# WHOLESALE POWER RATE

# DEVELOPMENT STUDY

PREPARED BY

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

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COMMONLY USED ACRONYMS

| | |
|---|---|
| AC | Alternating Current |
| ACME | Accelerated California Market Estimator (computer program) |
| AFUDC | Allowance for Funds Used During Construction |
| aMW | Average Megawatt |
| APS | Ancillary Products and Services (rate) |
| ASC | Average System Cost |
| ASM | Aluminum Smelter Model |
| BASC | BPA Average System Cost |
| BTU | British Thermal Unit |
| CE | Emergency Capacity (rate) |
| CF | Firm Capacity (rate) |
| CO-OP | Co-operative Electric Utility |
| COB | California-Oregon Border |
| COE | United States Army Corps of Engineers |
| Con/Mod | Conservation Modernization Program |
| COSA | Cost of Service Analysis |
| CSPE | Columbia Storage Power Exchange |
| CT | Combustion Turbine |
| CWIP | Construction Work In Progress |
| CY | Calendar Year (Jan - Dec) |
| DC | Direct Current |
| DOE | Department of Energy |
| DSIs | Direct Service Industrial Customers |
| DSM | Demand-Side Management |
| EA | Environmental Assessment |
| ECC | Energy Content Curve |
| EIS | Environmental Impact Statement |
| ET | Energy Transmission (rate) |
| F & O | Financial and Operating Reports |
| FBS | Federal Base System |
| FCRPS | Federal Columbia River Power System |
| FCRTS | Federal Columbia River Transmission System |
| FELCC | Firm Energy Load Carrying Capability |
| FERC | Federal Energy Regulatory Commission |

| | |
|---|---|
| IE | Eastern Intertie Transmission (rate) |
| IN | Northern Intertie Transmission (rate) |
| IOUs | Investor-Owned Utilities |
| IP | Industrial Firm Power (rate) |
| IR | Integration of Resources (rate) |
| IRE | Industrial Replacement Energy |
| IS | Southern Intertie Transmission (rate) |
| ISAAC | Integrated System for Analysis of Acquisitions (computer program) |
| ISC | Investment Service Coverage |
| KV | Kilovolt (1000 volts) |
| KW | Kilowatt (1000 watts) |
| kWh | Kilowatthour |
| LDD | Low Density Discount |
| LOLP | Loss of Load Probability |
| LTIAP | Long-Term Intertie Access Policy |
| M/kWh | Mills per kilowatthour |
| MC | Marginal Cost |
| MCA | Marginal Cost Analysis |
| MCS | Model Conservation Standards |
| MW | Megawatt (1 million watts) |
| MW-miles | Megawatt-miles |
| MWh | Megawatthour |
| MT | Market Transmission (rate) |
| NEPA | National Environmental Policy Act |
| NF | Nonfirm Energy (rate) |
| NFRAP | Nonfirm Revenue Analysis Program (computer program) |
| NOB | Nevada-Oregon Border |
| NR | New Resource Firm Power (rate) |
| NTSA | Non-Treaty Storage Agreement |
| NWPP | Northwest Power Pool |
| NWPPC | Northwest Power Planning Council |
| O&M | Operation and Maintenance |
| OMB | Office of Management and Budget |
| OY | Operating Year (Jul - Jun) |
| PA | Public Agency |
| PIP | Programs in Perspective |
| PF | Priority Firm Power (rate) |

| | |
|---|---|
| RAM | Rate Analysis Model (computer model) |
| REVEST | Revenue Estimate (computer program) |
| ROD | Record of Decision |
| RP | Reserve Power (rate) |
| RPSA | Residential Purchase and Sale Agreement |
| SAM | System Analysis Model |
| SI | Special Industrial Power (rate) |
| SPM | Supply Pricing Model (computer program) |
| SPOM | Surplus Power-Open Market |
| SS | Share-the-Savings Energy (rate) |
| TGT | Townsend-Garrison Transmission (rate) |
| UFT | Use of Facilities Transmission (rate) |
| USBR | United States Bureau of Reclamation |
| VI | Variable Industrial Power (rate) |
| VOR | Value of Reserves |
| WNP | Washington Public Power Supply System (Nuclear) Project |
| WPPSS | Washington Public Power Supply System |
| WPRDS | Wholesale Power Rate Development Study |
| WSPP | Western Systems Power Pool |
| WSCC | Western Systems Coordinating Council |

# 1. INTRODUCTION

## 1.1 Purpose

The Wholesale Power Rate Development Study (WPRDS) designs rates for BPA’s wholesale power products and services. The WPRDS contains a cost of service analysis (COSA), which allocates BPA’s test-period revenue requirement to customer classes based on cost causation. The allocated COSA costs are adjusted and then used in the rate design processes for wholesale power products and services. The end result of the WPRDS is the 5-year wholesale power rates that appear in BPA’s proposed rate schedules, which are published in the 1996 Administrator’s Record of Decision, WP-96-A-02, Appendix.

BPA’s rates are developed to recover BPA’s costs in total, and the COSA allocates those costs (BPA’s test period revenue requirements) to each of BPA's customer classes. The COSA results are subsequently modified through rate design adjustments: (1) to reflect BPA's rate design objectives; (2) to comport with contractual requirements; (3) to reflect the results of other BPA rate case studies; (4) to reflect the emerging competition in the electric industry; and (5) to conform with requirements of applicable legislation, including the Bonneville Project Act, the Flood Control Act of 1944, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). BPA's rate design objectives include recovery of BPA's projected revenue requirements, practicality, fairness, and efficiency.

(4) BPA’s projections of revenues from sales of unbundled products and services; (5) statutory requirements; (6) generally accepted ratemaking practices; (7) economic theory; and (8) BPA's policy and marketing objectives. The test period used for setting the 1996 proposed rates is the 5-year period covering fiscal years (FY) 1997 through 2001, beginning October 1, 1996, and ending September 30, 2001. It was assumed for ratemaking purposes that most of BPA’s customers will continue to purchase under their 1981 Contracts, as amended, throughout the rate test period. Some of BPA’s direct-service industrial customers have signed new 1996 Contracts.

The parties to the 1996 rate proceeding conducted settlement discussions and produced two settlement agreements: the “Transmission Rates and Terms and Conditions Settlement Agreement,” WP-96-E-BPA-129, and the “Power and Transmission Partial Settlement Agreement,” WP-96-E-BPA-128. The former, the Transmission Settlement, was intended by the parties to settle all issues relating to transmission rates, terms and conditions for the 5-year settlement period, from October 1, 1996, through September 30, 2001. The latter, the Power Settlement, provides that the parties agreeing to it also agree to the Transmission Settlement. The Power Settlement also provides that the Priority Firm Power rate should be established at “equal to or less than 24.4 mills per kWh as shown on line 21 of Table RDS 50 of the 1996 Final Documentation to the Wholesale Power Rate Development Study.” The Power Settlement also contains a specific proposal for assumptions relating to any underrecovery of Utility Delivery facilities’ cost due to the limit on the Delivery Charge, a proposal for the establishing the level of the Availability Charge, a proposal for the definition of Computed Maximum Requirement, and a proposal for the availability of Partial Load Shaping. The “utility delivery underrecovery” cost is the relevant sections of the 1996 Administrator's Record of Decision, WP-96-A-02; the settlements are discussed in general in ROD section 1.1.3.

## 1.2 Overview and Models

The WPRDS calculates BPA's proposed rates based on information either developed in the WPRDS or supplied by the other studies that make up BPA's rate proposal. All of these studies have accompanying documentation that provides the detail of computations and assumptions. In general, revenue requirements information is provided by the Revenue Requirement Study (WP-96-FS-BPA-02) and its accompanying documentation (WP-96-FS-BPA-02A and -02B). Information about loads and resources is provided by the Loads and Resources Study (WP-96-FS-BPA-01) and its documentation (WP-96-FS-BPA-01A and -01B). The Section 7(b)(2) Rate Test Study, WP-96-FS-BPA-07, and its documentation implement section 7(b)(2) of the Northwest Power Act to ensure that BPA's preference customers' firm power rates applied to their general requirements are no higher than rates calculated using specific assumptions. The Marginal Cost Analysis Study, WP-96-FS-BPA-04, provides the WPRDS with information regarding seasonal and diurnal differentiation of energy charges, as well as prices for demand and unbundled power products. The Transmission Rate Design Study (TRDS) determines the transmission costs that are assigned to the BPA power business and thus recovered through power rate charges. The TRDS also designs and calculates the transmission component of the power rates.

RAM consists of a series of tables, each of which shows a sequential step in BPA's rate development process. Section 3 of the Documentation for the WPRDS includes the RAM tables and supporting documentation. Also included in the Documentation for the WPRDS are those rate calculations not performed in the RAM, such as rates for unbundled products, including Load Shaping, and other charges such as the Availability Charge and the Power Demand Reservation Charge.

One of the computer programs used by RAM is the Nonfirm Revenue Analysis Program (NFRAP). The NFRAP is used to forecast sales of available secondary and surplus firm energy in the Pacific Northwest and Pacific Southwest. The forecasts produced by the NFRAP are used in the COSA, rate design, and revenue forecasts. Two other computer models, the Accelerated California Market Estimator (ACME) and the Federal Secondary Energy Analysis (FSEA), provide information that is input to the NFRAP. A discussion of these computer applications for secondary energy modeling is included in section 2 of the Documentation for the WPRDS. Documentation of NFRAP, as part of RAM, is included in section 3 of the WPRDS Documentation.

1.3 <u>Organization</u>

The WPRDS is divided into seven sections. The first is this Introduction. Following are: 2. Cost Allocation and Rate Design Implementation; 3. Unbundled Power Products; 4. Rate Design Changes; 5. Revenue Forecast; 6. Risk Analysis; and 7. Rate Schedule Descriptions. Details of competitive utility marketplace, and an intent to reposition BPA's products in the market in order to make BPA more competitive. BPA also is revising its rate design to reflect cost causation more accurately and provide price signals that will result in more efficient use of the generation and transmission systems. There are four primary means BPA is using to reposition its products in the market. The first is unbundled power products; the second is offering power, transmission, and unbundled products at rates with terms longer than 2 years; the third is adding more seasonal and diurnal time differentiation to BPA's energy charges; and the fourth is charging power users separately for transmission instead of rolling these costs into the power rates demand charges. BPA is proposing modifications to its cost allocations to implement these rate design changes.

Unbundled products are discussed in WPRDS section 3. Five-year power rates are discussed in section 4.1, and reflected in the wholesale power rate schedules, WP-96-A-02, Appendix. Time differentiation and marginal costs, including prices for demand and unbundled power products, are discussed in the Marginal Cost Analysis Study (WP-96-FS-BPA-04) and Documentation (WP-96-FS-BPA-04A). Changes to the energy and demand billing factors are addressed in WPRDS sections 4.2 and 4.3. BPA also is proposing a number of other rate design changes that arise from these major changes or are required to implement them.

The intent behind the changes in rate design is to develop proposed rates that allow potential purchasers to choose among a number of products and services and purchase periods that best meet their system needs. To promote the efficient use of BPA's system, BPA's products and services must be priced so as to send accurate price signals to potential purchasers for comparison

# 2. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

## 2.1 Ratemaking Sequence Overview

The Wholesale Power Rate Development Study (WPRDS) includes a Cost of Service Analysis (COSA) and a series of rate design adjustments.  The COSA assigns responsibility for BPA's revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with legislation governing BPA's ratemaking. Subsequent rate design adjustments to the allocated costs in the COSA are necessary for a variety of reasons, primarily to assure that BPA recovers its test period costs, and to implement various policy objectives.

## 2.2 Cost of Service Analysis

The COSA allocates the test period generation revenue requirements that are determined in the Revenue Requirement Study, WP-96-FS-BPA-02, to BPA's customer classes.  The COSA apportions or "allocates" the test period generation revenue requirements among classes of service based on the principle of cost causation.  The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to the classes' use.  Cost allocation also is based on the priorities of service from resource pools to rate pools indicated in section 7 of the Northwest Power Act.

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Two of the steps, functionalization of costs between generation and transmission and segmentation of BPA's transmission system costs, are performed in conjunction with the development of BPA's revenue requirements. BPA's costs are functionalized in BPA's Revenue Requirement Study (WP-96-FS-BPA-02). The Segmentation Study (WP-96-FS-BPA-03) provides the basis for segmenting the transmission revenue requirements used to develop rates. The functionalized and segmented test period revenue requirements then are used in the Transmission Rate Design Study (TRDS) (WP-96-FS-BPA-06) to set transmission rates, including the transmission component of the power rates. The remaining steps to determine BPA's cost of service for wholesale power--classification and allocation of costs--are performed in the COSA portion of the WPRDS.

2.2.1 Revenue Requirement. The Bonneville Project Act, the Flood Control Act of 1944, the Federal Columbia River Transmission System Act, and the Northwest Power Act require BPA to design rates that will result in sufficient revenues and assure the recovery of all costs of acquiring, conserving, and transmitting the electric power that BPA markets. These costs include repayment of the Federal investment in the Federal Columbia River Power System (FCRPS) over a reasonable number of years and all other costs incurred by the Administrator. The Revenue Requirement Study, WP-96-FS-BPA-02, determines whether BPA's current rates will produce enough revenue to satisfy BPA's revenue requirements (current revenue test).

The 1996 Revenue Requirement Study is based on revenue and cost estimates for a 5-year test five test years, the total adjusted generation revenue requirement is $13.166 billion. Adjusted annual functionalized revenue requirements used for rate calculations are shown in Tables COSA06FY 97 through COSA06FY 01. Total adjusted functionalized revenue requirements for the 5-year period are shown in Table COSA08.

2.2.1.1 Functionalized Revenue Requirement. In compliance with a Federal Energy Regulatory Commission order dated January 27, 1984 (26 F.E.R.C. ¶ 61,096), BPA determines separate revenue requirements for the generation and transmission components of the FCRPS. Accordingly, BPA prepares separate power repayment studies for the generation and transmission functions. All costs to be recovered through FCRPS rates are functionalized between generation and transmission to develop the revenue requirements used in this rate proposal.

The Revenue Requirement Study also includes separate demonstrations for generation and transmission to show that proposed revenues are adequate to recover all costs of the FCRPS in the rate period and over the repayment period (revised revenue test).

2.2.1.2 Segmented Transmission Revenue Requirement. BPA operates and maintains the FCRTS to provide various transmission services throughout the region. Because most services do not require use of the entire system, the FCRTS is divided into segments, each providing a distinct type of service. The Segmentation Study (WP-96-FS-BPA-03) categorizes the facilities of the FCRTS by segment to identify the costs of transmission services, thereby providing a basis for equitable allocation of transmission costs between Federal and non-Federal users of the affected by the proposed Priority Firm Power (PF) rate. In the beginning of the rate development process, residential exchange program costs are projected using an estimate of the PF rate for the test period. These costs are included in the functionalized revenue requirements. If the proposed PF rate differs from the estimated rate, the residential exchange program cost is recalculated. Then the PF rate is recalculated based on the revised residential exchange program costs. This iterative process stops when the PF rate does not change from the previous iteration. This adjustment of the gross residential exchange program costs is necessary because the PF rate level influences the level of the residential exchange costs included in the COSA.

