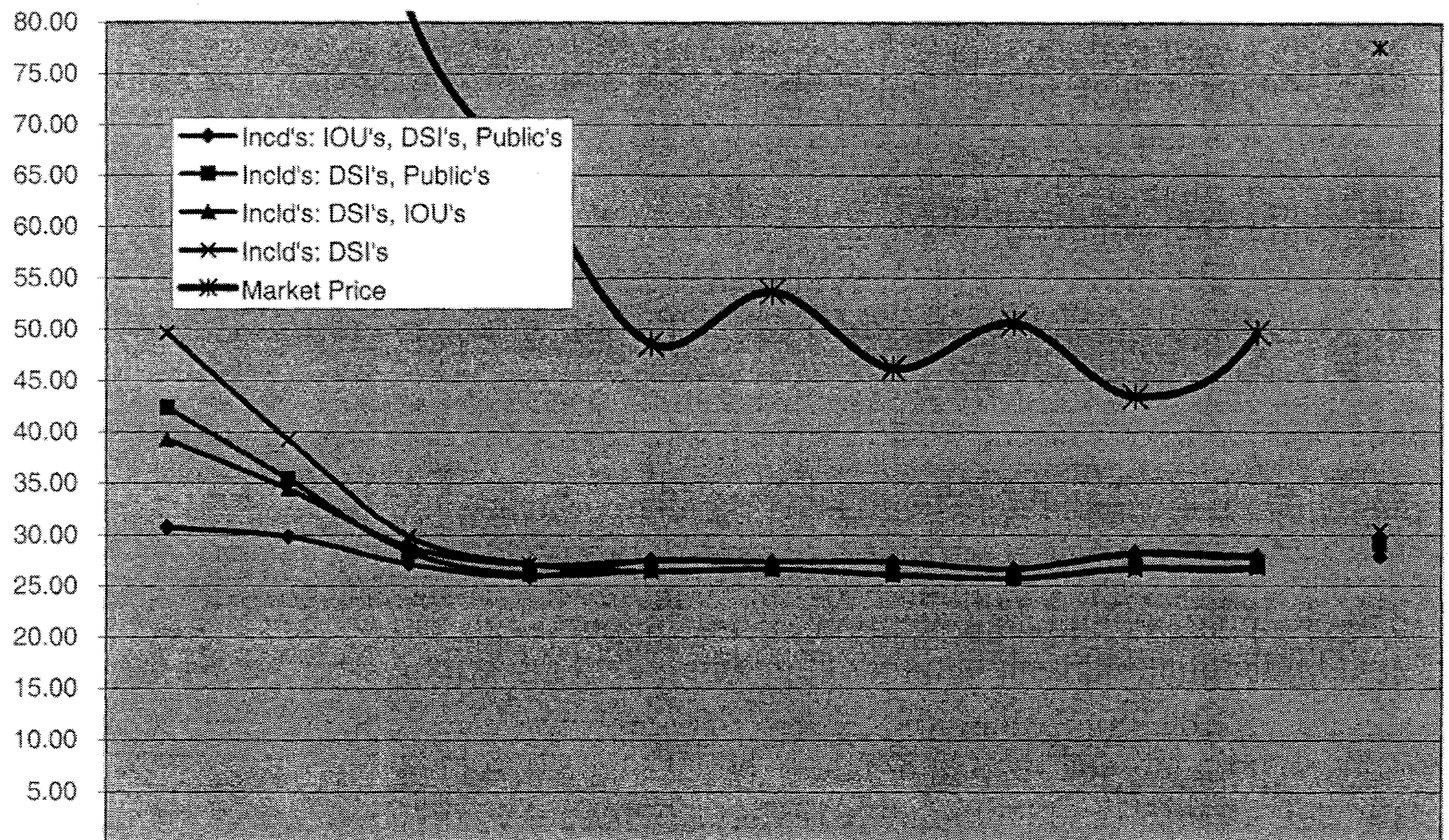
	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	61%	61%	40%	35%	44%	45%	42%	40%	47%	47%	46%
Incld's: DSI's, Public's	145%	109%	58%	41%	43%	45%	40%	40%	43%	46%	61%
Incld's: DSI's, IOU's	121%	98%	56%	44%	44%	45%	42%	40%	47%	47%	58%
Incld's: DSI's	196%	140%	72%	50%	42%	45%	39%	40%	43%	46%	71%