2.2.1.4 Adjustments of Short-Term Purchased Power Costs. Two categories of purchased power are shown in the COSA: (1) purchased power; and (2) short-term operational purchases (balancing purchased power), which can be firm or nonfirm. Purchased power is acquired under contracts from the early 1990s. Included in the costs of short-term operational purchases are the costs of power purchases and storage required to meet firm deficits (balancing purchases). Projected short-term operational purchases are needed to serve firm loads at the margin in months other than the spring fish migration period. The expense estimate for short-term operational purchases included in the revenue requirements is adjusted in the COSA as a result of NFRAP modeling, to reflect projected operation of the FCRPS. Costs of short-term operational purchases are included in and allocated as Federal Base System costs. Costs of purchased power from contracts from the early 1990s are included in the New Resources resource pool.

2.2.2 Classification. Classification in the WPRDS apportions generation costs between the

The classification methodology BPA uses is based on the marginal costs of the components of power and generally accepted ratemaking procedures. BPA sets the price for demand at the marginal cost of demand plus the costs of transmission revenue deficiencies. These transmission revenue deficiencies are generation transmission costs that are not allocated to any particular customer group. BPA sets the prices of unbundled products and services at their marginal costs, as determined in the Marginal Cost Analysis Study, WP-96-FS-BPA-04. Sales and revenues of these products are then forecasted. Forecasted revenues associated with demand are classified to capacity. Forecasted revenues associated with unbundled products and services are classified to rights to energy. Generation costs classified to energy are the residual of total generation costs not classified to capacity or rights to energy. By virtue of this classification scheme, costs of capacity or rights to energy are not directly allocated; rather, the costs are equal to the revenues forecasted. The only allocation of costs in the COSA is for costs associated with energy.

2.2.3 Allocation. Allocation is the apportionment of costs to customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools, pursuant to the rate directives contained in section 7 of the Northwest Power Act. Rate pools are groupings of customer classes (loads) for cost allocation purposes. BPA groups its loads into the Priority Firm, Industrial Firm, and All Other categories corresponding to sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the Federal Base System, Residential Exchange, and New Resources resource pools. Costs associated with each of these resources are grouped together to facilitate allocation. The sizes of the rate and resource pools are determined from planning load and resource balances prepared in residential exchange program established in section 5(c) of the Act. The 7(c) rate pool includes loads of BPA's direct-service industrial (DSI) customers. The 7(f) rate pool includes all other power BPA sells in the Pacific Northwest. Subsequent to 1985 and implementation of the directives of section 7(c)(2) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

For the 1996 rate proposal, the FBS resource pool consists of: (1) the Federal Columbia River Power System hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reduction in the capability of the above resources. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool for the 1996 rate proposal. For details, *see* Table SDC01 in the WPRDS Documentation, WP-96-FS-BPA-05A.

In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures. The costs of such balancing purchases are considered to be FBS costs and are allocated as such.

2.2.3.1 Delivered Energy Cost Allocations. The process for allocating energy costs begins with an examination of critical period firm loads and resources to determine the amount of monthly firm energy surplus or deficit. Then, a ratemaking load and resource balance for each month of resource pool's costs to BPA's classes of service, are calculated based on identified service from resource pools to rate pools in the ratemaking load and resource balances.

Critical Period Loads and Resources. The Loads and Resources Study, WP-96-FS-BPA-01, contains information on projected loads and resources assuming the same water conditions as occurred in 1930, a year of relatively low streamflows in the 50-year historical water record. BPA's hydro studies used in the resource planning process simulate energy production by the hydro system also assuming streamflows that occurred during the 1930 water year. This assumption is consistent with the past practice of using the critical streamflows that occurred during a 42-month historical period, a practice known as "critical period planning." Loads and resources developed using 1930 water year assumptions are used in the COSA as the basis for constructing the ratemaking load and resource balances, and in the development of allocation factors for the costs of firm power.

Determination of Test Period Firm Surplus or Deficit. This step quantifies the amount of monthly firm energy surpluses or deficits for the rate test period and develops an energy load and resource balance. For this purpose, the COSA uses monthly loads and resources from the Loads and Resources Study. Monthly total energy loads are compared to total energy resources including regulated Federal hydro resources. The difference between the two totals is either the amount of the balancing purchased power necessary to meet firm loads in non-fish migration months, or the amount of surplus firm power available for sale. During the months when fish migration is expected to take place, BPA assumes that no surplus firm power can be sold at fully months is 631 average megawatts (aMW) for the 5-year test period, FYs 1997 through 2001. To construct the ratemaking monthly energy load and resource balances, the balancing purchased power is included as a separate component of the FBS. *See* Table EAF02.

Energy Allocation Factors. When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown on Table EAF05. The Total Usage and Conservation allocation factors are the same, and are based on the sum of the FBS, Exchange, and New Resources allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated energy costs are shown on Tables COSA11 and RDS01.

2.2.3.2 Rights to Energy Cost Recovery. BPA classifies generation costs between delivered energy and rights to energy. The amount of costs classified to rights to energy is based upon the expected revenues to be derived from the sale of unbundled power products. The forecasted revenues include Load Shaping and Load Regulation, and small amounts for other products sold under the FPS and APS rate schedules. The revenues for Load Regulation, Load Shaping, and Control Area Reserves are based on sales estimates for these products and the costs of providing these products.

2.2.3.4 Other Cost Allocations. Costs not directly identifiable with rate pools, resource pools, or transmission are allocated as described below.

Fish and Wildlife Program Costs. Fish and wildlife program costs, which are functionalized to generation, are incurred primarily because of the hydro system resources in the FBS and their operations. As such, these costs are included in the total costs of the FBS resources. Resource cost allocations are described in section 2.2.3.

Conservation Costs. Conservation costs include costs of Existing Activities, Market Transformation, and Energy Services Business. As described in the Draft Strategic Business Plan, BPA plans to have an Energy Services Business that is self-supporting by the year 2001. During the transition period, energy services costs not recovered from the Energy Services Business (net costs of the Energy Services Business) will be recovered from other business lines. For this rate period, BPA proposes to allocate the net cost of the Energy Service Business uniformly over all kilowatthours sold. These costs (credits) are allocated in the same manner as conservation costs. Revenues from the Energy Services Business are included in the Revenue Forecast. Remaining conservation costs are allocated uniformly over all kilowatthours sold. *See* Table COSA11.

BPA Program Costs. Some BPA program costs are not directly identified with any specific resource pool, transmission service, or customer class. An example is the cost of the ratemaking process. The generation and transmission portions of these costs are determined in

WNP-3 Settlement Exchange Agreement Costs. The revenue requirement includes costs related to the WNP-3 Settlement Exchange Agreement between BPA and four IOUs that have a 30 percent interest in the WNP-3 nuclear plant. Two types of WNP-3 Settlement Exchange costs are allocated in the COSA: plant-related costs and exchange energy costs. Under the WNP-3 Settlement Agreement, BPA is obligated to serve a specified amount of IOU load. Whether BPA must purchase to serve WNP-3 obligations is determined in the NFRAP. To serve the IOU load, BPA may purchase either Company Exchange Energy from the IOUs or other, lower-cost power. The exchange energy costs are the projected costs of purchases of Company Exchange Energy (which may not exceed the costs of combustion turbines) or other purchases and storage in lieu of Company Exchange Energy.

These costs are allocated uniformly to all loads using the total usage allocation factors for energy (*see* Table RDS03).

Balancing Power Purchases. Short-term purchases of power and off-system storage services are made to meet monthly firm load deficits, provide operational flexibility, displace higher-cost purchases, and provide for certain fish mitigation measures. The amount and use of purchased power reflect the projected operation of the FCRPS.

These costs are allocated as FBS costs. *See* the resource allocation discussion in section 2.2.1.4.

peaking energy delivered; and (4) receipt by BPA of exchange energy as payment for the capacity delivered by BPA.

Peaking energy delivered with peaking capacity is assumed to be provided entirely by the Federal hydro system. Peaking energy loads are therefore excluded, for cost allocation purposes, from any rate pool. Excluding the peaking energy supplied for these exchanges from loads causes the amount of regulated hydro resource to be reduced, because fewer resources are required to balance loads and resources. In this manner, all peaking energy is supplied by the FBS, and the exclusion of peaking energy from loads avoids any generation costs being allocated to the peaking energy supplied. Replacement energy, which is equivalent to the peaking energy loads, is returned entirely to the FBS, so replacement energy increases the projected capability of the FBS.

Only transmission costs are allocated to post-Act exchanges. Because these are non-cash transactions, no revenues will be recovered, and the allocated transmission costs will become a revenue deficiency (*see* section 2.3.3).

<u>Planned Net Revenues for Risk</u>. Planned net revenues for risk is the amount of net revenues required to ensure that cash flow from proposed rates fully meets BPA's probability standard for repaying Treasury on time and in full. The planned net revenues for risk are functionalized entirely to generation and are allocated to resource pools that include Federal capital investments. The methodology is described and illustrated in the Revenue Requirement Study, WP-96-FS-BPA-02, Chapter 4.

In this 1996 rate proposal, revenues from Columbia Storage Power Exchange are treated as a revenue credit. CSPE contracts are a product of the Treaty between the United States and Canada relating to the cooperative development of the water resources of the Columbia River Basin. BPA incurred obligations to generate and transmit capacity and energy. The CSPE contracts require BPA to sell Supplemental and Entitlement capacity at a fixed price of $5.50 per kilowatt-year and to transmit Supplemental capacity and CSPE power at a fixed price of $1.50 per kilowatt-year.

Revenue credits are shown on Table COSA09.

2.2.4 Development of Power Rates Demand Charge. The power rates demand charge is the marginal cost of demand as developed in the Marginal Cost Analysis Study, WP-96-FS-BPA-04, plus the costs of transmission revenue deficiencies (*see* Table RDS11). These revenue deficiencies are generation transmission costs that are not allocated to any particular customer group. Costs associated with demand for each class of service are calculated in Table RDS07. These costs are totaled, and subtracted, along with costs of unbundled products, from BPA's total generation revenue requirement.

2.2.5 COSA Results. The result of the COSA process is the allocation of the test period revenue requirements for energy to classes of service served with firm power. Tables COSA11 and RDS01 summarize the allocated generation energy revenue requirements, and the total allocated

### 2.3 Rate Design Adjustments

Rate design adjustments are performed sequentially in the order described below.

2.3.1 WNP-3 Settlement Exchange Credit. As part of the WNP-3 Settlement Exchange Agreement, the IOUs have agreed to pay BPA a price per kilowatthour equivalent to the average operation and maintenance (O&M) costs of four surrogate nuclear plants in return for BPA providing them power that would have been produced if the WNP-3 plant were operating. The WNP-3 Settlement Exchange Credit Adjustment identifies BPA's projected revenues from the IOUs for service to the WNP-3 Settlement Exchange loads. These are excess revenues, because the WNP-3 Settlement Exchange loads are served with nonfirm energy to which BPA allocates no cost. BPA allocates a credit for these excess revenues to all its other firm power customers. The total amount of the excess revenue credit for the 5-year test period is $265.860 million. This adjustment is made in Table RDS04.

2.3.2 Excess Revenue Adjustment. The Excess Revenue Adjustment recognizes that revenues will be collected from certain classes of service to which costs are not allocated, and credits these revenues to other customer classes. The source of excess revenues is projected nonfirm energy sales. BPA expects to sell nonfirm energy that will produce $968.0 million in revenues over the 5-year test period. After reducing these revenues by transmission charges totaling $281.8 million, BPA credits its firm power customers with excess revenues totaling $686.1 million over the 5-year test period. This adjustment is made in Table RDS12.

water conditions occur, and therefore, nonfirm energy sales and revenues are projected. These sales and revenues are projected by averaging the results of 50 water years. (*See* Documentation for the WPRDS, WP-96-FS-BPA-05A, section 2.) The projected nonfirm energy revenues are credited to firm loads so that BPA does not recover more than its revenue requirements.

The NFRAP is used to project the level of nonfirm energy sales and revenues. Table RDS11 shows the projected nonfirm energy revenues for the test period.

2.3.2.2 Allocation of Excess Revenues. NF rate revenues are used first to pay transmission costs associated with sales of nonfirm energy, then the remainder is credited to firm power customers. The NF Standard rate is based on the average cost of nonfirm energy. Table RDS05 shows the calculation of the average cost of nonfirm energy.

Excess revenues functionalized to generation are classified to delivered energy, and allocated to loads served with Federal system resources (FBS and New Resources). The generation-related excess revenues are allocated in this manner because they are associated with nonfirm energy service, and the cost of nonfirm energy is based on Federal resource costs only.

2.3.3 Transmission Revenue Deficiencies. Firm power customers benefit from certain uses of the Federal Transmission system, and must be charged for such use. In the past, individual adjustments were made for some of these uses, such as transmission costs that were allocated but unrecoverable through the Montana Capacity/Energy Exchange and the Post-Act

Generation-Integration segment of the transmission system, General Transfer Agreement cost, the Utility Delivery charge underrecovery, and purchased power use of the Interties.

An itemized list of transmission costs billed to generation by year can be found in Table RDS11. The total amount of these transmission revenue deficiencies over the 5-year test period is $358.8 million. BPA allocates these transmission costs to capacity and includes them in the calculation of the demand charge.

2.3.4 Federal Transmission Reallocation Adjustment. In the past, a portion of the gross costs of the residential exchange was functionalized to transmission. These functionalized costs were treated as part of a separate transmission segment, although exchange transmission costs were not considered to be costs of an FCRTS segment. Now, BPA's separate transmission business accounts for only FCRTS costs and use.

Residential exchange costs are not functionalized between generation and transmission, but instead are allocated as generation costs. However, the allocated gross exchange costs actually contain some component that is related to transmission. To avoid multiple allocation of transmission costs, both Federal and exchange, to the individual customer classes, the Federal Transmission Reallocation Adjustment is made in Table RDS16.

First, BPA recognizes the amount of Federal transmission cost recovery from the firm power classes of service indicated in the TRDS. Then the total revenue recovery is calculated for

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the TRDS and the unallocated costs corresponding to service from Federal resources is the amount of the adjustment. This adjustment moves an equivalent amount of energy dollars between classes of service to achieve the desired cost recovery result.

2.3.5 Federal Unbundled Reallocation Adjustment. In theory, when power is exchanged between BPA and participants in the residential exchange, the cost of unbundled products is included in the Average System Cost of the exchanging utilities. Classes of service that are allocated both residential exchange costs and costs of Federal resources therefore may receive a multiple allocation of costs related to unbundled products and services. To avoid such an unintended multiple allocation of costs of unbundled products and services, and to make the allocation of costs of Federal and exchange resources conform to the service indicated in the load and resource balances, an adjustment is made to reallocate Federal unbundled products and services costs. This adjustment is analogous to the Federal Transmission Reallocation Adjustment above.

In this adjustment, total cost recovery for unbundled products and services from Federal resources is reallocated among the firm power classes of service based on the sum of FBS and NR allocation factors. The difference between the cost recovery from Federal resources and the amount of reallocated costs is determined for each firm power class of service. The energy cost allocated to each of these classes is adjusted by this amount.

2.3.6 Firm Power Revenue Deficiency Adjustment. BPA sells firm power at contractual rates and in the open market under the FPS-96 rate schedule. Sales of such firm power are not

Pacific Northwest and Southwest markets. Based on these sales estimates, transmission costs are estimated to be $246.1 million. In addition, BPA has allocated $1.5837 billion in generation costs to the firm power sold. Therefore, there will be a revenue deficiency of $71.0 million over the 5-year test period. This revenue deficiency of allocated costs in excess of revenues is charged to all other firm power (PF, IP, NR) customers. *See* Tables RDS17 and RDS18.

2.3.7 <u>7(c)(2) Adjustment</u>. The DSI rates are based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is made through a value of reserves (VOR) credit. Thus, the DSI rates are set equal to the applicable wholesale rate, plus a typical margin, minus a VOR credit.

The applicable wholesale rates are the PF rates (in combination with the NR rate if new large single loads were projected for the test period) at the DSI load factor. The typical margin is based on the overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The VOR credit is based on an analysis that quantifies the benefit cannot be used to set rates in this rate proceeding. Therefore, BPA has calculated new values for the typical margin and the value of reserves. The methods and calculations used to determine the typical margin and the VOR credit are discussed in greater detail in Appendices A and B, respectively.

A net margin, in mills per kilowatthour, is calculated by subtracting the VOR credit (3.10 mills per kilowatthour) from the typical margin (0.44 mills per kilowatthour). This net margin (-2.66 mills per kilowatthour) is added to the seasonal and diurnal PF energy charges. These adjusted PF energy charges and the charges for demand, transmission, and unbundled products available under the IP rate schedule are applied to the DSI test period billing determinants to determine the initial IP rate. *See* Table RDS20.

The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process is accomplished through an algebraic solution that is shown in Table RDS21.

The size of the 7(c)(2) delta for the 5-year test period is $1.187 billion. This amount is allocated to PF and NR loads. The allocation is based on the energy allocation factors developed in the applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Act.

The Section 7(b)(2) Rate Test Study (WP-96-FS-BPA-07) indicates that the Priority Firm rate applicable to BPA's preference customers must be adjusted.  The amount of protection needed to remove the effects on these customers of the Northwest Power Act as specified in section 7(b)(2) is a reduction of their rate by 3.2 mills per kilowatthour.  BPA therefore makes three adjustments in the rate design sequence to provide this protection to its Priority Firm Preference customers.

In order to make these adjustments, the Priority Firm Rate is bifurcated.  The two resulting rates are the Priority Firm Preference rate and the Priority Firm Exchange rate.  The Priority Firm Preference customer class is given a credit, which will reduce its rate by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study.  The 3.2-mill per kilowatthour protection amount results in a credit of $621.4 million to these customers.

The cost of providing this protection is allocated to the remaining firm power customers in the rate design process (PF Exchange, IP, and NR).  The allocation of this amount between the PF Exchange, IP, and NR classes takes into account the fact that the adjustment itself will cause some exchanging utilities to have Average System Costs (ASCs) below the PF Exchange rate. This allocation methodology is shown in Table X in section 3.5 of the WPRDS Documentation.

The second adjustment is the 7(b)(2) Industrial Adjustment.  The amount of this adjustment is the

A third adjustment is necessary to allocate an increase in the gross exchange costs resulting from the bifurcation of the PF rate causing the PF Exchange rate to be higher than the average combined rate before the bifurcation. This results in higher residential exchange costs. The costs of the residential exchange must be recalculated. Any increase in such costs can only be allocated to the PF Exchange rate itself, and the NR rate. The amount of the adjustment is $187.7 million; it is determined through a set of iterations of the residential exchange cost model. The allocation of this amount is performed in WPRDS Table RDS34.

After the three 7(b)(2) adjustments are made, in the absence of a need for a DSI floor rate adjustment, BPA is able to calculate energy rates for the firm power classes of service. If the DSI rate falls below the floor rate, however, one final adjustment is necessary.

2.3.9 <u>DSI Floor Rate Test</u>. Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the IP rate has been set at a level below the floor rate. If so, an adjustment is made that raises the DSI rate to recover revenues at the floor rate and credits other customers with the increased revenue from the DSIs. If the DSI rate has been set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 1997-2001) DSI billing determinants. Although the energy billing determinants used for this

Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills per kilowatthour basis.

These calculations result in a DSI floor rate of 25.16 mills per kilowatthour. The floor rate is then adjusted by the VOR credit of 3.10 mills per kilowatthour, and the adjusted floor rate is applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to revenues at the floor rate. Because the proposed IP rate revenues are above the floor rate revenues, no adjustment for the floor rate is necessary. Tables RDS23 and RDS24 show the DSI floor rate calculation.

2.3.10 <u>Rate Design Contra</u>. Rate design adjustments move allocated costs between classes of service, or adjust rates to account for excess revenues. Each rate design adjustment shows to which classes of service the amount of the adjustment went. What is not shown for each rate design adjustment is the complementary accounting entry showing where the adjustment came from. The RAM keeps track of all such complementary accounting. When COSA-allocated costs and rate design adjustments are summarized, it is necessary to further adjust the allocated costs by the amount of the complementary transactions. Such amounts are referred to as the rate design contra, which must be applied so that final allocated and adjusted costs to all rate classes will equal BPA's revenue requirements. *See* Table RDS40.

2.3.11 <u>Rate Design Results</u>. Table RDS41 summarizes the allocated costs and rate design adjustments for each class of service. Rate charges are calculated for each class by dividing the

2.3.12 NR Rate Revenue Deficiency Reallocation. For ratemaking purposes, an NR rate pool load of one average megawatt per year is assumed, and costs are allocated to that load. BPA has determined that the rates charged under the NR rate schedule for purchases that include energy will be the same as the rates charged under the PF Preference rate schedule. The costs allocated to the NR load are greater than the revenues forecasted, creating an NR rate revenue deficiency. Using an iterative process, this deficiency ($1.02 million) is reallocated to the PF Preference rate pool. *See* RDS50 and RDS52.

2.4 Seasonal and Diurnal Differentiation

Electric power usage and costs vary by hours of the day and monthly periods (seasons) of the year. To reflect this aspect of cost causation, BPA's allocated costs are apportioned into different seasons and hours of the day using the results of the Marginal Cost Analysis (MCA). The MCA methodology is described in the Marginal Cost Analysis Study, WP-96-FS-BPA-04. The MCA measures the costs that BPA faces as a participant in the West Coast energy market during different times of the day, week, and year. By using the results of the MCA, BPA's rates reflect the effect of West Coast market prices on BPA's marginal cost at different times of the day and in different months of the year.

Seasonal periods for generation energy are based on the six monthly pricing periods (seasons) identified in the MCA: September through December; January through March; April; May and hours run from 6:00 AM to 10:00 PM, Monday to Saturday. Light load hours are the remaining hours of the week.

Generation capacity costs are not apportioned to monthly or diurnal periods. The marginal cost of demand, which is calculated in the Marginal Cost Analysis Study, WP-96-FS-BPA-04, plus the cost of transmission revenue deficiencies is used as the power demand charge. The revenues to be recovered from the power demand charge are significantly less than the revenues to be recovered from the energy charges. Thus, to seasonally or diurnally differentiate the power demand charge would provide a much less powerful price signal than the energy charges. The administrative complexity of time differentiating generation capacity costs would outweigh the benefits from providing such a price signal. The result is a flat power demand charge for PF, IP, and NR rates across all months.

The results are presented in Tables RDS50, 51, and 52.

## 3. UNBUNDLED POWER PRODUCTS

### 3.1 Overview

Unbundled power products are those power products that are defined, priced, and available separately from BPA's power sales. Generally, BPA has unbundled (1) services provided to support customers' resources and (2) services related to changes in customers' loads. In addition

Unbundled power products are available under the PF, NR, IP, FPS, and APS rate schedules. Some of the unbundled power products that are available under these schedules were bundled into the PF, IP, and NR rates in previous years' rate proposals. Products available under the PF, NR, and IP rates (except Load Regulation, and products available under the Flexible PF or NR Rate Option) will be sold under the 1981 and 1996 Contracts at fixed rates. The charges and billing factors for products purchased under the Flexible PF or NR Rate Option will be mutually agreed to by BPA and the Purchaser, subject to satisfying an equivalent net present value revenue test and a cash flow test. Load Regulation under the PF, NR, and IP rate schedules, and ancillary services under the APS rate schedule, generally are available at downwardly flexible rates. BPA will set any discounted rates for ancillary services consistent with FERC policy. Products available under the FPS rate schedule may be sold at the FPS Contract rate or at negotiated rates.

Section 3.2 describes the rates and adjustments for the following load shaping products: Full Load Shaping, Partial Load Shaping, Industrial Exemption, and DSI Load Shaping. Section 3.2 also describes the Utility Factor, which is applied to the rate for Full Load Shaping and Load Regulation for utility purchasers under the 1981 Contracts. Section 3.3 describes the rates for the following control area services: Load Regulation, Control Area Reserves for Resources, and Control Area Reserves for Interruptible Purchases. Section 3.4 describes the rates for Energy Imbalance. Section 3.5 describes the rate for Transmission Losses. Other unbundled power products are summarized in section 3.6. Forecasted revenues from the sale of unbundled products including ancillary services are discussed in WPRDS section 5.2.3.

3.2 Load Shaping

Load Shaping is a set of four products that shift the planning risk to BPA for meeting the difference between the customer's actual and forecasted retail loads. The four load shaping products include Full Load Shaping, Partial Load Shaping, Industrial Exemption, and DSI Load Shaping. BPA has developed rates for Full Load Shaping, Partial Load Shaping, and DSI Load Shaping, and a rate to meet variations from forecast of loads covered by an Industrial Exemption. The Industrial Exemption results in an adjustment to the Full Load Shaping Utility Factor and billing factor. These products and the rates for these products are described below.

3.2.1 Full Load Shaping. Full Load Shaping shifts the planning risk to BPA for all variations between actual and forecasted retail loads above the level of the customer's resources. With Full Load Shaping, BPA will deliver additional power at the PF or NR rate to meet variations in retail load above forecast and will reduce PF and NR deliveries for variations in retail load below forecast. This product is available to utility customers under both the 1981 and 1996 Contracts with the exception of Planned and Contracted Computed Requirements customers under the 1981 Contract.

Under the 1996 Contracts, the rate for Full Load Shaping is 0.32 mills/kWh. For customers purchasing under 1981 Contracts who do not have an Industrial Exemption, the rate is adjusted by the Utility Factor. For Metered Requirements customers, the Utility Factor is the ratio of each utility's retail load to BPA deliveries. For Computed Requirements customers, the Utility Factor

The billing factor for Full Load Shaping under 1981 Contracts for Metered Requirements customers is the total amount of monthly HLH and LLH Measured Energy, which includes Measured Energy under the PF rate schedule and Measured Energy, if any, for New Large Single Loads under the NR rate schedule *less* any HLH and LLH Industrial Exemption Measured Energy. For Computed Requirements customers the billing factor is the total monthly Computed Energy Maximum, less any HLH and LLH Industrial Exemption Measured Energy. The billing factor for customers under 1996 Contracts is the customer's monthly Total Retail Load less any HLH and LLH Industrial Exemption Measured Energy. Partial Requirements customers under the 1996 Contracts may choose which months to purchase Full Load Shaping when they make energy and demand purchase commitments. For details of the calculation deriving the rate, *see* section 7.7 of the WPRDS Documentation, WP-96-FS-BPA-05A.

3.2.2 Industrial Exemption. The Industrial Exemption allows a Full Load Shaping purchaser to exclude qualifying Industrial Exemption loads from the Full Load Shaping billing factor and instead purchase load shaping on an actual use basis for that load. It is available to purchasers under both the 1981 and the 1996 Contracts. The Industrial Exemption allows a customer to exempt any single, highly predictable, separately metered industrial load from Full Load Shaping service. It is generally used with loads of 5 aMW or greater. If a customer has more than one eligible industrial load, each load will be metered, forecast, and exempted separately.

At least 2 months prior to the start of the billing month, the customer provides BPA with monthly HLH and LLH energy forecasts for each exempt industrial load. These forecasts will be used as for exemption at a subsequent date if it can demonstrate a reasonable expectation of future predictability.

The monthly forecasts also will be used to charge the customer for the variation between forecast and actual energy use. Energy taken above or below the forecast will be charged as variations at the rate of 1.16 mills/kWh. *See* section 7.7 of WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation of the rate for variations under the Industrial Exemption product.

3.2.3 Partial Load Shaping. The Partial Load Shaping product allows Planned Computed Requirements customers under the 1981 Contract and Partial Requirements customers under the 1996 Contract to purchase a specific monthly amount of Load Shaping. If the customer's retail load exceeds its forecast, BPA delivers additional power at the PF rate, but only up to the amount of Partial Load Shaping purchased by the customer. Similarly, if the customer's retail load is lower than forecast, BPA will relieve the customer's obligation to purchase power to the extent of the amount of Partial Load Shaping purchased by the customer. Customers may choose a different amount of Partial Load Shaping each month. The rate for Partial Load Shaping is $2.27 per MWh per hour of the customer's Partial Load Shaping purchase amount times the hours in the month. *See* section 7.7 of the WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation.

3.2.4 DSI Load Shaping. DSI Load Shaping allows a DSI customer under the 1996 Contract to vary monthly energy deliveries up to 15 percent above or below that month's energy purchase variations not exceeding 15 percent above that month's energy purchase commitment. The rate for DSI Load Shaping is $201 per aMW of Calculated Energy Capacity (the average amount of energy a DSI would consume at a separately metered facility when that facility is operating at full capacity); *see* section 7.7 of the WPRDS Documentation, WP-96-FS-BPA-05A.

3.2.5 Utility Factor. The Utility Factor is an adjustment that BPA applies to the rate for Full Load Shaping and Load Regulation for utility purchasers under the 1981 Contracts. The Utility Factor modifies the Full Load Shaping and Load Regulation rates to create a more direct relationship between the costs incurred by BPA for providing these services to specific customers and the actual charge assessed.

Utility Factors are developed annually for the subsequent fiscal year based on previous calendar year data provided by the customers to BPA. The Utility Factor will be based on the customer's historical annual Total Retail Load and purchases, or rights to purchase, from BPA. The Load Shaping and Load Regulation Utility Factors are calculated the same with the exception that New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract are excluded from the calculation of Total Retail Load for the Full Load Shaping products.

For a Metered Requirements customer, the Load Regulation Utility Factor equals the purchaser's Total Retail Load for the previous calendar year divided by the purchaser's previous calendar year BPA purchases. For a Computed Requirements customer, the Load Regulation Utility Factor equals the purchaser's previous calendar year Total Retail Load divided by the purchaser's dedicated resources pursuant to section 8(e) of the 1981 Contract, divided by the purchaser's previous calendar year BPA purchases.  For a Computed Requirements customer, the Load Shaping Utility Factor equals the purchaser's previous calendar year Total Retail Load, excluding New Large Single Loads served by dedicated resources pursuant to section 8(e) of the 1981 Contract, divided by the purchaser's previous calendar year Computed Energy Maximum.

A utility's Total Retail Load will be calculated by aggregating all energy (kWh) purchased and/or generated during the previous calendar year and is used to determine the customer's Utility Factor in the subsequent fiscal year.  The completed Utility Factors will be provided to the customers for each fiscal year.  Utility Factors, including Adjusted Utility Factors, will be capped at 6.0.