Est. Flat PF Rate and Market Price - Low Market Case



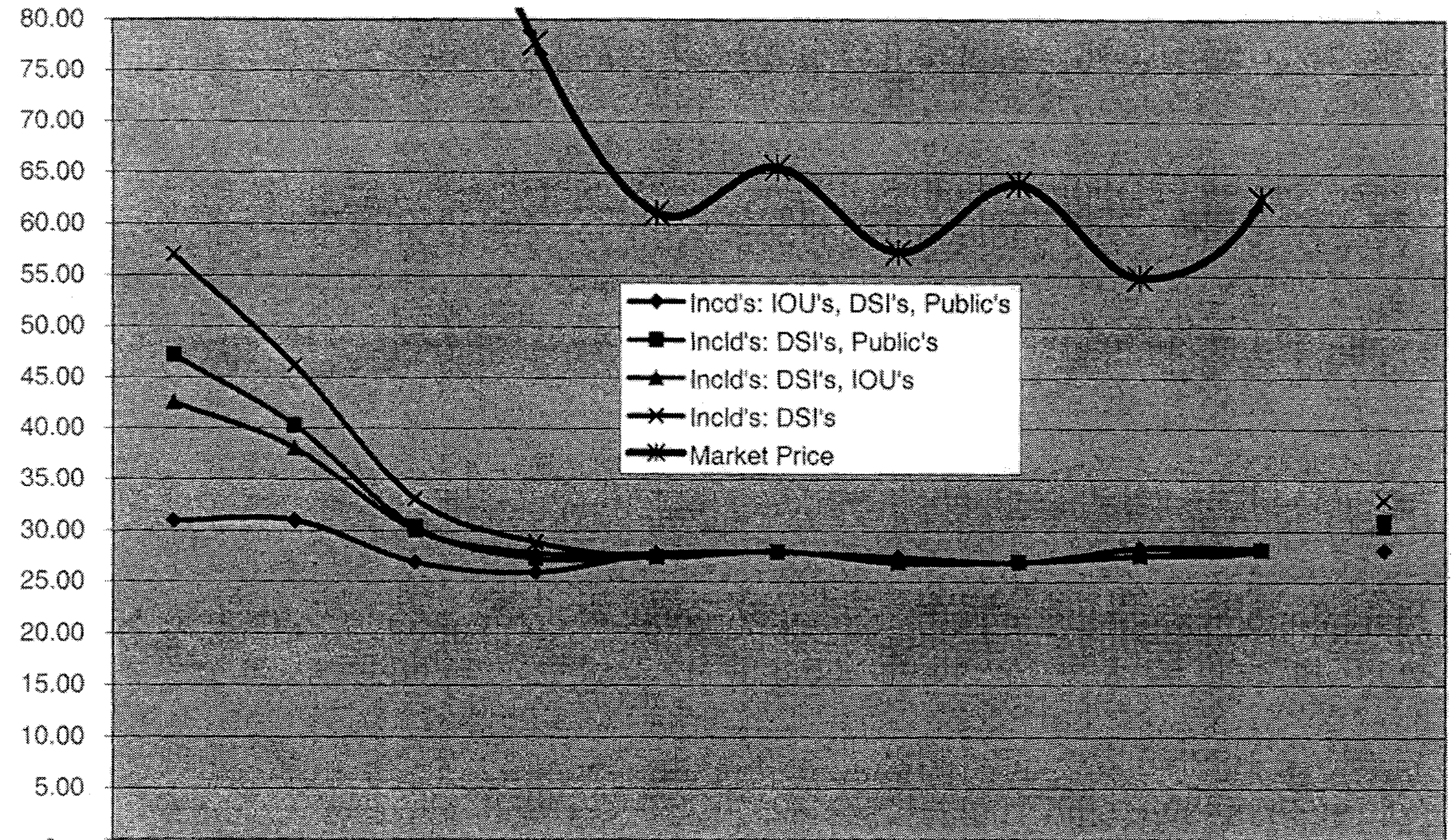
	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	30.48	28.72	27.46	25.91	27.11	26.50	27.38	26.39	28.14	27.48	27.56
Incld's: DSI's, Public's	36.43	30.53	25.95	23.66	24.72	24.16	24.85	23.92	25.49	24.86	26.46
Incld's: DSI's, IOU's	35.21	30.79	27.35	25.43	26.98	26.33	27.15	26.11	27.78	27.06	28.02
Incld's: DSI's	40.48	32.33	25.92	23.33	24.60	24.02	24.65	23.69	25.17	24.50	26.87
Market Price	140.40	82.90	46.29	36.69	27.67	30.58	26.33	28.83	24.77	28.31	47.28