For customers that purchase under the 1981 Contract and have an Industrial Exemption, an Adjusted Utility Factor is used for Full Load Shaping.  The Adjusted Utility Factor is calculated each month.

For Metered Requirements customers, the Adjusted Utility Factor is (1/12 *times* the customer's Total Retail Load for the applicable calendar year *minus* the Industrial Exemption forecast for the current month) *divided by* (1/12 *times* the customer's BPA purchases for applicable calendar year *minus* the Industrial Exemption forecast for the current month).

For Computed Requirements customers, the Adjusted Utility Factor is (1/12 *times* the customer's Total Retail Load for the applicable calendar year *minus* the Industrial Exemption forecast for the

3.3 Control Area Services

The following ancillary services fall under the general category of control area services: Control Area Reserves (CAR) for Resources, CAR for Interruptible Purchases, Load Regulation, and Energy Imbalance. These products are consistent with the requirements of FERC Order 888. The rates for CAR for Resources, CAR for Interruptible Purchases, and Load Regulation are developed in a similar manner. Control area services may be provided either by a utility system that has automatic generation control (AGC) equipment or a generating plant set up to follow variations of a specific load. In the cases of CAR for Resources and Load Regulation, BPA delivers power to the customer in amounts that change automatically in response to changes in the customer’s loads or resource output during the delivery hour. These services meet the reliability standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP).

Cost Derivation for Control Area Reserve Products. The rates for Load Regulation, CAR for Interruptible Purchases, and CAR for Resources are based on the costs associated with the reserves (control reserves, spinning reserves, and non-spinning operating reserves) used to provide the products. These reserves are described below.

Operating Reserves. This is the unloaded generating capacity, interruptible load, or other on-demand rights that the customer is able to access within ten (10) minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to

Spinning Reserves. Spinning reserves are the unloaded generating capacity of a system's firm resources that is the portion of Operating Reserve that is synchronized to the power system and provides additional energy as required to be immediately responsive to system frequency. NWPP requires that each control area maintain a spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

Non-Spinning Operating Reserves. Non-spinning operating reserve is that portion of the Operating Reserve that does not meet the definition of Spinning Reserve. Generally, non-spinning operating reserve is that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. The NWPP requires that each control area maintain a non-spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

Control Reserves. Control reserves are the generating capacity of a power system that is immediately responsive to AGC control signals without human intervention. Control reserves are required to provide AGC response to load and generation fluctuations in an effective manner. In order to maintain desired compliance with NERC AGC Control Performance criteria, BPA currently keeps this requirement to a minimum of 280 MW. In the rate calculations below, the 280 MW figure was split between CAR for Resources and Load Regulation based on relative usage. *See* Table 1 of this section.

Reserves Costs. Generally, the cost of maintaining a given level of operating and control reserves personnel, and increased maintenance necessary to maintain the generating units, switching devices, and control equipment at the required level of readiness.

Because BPA does not have available data to directly derive the costs associated with reserves, BPA obtained the cost of reserves by pricing the flexibility inherent in these reserves. BPA started with a basic capacity cost of $2.09 per kW/month, which was derived from BPA's Marginal Cost Analysis Study. This cost represents the marginal cost to BPA of standing ready to serve load assuming a 1-year notice period and 5-year commitment. BPA then compared this basic product to a flexible capacity product with the following features: (1) ability to return energy in 168 hours instead of 24 hours; (2) ability to change scheduled demand amount with 30 minutes' notice; and (3) ability to change the rate of energy return with 30 minutes' notice. These additional flexibility features added another $1.79 per kW/month to the basic capacity cost. The cost for the attribute of operating reserves being available on 10 minutes' notice, $0.50 per kW/month, was added, for a total cost of $4.38 per kW/month for non-spinning operating reserves. For spinning and control reserves' additional flexibility of being available instantaneously, an additional cost of $1.00 per kW/month is added for a total of $5.38 per kW/month. *See* Table D in section 7.6 of the WPRDS Documentation, WP-96-FS-BPA-05A.

The cost of each reserve ($5.38 per kW/month for Spinning reserves and $4.38 per kW/month for Non-spinning reserves) is applied to the reserve requirement for each type of reserve. The cost of each reserve is presented in Table 1.

peak efficiency and the actual output of the generator on an instantaneous basis. BPA measured the costs of efficiency losses on the hydro system using a cycle gas turbine as a proxy. The efficiency loss is measured as the difference between the heat rate at 100 percent operating capability and the heat rate at reduced operating levels. For the purposes of calculating losses, the heat rate was assumed reduced by 1 percent to reflect BPA's estimate of hydro efficiency losses. Using BPA's January 1996 gas price forecast, the cost of efficiency losses for each reserve is calculated by multiplying the difference in heat rates as measured by the price of gas. The costs of efficiency losses are included in the costs of spinning reserves and control reserves.

**Table 1: Cost of Reserves for Control Area Services**

| Reserve | Column A<br>Reserve<br>Requirement<br>(percent) | Column B<br>Cost of<br>Reserves[1/]<br>($/kW/mo.) |
|---|---|---|
| Thermal | | |
| Operating Reserves | 7.0 | $0.34 |
| Non-Spinning[2/] | 3.5 | $0.15 |
| Spinning | 3.5 | $0.19 |
| Hydro | | |
| Operating Reserve | 5.0 | $0.25 |
| Non-Spinning[2/] | 2.5 | $0.11 |
| Spinning | 2.5 | $0.14 |

1/ The levelized costs of Spinning Operating Reserves shown in Column B are derived by multiplying the reserve requirement by $5.38 per kW/mo plus the cost of efficiency losses (where noted).

2/ The levelized costs of Non-Spinning Operating Reserves shown in Column B are derived by multiplying the reserve requirement by $4.38 per kW/mo.

3/ 280 MW of control reserve are split between generation following and load following. Ninety percent (252 MW) of control reserves are deemed to be used in controlling variations of load, and the remainder (28 MW) are deemed to be used in controlling variations in generation. 252 MW is 3.58 percent of load under BPA's control (7033 MW). 28 MW is 0.31 percent of total generation in BPA's control area (9000 MW). The costs in column B are derived from multiplying the relevant percentage by $5.38 per kW/mo plus the cost of efficiency losses of $0.012 per kW/mo.

3.3.1 <u>Load Regulation</u>. Load Regulation is the instantaneous (second-to-second) regulation of the supply of power that BPA provides to follow the instantaneous variations in customers' loads throughout the hour. Load Regulation is available under the PF, IP, NR, and APS rate schedules.

For utility purchasers under the 1981 Contracts, the rate for Load Regulation is adjusted by a utility-specific factor (Utility Factor, described in section 3.2.5, above). The adjusted rate for a Metered Requirements customer is applied to the customer's Measured Energy purchased under the PF or NR rate schedule. For a Computed Requirements customer, the adjusted rate is applied

This product is provided for all loads in the BPA control area. Customers served by transfer also receive Load Regulation services and will be charged the applicable rate. The Load Regulation rate is bundled as part of the PF Composite Rate.

The rate for Load Regulation is 0.28 mill/kWh and is based on BPA's cost of providing the portion of control reserves to follow loads located in BPA's control area. As shown on Table 1, this rate is equal to the cost of control reserves for load of $0.20 per kW/month, which is converted to mills per kWh to derive the rate of 0.28 mill/kWh. *See* Table A in section 7.6 of the WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation. BPA also may offer discounted rates for Load Regulation, consistent with FERC Order 888.

3.3.2 <u>Control Area Reserves for Resources</u>. CAR for Resources, which are available under the APS-96 rate schedule, are the control area services necessary to support generation located in BPA's control area. CAR for Resources provides for both the generation following requirements of the resource and a resource's operating reserve obligation for the remainder of the delivery hour. To reflect the differing amounts of operating reserves that the NWPP Operating Reserve Sharing Program requires BPA to carry for different resource types, the rate for CAR for Resources contains two rates -- one for hydroelectric resources and one for non-hydroelectric resources. In addition, the rates are available for full or partial service. Full service will automatically be provided, unless BPA agrees to provide partial service to meet the resource owner's control area reserve obligations.

following, and spinning and non-spinning operating reserves required to back up hydroelectric resources. As shown on Table 1, the cost of providing the generation portion of control reserves is $0.02 per kW/month. The cost of providing spinning and non-spinning operating reserves is $0.25 per kW/month. The rate for full service is the sum of these costs. *See* Table A in section 7.6 of the WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation.

<u>Control Area Reserves for Non-Hydroelectric Resources</u>. The rate for (full service) CAR for Non-Hydroelectric Resources is $0.36 per kW/month of the purchaser's non-hydroelectric resource capability in BPA's control area. This rate is based on the cost of control reserves, and spinning and non-spinning operating reserves required to back up a thermal resource. As shown on Table 1, the cost of providing the generation portion of control reserves is $0.02 per kW/month. The cost of providing spinning and non-spinning operating reserves is $0.34 per kW/month. The rate for full service is the sum of these costs. *See* Table A in section 7.6 of the WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation.

The rates for partial service, regardless of resource type, are $5.39 per kW/mo for spinning operating reserves, $4.38 per kW/mo for non-spinning operating reserves, and $0.02 per kW/mo for generation following.

3.3.3 <u>Control Area Reserves for Interruptible Purchases</u>. This product, which is available under the APS-96 rate schedule, provides non-spinning operating reserves for scheduled interruptible deliveries of energy to BPA's control area where the transmission or energy components are associated with non-spinning operating reserves of $2.09 per kW/month converted and rounded to 2.87 mills per kWh. The $2.09 per kW/month capacity cost reflects a lower control capability cost than was used in estimating the costs of other control area reserves, because BPA provides this product on an "as available" basis only. BPA also may offer discounted rates for this service, consistent with FERC Order 888. *See* Table A in section 7.6 of the WPRDS Documentation, WP-96-FS-BPA-05A, for details of the calculation.

3.4 <u>Energy Imbalance</u>

Energy Imbalance Service, which is available under the APS-96 rate schedule, is provided when there is a difference between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with the transmission of power to a load located in BPA's control area or from a generation resource located within BPA's control area. BPA allows an hourly Energy Imbalance Band of +/- 1.5 percent of the schedule (with a minimum band of +/- 1 megawatt) to be applied hourly to any energy imbalance that occurs as a result of the scheduled transmission to loads or from resources located in BPA's control area.

The rates for Energy Imbalance are designed to discourage deviations that occur from the transmission of power scheduled to loads and/or from resources in BPA's control area. The energy rates for Positive Deviations (for payment by the purchaser) and energy credit for Negative Deviations (for payment by BPA to the purchaser) within the Energy Imbalance Band are equal to 100 percent of BPA's levelized marginal cost of firm energy. The demand rate for

Imbalance Band is equal to BPA's adjusted marginal cost of generation capacity. The energy rates for Negative Deviation outside the -1.5 percent Energy Imbalance Band are equal to 50 percent of BPA's marginal cost. BPA also may offer discounted rates for this service, where applicable, consistent with FERC Order 888. *See* the MCA, WP-96-FS-BPA-04A, Table 10, for the marginal costs of firm energy and generation capacity.

3.5 <u>Transmission Losses</u>

Transmission losses are the real power losses associated with the transmission of power over the FCRTS. The rate for transmission losses, which is available under the APS-96 rate schedule, is 22.80 mills per kWh and is derived from the generation costs included in Bonneville's Average System Cost (BASC) divided by total firm sales. This rate applies to customers who make an annual commitment to purchase losses from BPA pursuant to the applicable Agreement. BPA also may offer discounted rates for this service, consistent with FERC Order 888. No revenues are forecasted from sales under this rate.

3.6 <u>Other Unbundled Products</u>

3.6.1 <u>Unbundled Products Available Under the FPS-96 Rate Schedule</u>. The FPS-96 rate schedule contains four categories of service: Firm Power; Supplemental Control Area Services; Shaping Services; and Reservation and Rights to Change Services. Under each of these general categories there may be many unbundled products and services available. The products and

<u>Firm Power</u>. Firm Power is made available at the FPS-96 rate at BPA's discretion. Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Firm Power is guaranteed to be continuously available to the purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. Firm Power may be used to meet the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP) for Operating Reserves.

<u>Supplemental Control Area Services</u>. Supplemental control area services are available to support control areas of utilities or resource owners other than BPA, and their control area regulating margin and spinning reserve obligations.

<u>Shaping Services</u>. Shaping Services are services provided to shape the output of the purchaser's resource or purchase to its load. Shaping Services may be provided over any time period and may include advance delivery by BPA of the power to load.

<u>Reservation and Rights to Change Services</u>. The FPS-96 rate schedule contains unbundled products and services that describe how power may be reserved in advance, requested and delivered. The FPS-96 rate schedule also may be used to purchase rights to change the service provisions of the purchaser's agreement.

any amount of non-Federal service the customer identifies at the time it elects this curtailment option. Under this product, BPA relieves the customer of its take-or-pay obligation for generation demand, transmission demand, HLH energy, LLH energy, and the use-of-facilities charge for any such curtailed amount. The customer pays BPA a fixed curtailment fee in mills per kilowatthour for the curtailed amount. The customer must give BPA advance notice of the curtailment. The amount curtailed must be excess firm energy, which is firm energy that would have been delivered to the customer for service to its plant load but is excess due to a reduction in the actual plant load. The product does not allow reductions in BPA load that are replaced by non-Federal power.

The curtailment charge is 4.95 mills per kilowatthour of Curtailed Energy. The curtailment charge reflects the reduced revenues to BPA from selling in alternative markets the excess firm energy and firm transmission resulting from DSI load loss. For details of the calculation deriving the rate, *see* section 7.10.1 of the WPRDS Documentation, WP-96-FS-BPA-05A.

<u>DSI Non-Take-or-Pay Option.</u> This option allows a DSI customer, for a fee, to purchase power under the IP rate without a take-or-pay obligation. To be eligible for this option, the customer must sign a 1996 Contract for specified amounts of non-take-or-pay load. Under this option, BPA relieves the customer of its take-or-pay obligation for generation demand, HLH energy, and LLH energy. As with the Fixed Curtailment Fee, the amount curtailed must be excess firm energy. The customer will not be relieved of take-or-pay obligations for reductions in BPA load that are replaced by non-Federal power.

selling in alternative markets the excess firm energy resulting from DSI load loss. For details of the calculation deriving the rate, *see* section 7.10.2 of the WPRDS Documentation, WP-96-FS-BPA-05A.

## 4. RATE DESIGN CHANGES

### 4.1 Five-Year Firm Power

In the 1996 rate proposal BPA is offering Priority Firm Power, New Resource Firm Power, and Industrial Firm Power at 5-year rates. Other products, such as Full and Partial Load Shaping and Load Regulation, also are offered under the proposed 5-year rate schedules. These and other unbundled products are described in WPRDS chapter 3, above. Customers will be able to choose to purchase power at the rates specified in the 1996 rate schedules for up to 5 years. BPA retains the discretion to change its rates before the end of the 5-year period, but if a customer contractually commits to purchase under a 5-year rate schedule for a specific period of time, the customer’s rates for the products purchased under that commitment will not change for the purchase period. Participants in the residential exchange also may continue to receive benefits based on the PF-96 rate schedule if BPA can obtain some corresponding cost certainty for the utility’s Average System Cost.

BPA’s modeling for the 1996 rate proposal, as described in WPRDS sections 2 and 5, determines rates for the 5-year test period. The effective period of the 1996 rates is proposed to be FY 1997 power rate schedule includes a reference to the appropriate, separate transmission rate schedules. Billing factors are described in sections 4.2 and 4.3, below.

4.2 Energy Billing Factors

The energy billing factors for the PF-96, IP-96, and NR-96 rate schedules differ from those in the 1993 final rate schedules. The energy billing factors are designed to reflect the purchase relationships described in the 1981 and 1996 Contracts, the new products BPA is proposing, and the intention to make the billing factors for the 1981 and 1996 Contract purchasers as consistent as possible. The following discussion focuses on the PF and NR rate schedules.

Metered Requirements customers purchasing under the 1981 Contract and Full Requirements purchasers under the 1996 Contract will be billed on their respective Heavy Load Hour (HLH) and Light Load Hour (LLH) Measured Energy.

For Computed Requirements customers purchasing under the 1981 Contract, the billing factors are the Purchaser’s respective HLH and LLH Measured Energy. These customers also are subject to an Availability Charge, which mitigates BPA’s revenue loss when these customers purchase less energy from BPA than BPA is contractually obligated to provide. The Availability Charge is described in more detail in section 4.12, following, and in section 7.8 of the WPRDS Documentation.

Energy in the GRSPs, WP-96-A-02, Appendix. Minimum Contract Obligation accounts for authorized deviations and any other contractually specified adjustments to the customer's monthly HLH or LLH Contract Obligation. *See* the definition of Minimum Contract Obligation in the GRSPs, WP-96-A-02, Appendix. If a Partial Requirements customer has the contractual right to displace its PF or NR energy purchases from BPA, the customer is billed on its respective HLH and LLH Adjusted Measured Energy. Partial Requirements customers that have the contractual right to displace PF or NR energy purchases also are subject to the Availability Charge, unless otherwise agreed to by BPA and the Purchaser. The Availability Charge is discussed in more detail in section 4.12.

The energy billing factor for customers purchasing under the NR rate to serve New Large Single Loads also is the Purchaser's Measured Energy, unless BPA and the Purchaser agree to bill based on a contracted amount of energy.

4.3 Demand Billing Factors

The demand billing factors for the PF-96, IP-96, and NR-96 rate schedules differ from those in the 1993 final rate schedules. Like the energy billing factors, the demand billing factors are designed to reflect the purchase relationships described in the 1981 and 1996 Contracts, the new products BPA is proposing, and the intention to make the billing factors for the 1981 and 1996 Contract purchasers as consistent as possible. Most of the demand billing factors are calculated using the Purchaser's Measured Demand at the time of the Monthly Federal System Peak Load

Metered Requirements customers purchasing under the 1981 Contract and Full Requirements purchasers under the 1996 Contract will be billed on their Measured Demand during the hour of the Monthly Federal System Peak Load.  The demand billing factor for customers purchasing under the NR rate to serve New Large Single Loads also is the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load, unless mutually agreed by BPA and the Purchaser.

For Computed Requirements customers who have not waived part of their Computed Maximum Requirement (CMR), the billing factor for demand is the Purchaser's highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the Purchaser's points of delivery (PODs).  Computed Requirements customers who have not waived part of their CMR also are charged for reserving power demand.  The Power Demand Reservation Charge is described in section 4.13, following, and in section 7.9 of the WPRDS Documentation.  The billing factor for Computed Requirements customers who do waive part of their CMR is the Purchaser's CMR minus the declared megawatt amount waived.  Because a customer that waives part of its CMR is billed on its contractual entitlement, it is, in effect, paying for its entire contractual entitlement, including any reserved demand, through the demand charge. Thus, no separate charge for reserving demand is needed.

Partial Requirements customers purchasing under the 1996 Contract will be billed for demand on the greater of:  (1) the Purchaser's Measured Demand that occurs during the hour of the Monthly

## 4.4 Unauthorized Increase Charge

In previous rate proposals BPA has included an Unauthorized Increase Charge in most firm power rate schedules as a penalty for customers that take more power than they are contractually entitled to take. The 1996 rate proposal includes two types of adjustments for deliveries that are different from contractual entitlement, the Deviation Adjustment and the Unauthorized Increase Charge. Further details on these charges are found in the GRSPs, WP-96-A-02, Appendix.

The Deviation Adjustment applies to Partial Requirements customers purchasing under the 1996 Contract and may apply to Full Requirements customers purchasing under the 1996 Contract. Amounts of authorized deviations, for which the customer is not charged a penalty, are specified in the customer's power sales contract. Unauthorized negative deviations are treated as take-or-pay amounts, added to the customer's Measured Energy, and billed at the rate applicable to the particular customer. Unauthorized positive deviations are charged the Unauthorized Increase Charge.

If specified in the applicable rate schedule, the Unauthorized Increase Charge will be applied for any purchaser taking demand and energy in excess of its contractual entitlement. The demand charge for unauthorized demand increases is the demand charge from the applicable power rate schedule. The energy charge for unauthorized energy increases is 100 mills per kilowatthour. Unlike the Unauthorized Increase Charge for the 1995 rate proposal, the proposed Unauthorized Increase Charge is not seasonally differentiated.

4.5 Composite Rate

All Full Requirements utilities purchasing under the 1996 Contract and Metered Requirements utilities purchasing under the 1981 Contract that have annual retail loads of 25 aMW or less, who agree to purchase for 5 years from BPA under the PF-96 rate schedule, are eligible to purchase at the composite rate. The composite rate is a weighted average Priority Firm rate that bundles into a single rate the various rate components included in the PF-96 rate schedule for power sold to these customers. The composite rate is the average expected revenues from these customers for sales of firm power (including demand and energy components), Full Load Shaping, and Load Regulation. Customers will be charged for transmission services under the appropriate transmission rate schedule.

The Composite Rate was developed based on 5-year forecasted loads for Full and Metered Requirements utilities whose annual retail loads were forecasted to be 25 aMW or less, except for irrigating utilities. A ratio was applied to the individual demand amounts to convert the noncoincidental demand to coincidental demand. The individual power components of the PF-96 rate were applied to the monthly load forecast for each year of the 5-year rate period to yield the expected total revenues for each year. The expected total revenues from these customers for the five fiscal years were added together, as were the projected total gigawatthours. The sum of the total revenues for the 5-year period divided by the total gigawatthours yields the composite rate.

4.6 PF Exchange Rate

additional costs are allocated to the PF Exchange rate due to the section 7(b)(2) rate test. The PF Exchange rate includes rate components similar to the rate components of the PF Preference rate. The PF Exchange demand charge is the same as the PF Preference demand charge. The PF Exchange energy charges are seasonally differentiated the same as the PF Preference energy charges.

Unlike the PF Preference rate, the PF Exchange rate contains a single energy rate for all hours. That is, the PF Exchange rate does not contain HLH and LLH energy charges. The PF Exchange rate also includes charges for Load Shaping, Load Regulation, and transmission service under the Network Integration (NT) rate, which are also included in the services provided PF Preference customers.

Finally, the PF Exchange rate includes an adjustment (or adder) for the section 7(b)(2) rate test. The section 7(b)(2) rate test is described in the Section 7(b)(2) Rate Test Study and Documentation (WP-96-FS-BPA-07 and WP-96-FS-BPA-07A).

## 4.7 <u>Firm Capacity Without Energy</u>

Firm capacity without energy is a product that allows customers to purchase power from BPA during HLH and requires return of the associated energy within 24 hours. Firm capacity without energy is available under the PF-96 and NR-96 rate schedules for Computed Requirements customers purchasing under the 1981 Contract. Firm capacity without energy also is available

The rates for firm capacity without energy under the PF-96 and NR-96 rate schedules are calculated by summing BPA's annual generation demand charge of $0.87 per kilowatt and the differentials between HLH and LLH energy charges for each of the six energy seasons for each rate schedule. The differentials between HLH and LLH energy charges for the PF rate are calculated using the energy rates as published in the PF-96 rate schedule. The differentials between HLH and LLH energy charges for the NR rate are calculated using the Total Allocated Costs NR rate; *see* Table RDS52 in section 3.5 of the WPRDS Documentation. For both the PF and the NR capacity rate calculations, each season's energy rate differential in mills per kilowatthour is converted to dollars per kilowatt-month assuming a standard 50-hour per week capacity product and an average number of weeks per month. *See* section 7.1 of the WPRDS Documentation, WP-96-FS-BPA-05A.

4.8 <u>Energy Return Surcharge</u>

The Energy Return Surcharge applies to customers purchasing capacity under the PF and NR rate schedules who return energy during offpeak hours to BPA at a rate greater than 60 percent of amount of capacity purchased. The methodology for calculating the surcharge is the same as the methodology used in the 1993 final rate proposal except that the surcharge for the 1996 rate proposal is calculated for the six energy seasons. The energy return surcharge for each season is a mills per kilowatthour charge for energy returned during a single offpeak hour at more than 60 percent of the difference between a purchaser's Billing Demand and Computed Average Energy Requirement for the billing month.

60 percent of the amount taken during onpeak hours. Thus, any energy returned offpeak at a rate of return greater than 60 percent of the difference between the Billing Demand and the Computed Average Energy Requirement is assessed a charge equal to 2.44 mills per kWh during September - December; 2.42 mills per kWh during January - March; 3.27 mills per kWh during April; 3.79 mills per kWh during May - June; 4.11 mills per kWh during July; and 4.91 mills per kWh during August.

To derive the energy return surcharge for each season, the seasonal amounts of 50-hour sustained peak reduction due to an increased rate of return from 60 to 80 percent are valued at the PF-96 demand charge, plus $1.539 kW/mo. for Network Integration transmission (NT) service. The seasonal hourly surcharges are the quotients of these monthly values and the amount of energy associated with a one-percent rate of return per month, given an 8-hour day limitation for peaking service. *See* section 7.1 in the WPRDS Documentation, WP-96-FS-BPA-05A.

4.9 Phase-In Mitigation

The Phase-In Mitigation applies to Full Requirements Preference customers purchasing under the 1996 Contract and Metered Requirements Preference customers purchasing under the 1981 Contract. Eligible customers would be those who choose to purchase all of their power from BPA under one or more of BPA's 5-year rate schedules, and face an increase in their FY 1997 rates greater than 9 percent. The Phase-In Mitigation eligibility criteria, determination of phase-in level, and applicability of the rate adjustment appear in the GRSPs, WP-96-A-02, Appendix include generation and transmission costs) to the customer's 1996 expected purchases. The second number is the customer's expected costs calculated by applying all applicable 1996 PF and transmission charges to the customer's 1996 expected purchases. If the difference between the two numbers, divided by the first number, is greater than 9 percent, rounded to the nearest tenth of a percent, the customer may notify BPA to phase in the 1996 rate increase.

For customers for whom BPA consents to phase in the 1996 rate increase, the calculation described above will be performed monthly so as to limit the monthly increase in the customer's bill to 9 percent the first year, an additional 9 percent the second year (yielding a maximum of 18 percent the second year), and so on for the 5 years of the rate period.

4.10 Low Density Discount

Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on retail rates of BPA's customers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such customers. Such customers are utilities with low system densities, such as rural electric cooperatives, with high distribution costs resulting from sparsely populated service areas. Estimates of annual Low Density Discount (LDD) percentages for LDD-receiving utilities assuming BPA's proposed new methodology are provided in section 7.2 of the WPRDS Documentation, WP-96-FS-BPA-05A. The LDD principles, eligibility criteria, and discount calculation table appear in the GRSPs, WP-96-A-02, Appendix.

determined based on data submitted by the purchaser based on the purchaser's entire electric utility system in the Pacific Northwest.  For purchasers with service territories that include any areas outside the Pacific Northwest, BPA shall compile data submitted by the purchaser separately on the purchaser's system in the Pacific Northwest and on the purchaser's entire electric utility system inside and outside the Pacific Northwest.  BPA will apply the eligibility criteria and discount percentages to the purchaser's system within the Pacific Northwest, and where applicable, also to its entire system inside and outside the Pacific Northwest.  The purchaser's eligibility for the LDD will be determined by the lesser amount of discount applicable to its Pacific Northwest system or to its combined system inside and outside the Pacific Northwest.  BPA, in its sole discretion, may waive the requirement to submit separate data for a customer with a small amount of its system outside the Pacific Northwest.  The discounts under each ratio range from zero to five percent, in half-percent increments.  The discounts from the two ratios are added together to determine the total discount to that customer's purchases under the PF rate.  The LDD for any utility is capped at 7 percent.

The new discount for any eligible utility will be ramped in from the existing discount.  No eligible utility will experience more than a one-half percentage point change (positive or negative) in its LDD beginning October 1, 1996, and each succeeding fiscal year, until the LDD percentage of the revised methodology, capped at 7 percent, is attained.  If a utility fails to satisfy the initial eligibility criteria, however, the discount will be zero and will not be ramped in from the existing discount.

Application of the discount for FY 1996 can be seen in section 4 (FY 1996 Revenue Forecast) of the WPRDS Documentation (WP-96-FS-BPA-05A); and for the rate case test period in section 3.6 (Revenue Forecast at Proposed Rates) and section 3.7 (Revenue Forecast at Current Rates) of the WPRDS Documentation (WP-96-FS-BPA-05A).

4.11 Irrigation Discount

The Irrigation Discount was included in BPA's 1995 rate proposal. It provided a discount to the PF and NR rates for qualifying irrigation load during the months of April through October. Participating utilities were required to pass on the discount, in its entirety, to qualifying irrigation end-users.

BPA is proposing to eliminate the irrigation discount. As noted in WPRDS section 1.3, BPA is revising its rate design to reflect cost causation and provide price signals that will result in a more efficient use of the generation and transmission systems. The combination of the new rate design, including seasonal and diurnal pricing of energy, supports the elimination of the irrigation discount.

4.12 Availability Charge

In past PF and NR rate schedules, including the 1993 final rate schedules, the Availability Charge

Availability Charge for the 1996 final rate proposal is stated as a mills per kilowatthour charge. *See* Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128. The Availability Charge is designed to mitigate BPA's revenue underrecovery associated with customers purchasing less energy than they are contractually entitled to purchase by displacing their energy purchases from BPA with energy from other suppliers or with their own nonfirm energy. Displacement of demand purchases is accounted for in the Power Demand Reservation Charge, which is discussed in the following section, 4.13.

The Availability Charge is designed so that the portion of the energy rate that varies with energy purchases, the variable component of the energy charge, is less than the expected price of gas or is equal to the revenues BPA expects to receive from selling any displaced PF power at nonfirm energy rates. To implement the Power and Transmission Partial Settlement Agreement, the Availability Charge is set at 7.00 mills per kWh for the months September through December, and 8.00 mills per kWh for the months January through March. At this level, the Availability Charge protects BPA's revenue recovery when customers elect, because of low gas prices, to purchase less than they are contractually entitled to purchase. Moreover, the Availability Charge in the months September through March provides greater revenue protection than the Availability Charge in BPA's 1993 final rate schedules against the possibility that water and market conditions in 1995 would reoccur.

In the other months, March through August, the Availability Charge is calculated based on the seasonal differences in revenue BPA would receive by selling customers energy at the PF or NR

September through March. Capping the March and August Availability Charge provides a smooth transition between the fall and winter months (September through March) and the fish flow months (May through July).