Est. Flat PF Rate and Market Prices - Current Market Case



	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	30.75	29.86	27.16	25.91	27.53	27.42	27.42	26.71	28.28	27.99	27.90
Incld's: DSI's, Public's	42.38	35.40	28.36	26.10	26.46	26.67	26.16	25.80	26.84	26.92	29.11
Incld's: DSI's, IOU's	39.26	34.42	28.84	27.06	27.48	27.38	27.31	26.62	28.10	27.84	29.43
Incld's: DSI's	49.63	39.28	29.86	27.14	26.41	26.64	26.07	25.73	26.68	26.79	30.42
Market Price	212.73	125.60	81.22	64.36	48.54	53.65	46.19	50.59	43.45	49.67	77.60

Est. Flat PF Rate and Market Prices - High Market Case



	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
Incd's: IOU's, DSI's, Public's	30.97	31.00	26.91	25.92	27.77	27.90	27.44	26.90	28.36	28.29	28.15
Incld's: DSI's, Public's	47.18	40.28	30.35	27.24	27.45	27.98	26.88	26.91	27.62	28.13	31.00
Incld's: DSI's, IOU's	42.53	38.05	30.09	27.82	27.76	27.92	27.40	26.93	28.28	28.30	30.51
Incld's: DSI's	57.01	46.23	33.12	28.91	27.45	28.01	26.85	26.93	27.55	28.14	33.02
Market Price	270.21	168.61	109.88	77.74	61.12	65.55	57.34	63.94	54.85	62.55	99.18

Base Case w/ IOU's

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	58%	49%	43%	35%	41%	38%	42%	37%
Med	60%	55%	41%	35%	43%	42%	42%	39%
High	61%	61%	40%	35%	44%	45%	42%	40%

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	30.48	28.72	27.46	25.91	27.11	26.50	27.38	26.39
Med	30.75	29.86	27.16	25.91	27.53	27.42	27.42	26.71
High	30.97	31.00	26.91	25.92	27.77	27.90	27.44	26.90

Base Case wo/ IOU's

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	89%	59%	35%	23%	28%	25%	29%	24%
Med	120%	84%	47%	36%	37%	38%	36%	34%
High	145%	109%	58%	41%	43%	45%	40%	40%

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	36.43	30.53	25.95	23.66	24.72	24.16	24.85	23.92
Med	42.38	35.40	28.36	26.10	26.46	26.67	26.16	25.80
High	47.18	40.28	30.35	27.24	27.45	27.98	26.88	26.91

Base Case wo/ Publics

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	83%	60%	42%	32%	40%	37%	41%	36%
Med	104%	79%	50%	40%	43%	42%	42%	38%
High	121%	98%	56%	44%	44%	45%	42%	40%

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	35.21	30.79	27.35	25.43	26.98	26.33	27.15	26.11
Med	39.26	34.42	28.84	27.06	27.48	27.38	27.31	26.62
High	42.53	38.05	30.09	27.82	27.76	27.92	27.40	26.93

Base Case wo/ Publics wo/Ious

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	110%	68%	35%	21%	28%	25%	28%	23%
Med	158%	104%	55%	41%	37%	38%	35%	34%
High	196%	140%	72%	50%	42%	45%	39%	40%

	1st 02	2nd 02	1st 03	2nd 03	1st 04	2nd 04	1st 05	2nd 05
Low	40.48	32.33	25.92	23.33	24.60	24.02	24.65	23.69
Med	49.63	39.28	29.86	27.14	26.41	26.64	26.07	25.73
High	57.01	46.23	33.12	28.91	27.45	28.01	26.85	26.93