In the months May through July, the hydrosystem has abundant energy due to spring runoff and fish flow requirements imposed on the hydrosystem. In those months the level of the Availability Charge protects BPA's revenues when customers displace their PF purchases due to both low gas prices and above average water conditions. The Availability charge is 4.99 mills per kWh in the months May through June, and 4.60 mills per kWh in July.

Without the 7.0 mills per kWh and 8.0 mills per kWh cap on the Availability Charge stemming from the Power and Transmission Partial Settlement Agreement, the charge in the months August through April would have been higher to reflect the interaction between low gas prices and hydro conditions in the Pacific Northwest. Without the Availability Charge cap, the charge would have been 9.24 mills per kWh for the months September through December, 11.32 mills per kWh for the months January through March, 12.36 mills per kWh for April, and 7.71 mills per kWh for August. *See* section 7.8 of the WPRDS Documentation.

For Computed Requirements customers purchasing under the 1981 Contract, the billing factor for the Availability Charge is the Purchaser's Computed Energy Maximum (CEM) minus the Purchaser's Measured Energy. The billing factor for the Availability Charge for Partial Requirements customers is the sum of the Purchaser's Monthly Minimum HLH and LLH

## 4.13 Power Demand Reservation Charge

The Power Demand Reservation Charge replaces the demand ratchet in the 1993 final rate schedules and compensates BPA for its obligation to serve Computed Requirements customers' Heavy Load Hour contractual entitlement. Under the 1981 Contract, Computed Requirements customers are entitled to purchase the greater of their Computed Peak Requirement or their Computed Average Energy Maximum during BPA's HLH. The greater of these two is called Computed Maximum Requirement (CMR).

The Power Demand Reservation Charge is $0.67 per kilowatt per month. The Power Demand Reservation Charge has two cost components. The first is the cost of holding capacity resources in reserve, and the second is the cost underrecovery due to customers displacing their peak purchases from BPA. The calculation of the Power Demand Reservation Charge is described in more detail in section 7.9 of the 1996 Final WPRDS Documentation, WP-96-FS-BPA-05A.

The billing factor for the Power Demand Reservation Charge is the difference between the purchaser's CMR and the Purchaser's highest monthly HLH Measured Demand. If a customer takes its entire HLH contractual entitlement, its CMR, the effective charge is zero for the Power Demand Reservation Charge. However, some customers' CMR is greater than what they need during the HLH. Customers can elect to waive a portion of their CMR. For customers that elect to waive part of their CMR, the separate Power Demand Reservation Charge does not apply.

# 5. REVENUE FORECAST

This section describes the revenue forecast prepared for BPA’s 1996 final rate proposal, and presents the results of that forecast. The risk analysis is described in WPRDS section 6 and in section 6 of the WPRDS Documentation, WP-96-FS-BPA-05A.

## 5.1 Overview

The revenue forecast is BPA's expected level of sales and revenue for the rate period, FY 1997 through FY 2001. The revenue forecast applies rates to various forecasts of sales and loads. However, since the firm load forecast assumes critical (i.e., 1930) water, and streamflows are usually greater than critical, the revenue forecast reflects the effect on BPA’s revenues of greater-than-critical streamflows. The revenue forecast is based on the average of 50 historical water conditions.

BPA prepares two types of revenue forecasts: (1) revenues forecasted using current rates; and (2) revenues forecasted using proposed rates. These revenue forecasts are used to determine whether rates are adequate to meet cost recovery requirements. The revenue test is described in the Revenue Requirement Study (WP-96-FS-BPA-02). The rates placed in effect October 1, 1995, are used in the calculation of forecasted revenues at current rates for FY 1997 through FY 2001. The proposed rates are developed in the WPRDS, based on the loads expected if the final rate proposal is adopted and applied to those loads whose rates are affected.

## 5.2 Sources of BPA's Revenues

Most of BPA's expected revenues are based on power sales to PF and IP customers at the rates established in the WPRDS. BPA also derives revenues from other sources. For instance, BPA receives revenues from power sales where the rates are formula rates specified by contract, such as the WNP-3 exchange rate, from existing contractual surplus firm power sales, and from the Supplemental and Entitlement Capacity contract rates. In addition, BPA expects to receive revenues from nonfirm or economy energy sales, and from unbundled power products that BPA is making available to customers. BPA also expects to receive revenues from its other non-power functions, such as transmission services and energy services. Finally, BPA expects to receive revenue credits from the U. S. Treasury to offset expenses of fish recovery programs. Examples of some of these revenue sources are briefly described below.

5.2.1 Contractual Formula Rates. Some of BPA's contracts include contractually specified formula rates. These rates are set based on a variety of factors. Some of the formula rates contain a base rate that is adjusted based on specified escalators. For instance, the contract rates with Puget Sound Power and Light; the Modesto-Santa Clara-Redding Power Agency; Burbank, Glendale, and Pasadena; Washington Water Power; Anaheim; and Riverside all escalate based on increases in the PF rate. The Portland General Electric capacity sales contract rate escalates with increases in the NR rate. The Palo Alto contract and various others include a fixed rate. The Pacific Power and Light contract rate escalates with increases in Bonneville's average system cost (BASC). The Southern California Edison contract rate is tied to the prices of gas and oil, and the

BPA also has a contractual arrangement to sell power to four IOUs that were participants in the WNP–3 nuclear plant.  Under the terms of the WNP–3 Settlement Exchange Agreement of 1984, BPA agreed to sell an amount of power to these utilities equivalent to what they would have received from WNP–3 had BPA not indefinitely postponed completing construction of that plant. The agreement specifies a rate equivalent to the O&M costs of three surrogate nuclear plants. BPA estimates that the rates applicable to such sales will be 32.87 mills per kWh in FY 1997, 34.62 mills per kWh in FY 1998, 36.0 mills per kWh in FY 1999, 37.53 mills per kWh in FY 2000, and 39.21 mills per kWh in FY 2001.

5.2.2 Sales of Excess Nonfirm Energy and Short-term Firm Power.  As noted above, for ratemaking purposes BPA projects firm loads assuming critical (i.e., 1930) water.  However, in most years, streamflows are greater than critical.  Streamflows in excess of critical water result in additional energy that BPA sells in the nonfirm energy market.  The revenue forecast reflects the effect on BPA's revenues of greater-than-critical streamflows.  Streamflow in excess of critical water affects the revenue forecast by increasing economy energy sales, reducing sales to generating public utilities, and influencing incidental wheeling revenues.

In additional to nonfirm energy, BPA may sell short-term excess firm energy.  For this rate filing, BPA assumes that it will be able to market about 400 aMW of firm power at 21.3 mills/kWh.  In addition, to reflect the expected benefits of changes in fish recovery operations which were not modeled, but are expected to be realized during the rate period, nonfirm revenues were increased by $11 million per year, and purchased power expenses were decreased by $11 million per year.

conditions, excess firm power is sold at expected prices above the expected NF rate, but most of the time this power is expected to be sold at the same rate as nonfirm energy.

BPA's NF rate schedule allows for prices above and below the average cost of nonfirm energy. BPA’s FPS rate, for sales of firm power, also is a flexible rate. Forecasts for ratesetting purposes of nonfirm energy and short-term excess firm power sales and prices are modeled on a monthly basis using the Nonfirm Revenue Analysis Program (NFRAP). The NFRAP is discussed in WPRDS section 5.4.1. Revenues from nonfirm energy and short-term firm power sales depend on supply and demand conditions. The NFRAP compares the various supply conditions with expected demand conditions to estimate sales and revenues.

5.2.3 Unbundled Power Products. There are two revenue categories for unbundled power products: 1) revenues from unbundled requirements products sold under the PF, IP, and NR rate schedules, include Load Shaping (both full and partial) and Load Regulation; and 2) revenues from unbundled products and ancillary services sold under the FPS and APS rate schedules, such as Control Area Reserve services (for hydro, thermal, and interruptible power), Shaping Services (also referred to as storage or Load Factoring), and Load Regulation. Revenues from unbundled Load Shaping products sold under the PF, NR, and IP rate schedules are expected to be about $16 million per year. Revenues from the sale of Load Regulation service with requirements service total about $14 million per year. Revenues from the sale of unbundled requirements products can be found in section 3.6 of the WPRDS documentation (WP-96-FS-BPA-05A). Revenues from the sale of other power unbundled products and ancillary services are expected to

5.2.4 Pacific Northwest Coordination Agreement (PNCA) Activity. Revenues from PNCA transactions consist primarily of Interchange sales, transmission, and storage fees. Revenues from these transactions are shown in the WPRDS Documentation (WP-96-FS-BPA-05A). These revenues are identified as Interchange energy and represent a major component of Other Power Services. Revenues from Interchange energy sales, the largest revenue component from PNCA transactions, are projected to be $25.7 million per year. This amount is approximately equal to the projected expense of Interchange energy purchases. Revenues from all other PNCA transactions (primarily from storage and transmission of power for other PNCA parties) typically average about $2 million per year.

5.2.5 Excess Federal Power due to Reductions in Firm Load, and Operations for Fish and Wildlife. BPA expects additional revenues due to recent legislation to remove certain marketing restrictions from the sale of excess firm power created by reductions in firm loads and operations for fish and wildlife. Expected revenues from power due to reductions in firm load or power generated for fish and wildlife are projected to be about $26 million per year. Of the $26 million, removing the prohibition on some sales for resale by others is expected to generate $11 million per year. Another $10 million is expected from slightly higher prices for short-term FPS sales. The other $5 million per year is associated with other marketing restrictions that the legislation removed. This $26 million in revenue is shown under the category labeled Miscellaneous Generation Revenue, because of an inability to model the impacts of these changes directly. Under current rates BPA projects 3,574 aMW of excess power due to load loss and fish operations. Under proposed rates, expected excess power from load loss and fish operations is

FS-BPA-05A. Revenues from various energy services agreements are expected to total about $103 million over the rate period.

5.2.7 Wheeling. Revenues from Network and Southern Intertie uses by non-Federal wheeling are forecasted as described below. Firm energy portions of those forecasts (from Integration of Resources and Southern Intertie-B rate service) are based on projected use from firm wheeling agreements. Nonfirm wheeling forecasts for non-Federal sales to California and other incidental revenues, such as nonfirm imports from Canada or PNW utilities, are forecast based on historical occurrences. The Revenue Forecast Model and the RAM use the wheeling forecasts developed in the Transmission Rate Design Study (WP-96-FS-BPA-07) for the rate test period.

5.2.8 Other Sources. In addition to the above revenues, BPA expects to receive credits from the Treasury to offset fish recovery program costs. These credits are recorded as revenues under the heading §4(h)(10)(c) revenues and Fish Cost Contingency Fund revenues. These average about $60 million and $24 million per year, respectively, over the rate period. BPA also expects to receive about $9 million in the form of credits the Corps of Engineers and Bureau of Reclamation receive as payments from owners of downstream hydro projects to compensate for the benefits received from upstream Corps and Bureau projects. This year BPA is projecting about $2.6 million per year from the disposition of property assigned to the generation and transmission functions. Finally, BPA expects to receive almost $17 million annually in the form of credits from the Treasury to compensate for payments to the Colville tribe.

energy loads of PF, IP, NR, and FPS sales, and non-Federal power (wheeling). The energy load forecasts used in this rate proposal are documented in the Loads and Resources Study (WP-96-FS-BPA-01) and accompanying Documentation Volumes 1 and 2 (WP-96-FS-BPA-01A and WP-96-FS-BPA-01B). Peak load forecasts for transmission of Federal and non-Federal power are described in the Transmission Rate Design Study (WP-96-FS-BPA-07).

The firm loads expected at the current rates differ from the firm loads expected at the proposed rates. The expected firm loads at current rates for generating and non-generating publics and DSIs are lower than expected firm loads at proposed rates. As a result, expected short-term purchase power costs and revenues from Priority Firm and Industrial Firm power under current rates also are lower than under proposed rates. The amount of energy available for sale in the PNW short-term market under current rates, however, is higher than under proposed rates, resulting in an increase in economy energy market sales. The increase in energy available for sale in the short-term market is based on the difference between firm power sales expected in the initial proposal and firm power sales expected in the supplemental proposal minus power assumed to be remarketed by utilities, marketers, and brokers.

## 5.4 Revenue Forecast Methodology

The Revenue Forecast methodology begins by calculating the monthly surplus (deficit). Next, the sales and other uses of secondary energy are forecasted using the NFRAP model. Revenues from expected NF sales are calculated in NFRAP. The NFRAP model incorporates the results of the

Next, the billing determinants for power sales from the load forecasts are applied to the appropriate set of rates to calculate BPA's expected revenue. The calculation of revenue at current rates is included in section 3.7 of the WPRDS Documentation (WP-96-FS-BPA-05A). Finally, revenues from contract sales, miscellaneous products and services, transmission services, and unbundled power products are added to the power revenues.

5.4.1 Nonfirm Energy Revenue Analysis Program (NFRAP). The NFRAP is used to forecast sales and prices of nonfirm and surplus firm energy in the Pacific Northwest and the Pacific Southwest, the amount of nonfirm energy used to displace purchases, the amount of power expected to be purchased, the amount of power returned from off-system storage, the amount of money expected to be spent on the return of power from storage, and the amount of money expected to be spent on power purchases during the rate period. NFRAP documentation is found in section 2 of the WPRDS Documentation, WP-96-FS-BPA-05A.

The NFRAP compares various supply conditions with estimated demand conditions to estimate sales and revenues. Supply conditions are obtained from the Loads and Resources Study and the Federal Secondary Energy Analysis. Demand conditions are based on results from the Accelerated California Market Estimator (ACME), estimates of Pacific Northwest displaceable resources, and additional demand related to the net reductions in firm loads.

The NFRAP uses the ACME to estimate the market for economy energy in California over a range of prices. The ACME estimate of the California market has been revised to reflect a and PSW markets are documented in section 2 of the WPRDS Documentation, WP-96-FS-BPA-05A.

The NFRAP models the NF Standard and Market Expansion rates to increase nonfirm revenues in total to the Pacific Northwest as a region, rather than to the Federal system, within the constraints of applicable BPA rate schedules. The program applies the same marketing constraints to both Federal and non-Federal sales. Monthly revenues for each of the 50 historical water conditions are determined, then averaged. The 50-year average revenue is the expected monthly nonfirm revenues for the rate test period. This amount is increased by $11 million in the revenue forecast to account for additional savings expected from changes in operations during the rate period to reduce the costs of fish recovery programs. These operations could not yet be modeled at the time this forecast was prepared.

5.4.1.1 <u>Federal Secondary Energy Analysis (FSEA)</u>. The FSEA is used to estimate the amount of Federal and regional secondary (nonfirm) energy available to displace high-cost resources and for sale on the spot market. For purposes of the FSEA, nonfirm energy is synonymous with economy energy. The expected amount of economy energy is determined by subtracting residual Federal hydro loads from total Federal hydro generation for each of 50 historical water years. Using 1930 water conditions as a guide, a variable amount of purchases has been added so that deficits do not appear in the 1930 water condition. Similarly, these purchases have been assumed for all water conditions so that Federal resource deficits occur only in very unusual circumstances. Displacement of power purchases is the first use of economy energy when available. Residual

The 50 historical water years cover a broad spectrum of streamflow conditions from very dry to very wet. The average of these 50 streamflow conditions represents a "typical" water year. The FSEA estimates the amount of Federal secondary energy and provides it to the NFRAP, which calculates the uses of both nonfirm and excess firm energy, as well as revenues from the sale of these products in the short-term market. Excess firm and nonfirm revenues are a major component of BPA's excess revenues. The results of FSEA are shown in section 2 of the WPRDS Documentation (WP-96-FS-BPA-05A).

5.4.1.2 Fuel Price Forecast. A fuel price forecast is necessary to estimate the size of the market for spot market energy at various prices in the Pacific Northwest and the Pacific Southwest. Potential purchasers will make economic displacement decisions about their oil- or gas-fueled resources based on the relationship of fuel prices to the price of PNW spot market energy.

The fuel price forecast provides the expected prices of various fuels used for generating electricity in the Pacific Northwest and Pacific Southwest. The PNW forecast provides the expected price of natural gas and coal to electric generating utilities located in the Pacific Northwest. The PSW forecast provides the expected price of natural gas and coal to electric generating utilities located in the Pacific Southwest and the Inland Southwest. All PNW and PSW thermal resources with the capability to burn either oil or gas are assumed to use gas for economic reasons. Consequently, the forecasts for the price of oil to PNW and PSW electric generating utilities are not used in the revenue forecast at this time. The fuel price forecast is included in section V of the Marginal Cost Analysis Documentation (WP-96-FS-BPA-04A).

resource data received from the California Energy Commission since the final 1992 Energy Report. An overview of the methodology and the results of the ACME, as well as the California resources data base used by ACME, are contained in section 2 of the WPRDS documentation (WP-96-FS-BPA-05A).

5.4.2 Other Factors Affecting Forecasted Revenues. Several other factors may affect BPA's revenue forecast, because they affect revenues under current and/or proposed rates.

5.4.2.1 Availability Charge. The Availability Charge applies to customers who have a contractual right to displace their PF purchases from BPA with power from alternative suppliers or with power generated by their own resources that are not dedicated to meet their load. The Availability Charge applies to the amount that a customer is contractually entitled to purchase from BPA. For customers under the 1981 contracts, that amount is their Computed Energy Maximum. For customers under the 1996 contract, that amount is their Monthly Minimum HLH and LLH Contract Obligations. The determination of the Availability Charge parameters is documented in section 7.8 of the WPRDS documentation, WP-96-FS-BPA-05A. The Availability Charge is discussed in WPRDS section 4.2.

5.4.2.2 Low Density Discount. The application of the discount is shown in section 3 of the WPRDS Documentation (WP-96-FS-BPA-05A) for FY 1993, and in RAM Table RDS73 for the rate test period. Documentation for the Low Density Discount is in section 7.2 of the WPRDS Documentation.

BPA-05A). The Power Demand Reservation Charge is applied to Computed Requirements customers who do not choose to waive their right to schedule a portion of their Computed Maximum Requirement. For the purpose of this forecast, we have estimated that some utilities will waive a portion of their rights to take energy during heavy load hours. The estimate of waivers used here represents the minimum difference between a customer's Computed Maximum Requirement and the customer's billing demand during a recent 4-year period. Waivers are estimated to total about 3,000 MW-months per year. The Power Demand Reservation Charge is expected to be applied to about 3,300 MW-months each year. Waivers effectively reduce the amount expected to be received from this charge to about $1.6 million per year over the rate period. Documentation for revenues from the Power Demand Reservation Charge is contained in section 3.6 of the WPRDS Documentation, Revenue Forecast at Proposed Rates. Documentation for the Power Demand Reservation Charge is contained in section 7.8 of the WPRDS Documentation, WP-96-FS-BPA-05A.

## 5.5 FY 1996 Revenues

Revenues estimated under current rates during FY 1996 are shown in section 4 of the WPRDS Documentation (WP-96-FS-BPA-05A). Revenues in FY 1996, excluding revenues from the Residential Exchange program, are projected to be $2,479 million. Priority Firm revenues are projected to be $1,019 million. Revenues from DSI customers under the IP and VI rates are projected to be $515 million. Nonfirm and surplus firm power revenues, including sales at PPL-90, MSL-87, and MSC-86, are projected to be $472.3 million.

### 5.6 Revenues for FY 1997 through FY 2001

Revenues forecasted under current rates for the rate test period, FY 1997 through FY 2001, are shown in section 3 of the WPRDS Documentation (WP-96-FS-BPA-05A), as are revenues forecasted under proposed rates for the FY 1997 through FY 2001 rate test period.

5.6.1 Revenues for FY 1997 Through FY 2001 at Current Rates. Revenues estimated under current 1995 rates are shown in section 3.7 of the WPRDS Documentation (WP-96-FS-BPA-05A). The Priority Firm revenues for this period were estimated using the Low Density Discount (LDD) methodology BPA proposed in the 1996 rate proceeding rather than the methodology currently in place. This might make a small difference in projected revenues at current rates. Revenues at current rates (net of Residential Exchange) are projected to be $1,955 million in FY 1997, $1,928 million in FY 1998, $1,951 million in FY 1999, $1,929 million in FY 2000, and $2,020 million in FY 2001.

5.6.2 Revenues for FY 1997 Through FY 2001 at Proposed Rates. Revenues estimated under proposed rates are shown in section 3.6 of the WPRDS Documentation (WP-96-FS-BPA-05A). Revenues at proposed rates (net of Residential Exchange) are projected to be $2,272 million in FY 1997, $2,267 million in FY 1998, $2,314 million in FY 1999, $2,361 million in FY 2000, and $2,345 million in FY 2001.

## 6. RISK ANALYSIS

terms of deviations in net revenues (revenues minus costs) from the revenue and expense forecast used to set rates. The results of the Risk Analysis are used to support the amount of "Planned Net Revenues for Risk" that are included in the revenue requirement.

The Risk Analysis measures ordinary operational risks that BPA could reasonably expect to occur. The ordinary operational risks included in the Risk Analysis, which are referred to as risk factors, are designed to represent the types of risks that could affect BPA's net revenues. However, there are many risks that BPA could confront that are not measured by the Risk Analysis. For instance, the Risk Analysis does not include the economic impact of extraordinary risks on BPA, such as repayment reform or adverse litigation.

## 6.1 Methodology

The Short Term Risk Evaluation and Analysis Model (STREAM) was developed to quantify the net revenue risk BPA faces. It is a hydro regulation model that makes operational and economic decisions based on various reservoir, streamflow, load, resource performance, and nonfirm market conditions and estimates revenues and expenses under these various conditions. The STREAM estimates net revenues for a "Normal" case and numerous risk (called "Surprise") cases. The "Normal" case was developed based on the data used to calculate rates in the Rate Analysis Model. The "Surprise" cases were developed from data that deviated from the data used in the Rate Analysis Model. *See* WPRDS Appendix C for further details on STREAM.

values sampled from each probability distribution reflect their relative likelihood of occurrence. The output from these risk models was accumulated in a computer file to form a risk database. The risk values in this database are expressed in terms of proportions of the base numbers, and quantify risk in terms of values lower than, higher than, or equal to the "normal" values used in the base case revenue forecast. The STREAM makes operational and economic decisions based on the data in the risk database and estimates net revenues for each of the risk cases.

Net revenue risk was quantified by the STREAM by subtracting the net revenue estimated for the "Normal" case from the net revenues estimated for the "Surprise" cases. The differences in net revenues between the "Normal" case and "Surprise" cases reflect the net revenue risk BPA faces relative to the net revenue used for developing rates.

For discussion purposes, the various risk factors were grouped under the categories of PNW Resource Performance, PNW Loads, and PSW Nonfirm Energy Market.

## 6.2 Risk Factors

PNW Resource Performance. The *hydro production risk factor* reflects the uncertainty that the timing and quantity of streamflows have on monthly hydro production under current hydro operation requirements. This uncertainty was accounted for by estimating monthly hydro production based on monthly streamflow patterns experienced from August 1929 through July 1978. STREAM uses input and output data from the Hydroregulation Study in the Loads and

1996-FY 2001). *See* section 6.3, *infra*, for a discussion of the 300 six-year simulations. Each simulation uses a sequential set of 6 water years and starts each simulation using the water year one year after the start of the previous simulation. When the end of the 50 Water Years is reached (at the end of Water Year 1978), the reservoir level is reset to the level at the start of Water Year 1929, and a new cycle through the 50 Water Years begins by estimating monthly hydro production using Water Year 1929 data. STREAM runs through the 50 water years six times to achieve the 300 six-year simulations. This allows STREAM to estimate the impacts of persistent dry, normal, and wet weather patterns over time on the risks analyzed by STREAM and on BPA's net revenues.

For the 1996 final rate proposal, the first year during the 5-year rate period that the Hydroregulation Study was run in a continuous manner was FY 1998. (In the 1996 initial and supplemental rate proposals it was FY 1997.) (*See* Documentation for the Loads and Resources Study, Volume 2, WP-96-FS-BPA-01B, section 2.2.2). Accordingly, the hydro production risk in the STREAM was revised to be based on results from the Hydroregulation Study for FY 1998.

Higher streamflows usually increase revenues because more energy can be sold on the spot market, and decrease expenses because less power is purchased to meet load. Conversely, lower streamflows usually decrease revenues because less energy is available for spot market sales, and increase expenses because more power is purchased.

The *nuclear plant performance risk factor* reflects the uncertainty in the amount of energy and/or reduces expenses, because more energy is available for making spot market sales and/or displacing power purchases.  Lower than expected nuclear plant performance decreases revenues and/or increases expenses, because less energy is available for making spot market sales and/or displacing power purchases.

PNW Loads.  Priority Firm Power (PF) loads are affected by the *economic conditions risk factor*. This factor reflects the strength or weakness of the economy in the Pacific Northwest.  The level of economic activity, indicated by employment rates, can change expected loads placed on BPA by PF customers.

The *weather conditions risk factor* captures the effect that fluctuations in temperature have on the PF loads placed on BPA.  PF load fluctuations are most pronounced during the winter when heating loads are highest.

Because BPA's load/resource balance position is either deficit or has small surpluses in several months of the year, additional load will increase the amount of resources needed to serve the higher loads.  Higher than expected loads due to economic and weather conditions increase revenues and expenses.  Higher PF loads increase revenues, but the need to purchase energy to serve the higher loads increases power purchase expenses.  Lower than expected loads reduce BPA's revenues because of lower PF loads, and decrease power purchase expenses.  Lower loads increase the amount of available surplus energy.  The additional surplus energy either displaces power purchases or is sold on the spot market at rates determined by market conditions.

Administration for 1977-1985. Higher PSW streamflows reduce the need to run thermal plants in California and result in lower prices paid by California utilities for PNW nonfirm energy sales. Conversely, lower streamflows increase the need to run thermal plants in California and result in higher prices paid by California utilities for PNW nonfirm energy sales.

The *California loads risk factor* reflects the uncertainty in California loads due to fluctuations in temperature. Load fluctuations are most pronounced during the summer when cooling loads are highest. Variability in monthly California loads was derived from data used in various studies submitted to the California Public Utility Commission from 1985-1990. Higher loads increase the need to run thermal plants in California and increase prices at which PNW nonfirm energy is economic to California utilities. Conversely, lower loads decrease the need to run thermal plants in California and decrease prices that California utilities will pay for PNW nonfirm energy.

The *fuel price risk factor* reflects the uncertainty in surplus firm power and nonfirm open market revenues because of changing fossil fuel prices. Fuel price risk represents the level of fossil fuel prices used for electric generation, thereby affecting the prices BPA would realize for open market sales. Higher than expected fuel prices increase BPA’s revenues because of higher prices obtained in the spot market. Lower than expected fuel prices decrease BPA’s revenues because of lower prices obtained in the spot market.

### 6.3 STREAM Analysis

each of the "Surprise" cases, the initial reservoir level in the STREAM was set to 89.0 percent full and the STREAM was run from August 1995 through the end of FY 2001 in a continuous study mode.

Risk data were developed to accommodate the calculation of 300 net revenue cases for FYs 1996-2002. Output from the STREAM consisted of 300 net revenues for each of the fiscal years from FY 1996 through FY 2001. This yielded a total of 1,800 net revenues. The net revenues for FY 1997 through FY 2001 were used to calculate the probability of meeting the Treasury payment in each of those years. The net revenues for FY 1996, which are prior to the rate period, were not used when calculating the probability of meeting the Treasury payment during the rate period. They were used to incorporate into the Tool Kit Model the risk of BPA's cash reserve levels at the start of FY 1997.

6.4 STREAM Results

The results from the STREAM are an input into the last step of the Risk Analysis process, the Tool Kit Model. However, before the STREAM results are usable in the Tool Kit Model, an adjustment is necessary to reconcile the differences between the "Normal" case in the STREAM and the "base case" forecast made by the NFRAP.

The net revenue impact of various streamflow conditions is incorporated in the ratesetting process by calculating in the NFRAP the average net revenue earned when experiencing hydro conditions

"Normal" case using 1949 water conditions in the STREAM was a positive $12.0 million per year. That the average of the differences in net revenues earned between each of the 50 water years and the "Normal" case using 1949 water conditions in the STREAM was a positive value indicates that (1) the net revenues earned under 1949 water conditions are less than the average net revenues earned for the 50 Water Years, and (2) net revenues earned for the 50 Water Years need to be adjusted downward by an amount that offsets this difference. Accordingly, $12.0 million was subtracted from each of the net revenue results from the STREAM to correct for this positive difference. This adjustment in net revenues was performed in the Tool Kit Model.

The STREAM results show a negative bias in BPA's net revenues, reflected by the negative expected values. The reason for this negative bias is that mitigating factors tend to diminish the benefits of advantageous risk factor movements, while aggravating the costs of inopportune risk factor movements. For example, higher PF loads result in higher revenues for BPA, but because BPA faces energy deficits in several months of the year, BPA must incur the added cost of purchased power to serve the higher load. Most of the added purchases will be at prices higher than BPA would receive from the additional PF sale. Conversely, should PF loads decline, the excess energy in BPA's system can be marketed, but often at prices well below the PF rate.

This relationship tends to hold true for most of the risk variables. When taken together, these relationships result in an expected value of negative $8.2 million per year in BPA's net revenues for FY 1996 through FY 2001. After accounting for the negative $12.0 million adjustment

1996, negative $18.5 million in FY 1997, negative $19.7 million in FY 1998, negative $21.3 million in FY 1999, negative $19.3 million in FY 2000, and negative $20.2 million in FY 2001.

## 7. RATE SCHEDULE DESCRIPTIONS

The wholesale power and transmission rates developed in the WPRDS and TRDS are incorporated in the wholesale power and transmission rate schedules. The rate schedule document (WP-96-A-02, Appendix) includes three sections. The first section contains the wholesale power rate schedules. The second section contains the transmission rate schedules. Each rate schedule states to whom the rate schedule is available, rates for the products offered under the schedule, billing factors, and references to sections of the GRSPs that apply to that rate schedule. The wholesale power rate schedules include references to the applicable transmission rate schedules. The third section contains the General Rate Schedule Provisions for power and transmission rates. The GRSPs include adjustments, charges, and special rate provisions, and two lists of definitions, one of products and services and one of rate schedule terms.