1st 06	2nd 06	Ave
46%	43%	43%
47%	45%	45%
47%	47%	46%

1st 06	2nd 06	Ave
28.14	27.48	27.56
28.28	27.99	27.90
28.36	28.29	28.15

1st 06	2nd 06	Ave
32%	29%	37%
39%	40%	51%
43%	46%	61%

1st 06	2nd 06	Ave
25.49	24.86	26.46
26.84	26.92	29.11
27.62	28.13	31.00

1st 06	2nd 06	Ave
44%	41%	45%
46%	45%	53%
47%	47%	58%

1st 06	2nd 06	Ave
27.78	27.06	28.02
28.10	27.84	29.43
28.28	28.30	30.51

1st 06	2nd 06	Ave
31%	27%	40%
39%	39%	58%
43%	46%	71%

1st 06	2nd 06	Ave
25.17	24.50	26.87
26.68	26.79	30.42
27.55	28.14	33.02

Low

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	58%	49%	43%	35%
Incld's: DS	89%	59%	35%	23%
Incld's: DS	83%	60%	42%	32%
Incld's: DS	110%	68%	35%	21%

Med

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	60%	55%	41%	35%
Incld's: DS	120%	84%	47%	36%
Incld's: DS	104%	79%	50%	40%
Incld's: DS	158%	104%	55%	41%

High

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	61%	61%	40%	35%
Incld's: DS	145%	109%	58%	41%
Incld's: DS	121%	98%	56%	44%
Incld's: DS	196%	140%	72%	50%

Low

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	30.48	28.72	27.46	25.91
Incld's: DS	36.43	30.53	25.95	23.66
Incld's: DS	35.21	30.79	27.35	25.43
Incld's: DS	40.48	32.33	25.92	23.33
Market Pric	140.40	82.90	46.29	36.69

Med

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	30.75	29.86	27.16	25.91
Incld's: DS	42.38	35.40	28.36	26.10
Incld's: DS	39.26	34.42	28.84	27.06
Incld's: DS	49.63	39.28	29.86	27.14
Market Pric	212.73	125.60	81.22	64.36

High

	1st 02	2nd 02	1st 03	2nd 03
Incd's: IOU	30.97	31.00	26.91	25.92
Incld's: DS	47.18	40.28	30.35	27.24
Incld's: DS	42.53	38.05	30.09	27.82
Incld's: DS	57.01	46.23	33.12	28.91
Market Pric	270.21	168.61	109.88	77.74

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
41%	38%	42%	37%	46%	43%	43%
28%	25%	29%	24%	32%	29%	37%
40%	37%	41%	36%	44%	41%	45%
28%	25%	28%	23%	31%	27%	40%

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
43%	42%	42%	39%	47%	45%	45%
37%	38%	36%	34%	39%	40%	51%
43%	42%	42%	38%	46%	45%	53%
37%	38%	35%	34%	39%	39%	58%

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
44%	45%	42%	40%	47%	47%	46%
43%	45%	40%	40%	43%	46%	61%
44%	45%	42%	40%	47%	47%	58%
42%	45%	39%	40%	43%	46%	71%

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
27.11	26.50	27.38	26.39	28.14	27.48	27.56
24.72	24.16	24.85	23.92	25.49	24.86	26.46
26.98	26.33	27.15	26.11	27.78	27.06	28.02
24.60	24.02	24.65	23.69	25.17	24.50	26.87
27.67	30.58	26.33	28.83	24.77	28.31	47.28

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
27.53	27.42	27.42	26.71	28.28	27.99	27.90
26.46	26.67	26.16	25.80	26.84	26.92	29.11
27.48	27.38	27.31	26.62	28.10	27.84	29.43
26.41	26.64	26.07	25.73	26.68	26.79	30.42
48.54	53.65	46.19	50.59	43.45	49.67	77.60

1st 04	2nd 04	1st 05	2nd 05	1st 06	2nd 06	Ave
27.77	27.90	27.44	26.90	28.36	28.29	28.15
27.45	27.98	26.88	26.91	27.62	28.13	31.00
27.76	27.92	27.40	26.93	28.28	28.30	30.51
27.45	28.01	26.85	26.93	27.55	28.14	33.02
61.12	65.55	57.34	63.94	54.85	62.55	99.18