### 7.1 Priority Firm Power Rate, PF-96

The PF-96 rate schedule replaces the PF-95 rate schedule. The PF-96 rate schedule is available for purchase of power by public bodies, cooperatives, Federal agencies, and utilities participating in the residential exchange under section 5(c) of the Northwest Power Act. Priority Firm power must be used to meet firm loads within the Pacific Northwest.

Priority Firm Power demand and energy, Full Load Shaping, Partial Load Shaping, and Load Regulation. At its discretion and subject to specified limitations, BPA also may make available the Flexible PF Rate Option, which includes rates and billing factors as mutually agreed to by BPA and the Purchaser. The PF rate schedule specifies which transmission rate schedule(s) may apply to purchases under the PF rate schedule. Customers may purchase under the PF-96 rate schedule for up to 5 years, pursuant to their power sales contract with BPA. The RPSA section of the PF-96 rate schedule shall apply for purchases by residential exchange customers until superseded. The PF-96 rate schedule includes a rate for Firm Capacity Without Energy for Computed Requirements customers purchasing under the 1981 Contract and an optional Composite Rate for power purchased by small Metered or Full Requirements customers (25 aMW or less).

Unlike the PF-95 rate, the PF-96 rate does not include diurnally differentiated demand charges. The PF-96 energy charges are seasonally differentiated, as in the PF-95 rate schedule, and also are diurnally differentiated based on the results of the Marginal Cost Analysis (WP-96-FS-BPA-04).

Purchases under the PF-96 rate schedule may be subject to provisions of the GRSPs, including among others the Low Density Discount, Deviation Adjustment, Unauthorized Increase Charge, Phase-In Mitigation, and Energy Return Surcharge. These are described in WPRDS section 4. Purchases under the PF-96 rate schedules also are subject to BPA's Billing Procedures.

7.2 New Resource Firm Power Rate, NR-96

schedule, the NR-96 rate schedule includes sections applicable to different types of purchasers under the 1981 Contract and the 1996 Contract.

Products available under the NR-96 rate schedule include New Resource Firm Power demand and energy, Full Load Shaping, Partial Load Shaping, and Load Regulation. At its discretion and subject to specified limitations, BPA also may make available the Flexible NR Rate Option, which includes rates and billing factors as mutually agreed to by BPA and the Purchaser. The NR rate schedule specifies which transmission rate schedule(s) may apply to purchases under the NR rate schedule. The NR-96 rate schedule also includes, for Computed Requirements customers purchasing under the 1981 Contract, a rate for Firm Capacity Without Energy. Changes since the NR-95 rate include an annual demand charge (no seasonal differentiation), and diurnally differentiated energy charges. Energy charges continue to be seasonally differentiated. Purchases under the NR-96 rate schedule may be subject to provisions of the GRSPs, as listed in the rate schedule, and are subject to BPA's Billing Procedures

### 7.3 Industrial Firm Power Rate, IP-96

The IP-96 rate schedule replaces the IP-95 rate schedule. The IP-96 rate schedule is available to BPA's DSI customers for firm power to be used in their industrial operations. Similar to the PF-96 rate schedule, the IP-96 rate schedule includes sections applicable to different types of purchasers under the 1981 Contract and the 1996 Contract.

Documentation section 7.10. The IP rate schedule also specifies which transmission rate schedule(s) may apply to purchases under the IP rate schedule. Changes since the IP-95 rate include an annual demand charge (no seasonal differentiation), and diurnally differentiated energy charges. Energy charges continue to be seasonally differentiated. Purchases under the IP-96 rate schedule may be subject to provisions of the GRSPs, as listed in the rate schedule. For the 1996 rate proposal, BPA is not including a First Quartile Discount in the IP-96 rate schedule. Purchases under the IP-96 rate schedule also are subject to BPA's Billing Procedures.

7.4 Industrial Power Spot Gas Rate, IPG-96

If a DSI customer is purchasing power under a 1996 Contract, this rate schedule is available only for power purchases above the amount specified in such contract. Only DSIs that purchase power under a 1996 Contract that specifies the spot gas rate option are eligible to purchase under this rate schedule. Purchases of power under the IPG-96 rate schedule must be for a 5-year term, October 1, 1996, to September 30, 2001.

Products available under the IPG-96 rate include Industrial Firm Power demand and energy. The spot gas rate is the sum of two components: a fixed charge and a variable charge derived by multiplying the Average Spot Market Gas Price by an energy multiplier. Both of these charges are expressed in mills per kilowatthour. The Average Spot Market Gas Price will be calculated monthly on a rolling twelve-month average basis and will be a simple average of the monthly spot gas price in each of the previous twelve months. The monthly spot gas price will be the price of the GRSPs, as listed in the rate schedule. Purchases under the IPG-96 rate schedule also are subject to BPA's Billing Procedures.

### 7.5 Variable Industrial Power Rate, VI-96

The VI-96 rate is available to BPA's DSI customers for firm power to be used in their aluminum and nickel smelting operations. This schedule is made available only for that portion of a DSI's load used in primary metal reduction including associated administrative facilities, if any. Only DSIs that purchase power under the 1996 Contract and that have signed a new Variable Industrial Rate Contract are eligible to purchase under the VI-96 rate schedule.

The variable rate formula will be based on the IP rate. The demand charge for the variable rate will be the same as the demand charge in the IP rate schedule, but the monthly energy charge can vary with the price of the metal used in the purchaser's smelting operation. An individual variable rate formula will be established at the time that BPA enters into a Variable Industrial Rate Contract with a customer. The formula will be designed so that BPA has the ability to hedge the aluminum or nickel price risk inherent in the rate formula, at zero cost to BPA, by entering into transactions with one or more substantial financial institutions.

Individual variable rate formulas may be established for any period from 1 to 5 years. At the expiration of the variable rate formula, a new one can be established, or the customer may purchase power under the IP rate schedule. However, the total term of all variable rate formulas

7.6 Nonfirm Energy Rate, NF-96

7.6.1 Rate Schedule. The NF-96 rate schedule is available for purchases of nonfirm energy both inside and outside the Pacific Northwest and outside the United States. The NF-96 rate schedule also may be used for transactions under the Western Systems Power Pool (WSPP) agreements. As with the NF-95 rate schedule, the NF-96 rate has four components: the Standard rate, the Market Expansion rate, the Incremental rate, and the Contract rate. In addition, the NF-96 rate schedule allows BPA and an end-user to agree to a rate or rate formula within the range delimited by the Standard and Market Expansion rates. The NF-96 rate schedule is different in several ways from the NF-95 rate schedule. For all nonfirm energy sales, transmission service over FCRTS facilities shall be subject to a separate transmission rate to the extent required. The calculation of the average cost of nonfirm energy has changed to exclude Network transmission costs. The Contract rate is equal to the average cost of nonfirm energy. The NF-96 rate schedule also clarifies the conditions when BPA may reduce guaranteed deliveries of nonfirm energy.

The Standard rate serves as BPA's general nonfirm energy marketing rate. BPA will make offers of nonfirm energy first at the Standard rate. Only one Standard rate offer will be made at any given time. The Standard rate is a flexible rate whose upper limit is 120 percent of the average cost of nonfirm energy. It allows BPA to offer prices above and below 22.25 mills per kilowatthour, the average cost of nonfirm energy (*see* below). The Standard rate is any rate offered equal to or below 26.70 mills per kilowatthour. Pricing flexibility is included in the Standard rate to allow the rate to be competitive in volatile markets.

This calculation includes Generation - Integration costs, which are the costs of transmission facilities that move power from Federal generation projects to the Network. Residential exchange program costs and loads are excluded from the calculation, as are WNP-3 Exchange loads. The average cost of nonfirm energy calculation has changed from the NF-95 calculation in that Network transmission costs have been excluded. Those costs will be recovered from separate transmission charges. The formula is:

$$\text{AVERAGE COST OF NONFIRM ENERGY} = \frac{\text{FBS} + \text{NR} + \text{OTHER} + \text{TRANS}}{\text{FIRMLD} + \text{NFLD} + \text{INT}}$$

where:

FBS = FBS resource costs ($000)

NR = New Resources costs ($000)

OTHER = Costs not directly identified with one specific resource pool ($000)

TRANS = That portion of the FCRTS generation/integration costs associated with firm power sales and services ($000)

FIRMLD = Total system firm sales excluding sales made pursuant to the residential exchange agreement and WNP-3 Settlement Agreement (GWh)

NFLD = Total forecasted sales, assuming an average of 50 water years, in the nonfirm energy market under the NF-96 rate schedule (GWh)

INT = Forecasted Interchange Sales (GWh)

Other costs include conservation costs, BPA program costs, short-term purchase power costs and Benefits ROD, WN-86-A-02.) The annual exchange-related cost arising from the WNP-3 settlement continues to be excluded from the determination of the average cost of nonfirm energy.

The Market Expansion rate may be offered concurrently with nonfirm energy offers at the Standard rate after BPA has determined that all markets at the Standard rate have been met. The Market Expansion rate is available to displace thermal resources, confirmed purchases of energy, or end-user alternate fuel sources. An end-user alternate fuel source is an energy source located at a consumer's facility and available to serve a consumer's load that is capable of being served with electricity in place of the alternate energy source. End-users may not use an alternative purchase of electricity to qualify for Market Expansion rate service.

Like the Standard rate, the Market Expansion rate is flexible. However, the Market Expansion rate is lower than the Standard rate to expand sales beyond those made at the Standard rate. BPA may have more than one Market Expansion rate in effect at any given time. To qualify for purchases under the Market Expansion rate, a purchaser must have a qualifying generation unit or power purchase with decremental cost that would not allow the unit to be economically displaced at the Standard rate being offered. A purchaser (1) with a qualifying resource or power purchase or (2) who has an alternative fuel source and is directly connected to BPA's system, can purchase under a Market Expansion rate when its decremental cost is less than the offered Standard rate plus 2.00 mills per kilowatthour. A unit with an alternative fuel source that is not directly connected to BPA's system may purchase under the Market Expansion rate when the decremental cost of the unit is less than the offered Standard rate plus 4.00 mills per kilowatthour.

purchaser not directly connected to BPA's system, the applicable Market Expansion rate is the highest rate offered below the purchaser's qualifying decremental cost by at least 4.00 mills per kilowatthour.

A guaranteed delivery option is available at BPA's discretion for NF-96 sales at the Standard and Market Expansion rates. Guaranteed nonfirm energy, when offered, will be offered in any amount or for any duration that BPA determines is prudent. The surcharge for guaranteed delivery is 2.00 mills per kilowatthour. The NF-96 rate clarifies the conditions under which BPA may reduce guaranteed deliveries: now included are situations when BPA must reduce nonfirm energy deliveries to serve firm load for any reason.

The NF-96 Incremental rate applies when energy may be available from discretionary resources or purchase power with incremental costs greater than the Standard rate less 2.00 mills per kilowatthour and a purchaser desires to purchase the energy produced from this resource or purchase. The Incremental rate is equal to the incremental cost of the power plus 2.00 mills per kilowatthour. No sales are forecast to be made at the Incremental rate.

The NF-96 Contract rate is 22.25 mills per kilowatthour, which is equal to the average cost of nonfirm energy. This calculation is changed from the NF-95 contract rate, which was based on average nonfirm revenues. The Contract rate is established for contracts that refer to the NF-96 rate schedule to determine the value of energy.

Nonfirm energy sales through the WSPP agreement will comply with the terms of the pool agreement and with regional and public preference.

7.6.2 NF Rate Cap. To provide a level of predictability for the California Energy Commission's (CEC) long-term planning, BPA established the NF Rate Cap in 1987. The NF Rate Cap applies to all sales of nonfirm energy under any applicable nonfirm rate schedule and expires September 30, 1999.

The methodology of the NF Rate Cap is unchanged. The NF Rate Cap is defined by a formula based on BASC and PSW utilities' decremental fuel cost, and will follow changes in either of these two costs. The NF Rate Cap formula is the greater of BASC or BASC plus 30 percent of the difference between PSW utilities' decremental fuel cost and BASC.

BASC is determined by dividing BPA's forecasted revenue requirement for the test period by BPA's expected total sales for the same period. BASC is 27.11 mills per kilowatthour for the rate period. The BASC component of the rate cap formula is recalculated in each BPA general rate case. BASC is calculated simultaneously with the determination of BPA's other wholesale power rates and remains constant throughout the effective period of the rates.

7.7 Reserve Power Rate, RP-96

The RP-96 rate schedule replaces the RP-95 rate schedule. The RP rate is available in cases demand charge (no seasonal differentiation), and diurnally and seasonally differentiated energy charges. The demand charge is set equal to the demand charge in the PF, IP, and NR rate schedules. The energy rates are based on the marginal costs of firm energy in the MCA. The marginal costs are levelized over the 5-year rate period and converted to nominal dollars. *See* section 7.11 of the WPRDS Documentation, WP-96-FS-BPA-05A. BPA's Load Regulation and Load Shaping charges are added to the levelized nominal marginal costs of energy to produce the published RP energy rates. Applicable GRSPs are listed in the rate schedule.

### 7.8 Power Shortage Rate, PS-96

The PS-96 rate schedule is available for sales under the Share-the-Shortage agreement or a similar substitute agreement. BPA is not obligated to make Shortage Power available or broker power under the PS-96 rate schedule unless specified by contract. The PS-96 rate schedule includes a power rate, not to exceed 100 mills per kilowatthour, which may be specified by contract as an energy charge only, or as both demand and energy charges. It also includes a brokering rate, up to 1.00 mill per kilowatthour, for services provided when BPA arranges for energy purchases for a customer from a seller other than BPA. Applicable GRSPs are listed in the rate schedule.

### 7.9 Firm Power Products and Services Rate, FPS-96

The FPS-96 rate schedule is available for purchase of Firm Power, Supplemental Control Area Services, Shaping Services, and Reservation and Rights to Change Services inside and outside the

The FPS-96 rate is available for the purchase of Firm Power (energy, capacity, or energy and capacity). Similar to the SP-93 rate, the FPS-96 rate contains a Contract rate and a Flexible rate. The design of the FPS-96 Contract rate differs from the SP-93 Contract rate, however. The energy charges are seasonally and diurnally differentiated based on the results of the Marginal Cost Analysis (WP-96-FS-BPA-04). The Contract rate demand charge is the same as that in the PF-96, NR-96, and IP-96 rate schedules. The Flexible rate, similar to the SP-93 rate, is a market-based rate that is flexible upward and downward, as mutually agreed by the contracting parties. The Flexible rate may have a demand component, an energy component, or both. The Flexible rate, unlike the SP-93 rate, is not limited to the costs of BPA's highest-cost resource. Applicable transmission and Intertie rates will apply, to the extent required, to purchases of firm power under the FPS-96 rate.

The FPS-96 rate differs from the SP-93 rate in that firm power available under the FPS-96 rate may be supported by power purchases. Unbundled products also are available under the FPS-96 rate schedule that were not available under the SP-93 rate schedule.

Supplemental Control Area Services, Shaping Services, and Reservation and Rights to Change Services are available at flexible rates as mutually agreed by the contracting parties.

Forecasted revenues for the 5-year rate period from firm power sales under the FPS-96 rate are discussed in WPRDS section 5.2.3 and are shown in section 5 of the WPRDS Documentation, WP-96-FS-BPA-05A. The revenue forecast for FPS firm power and unbundled products for the

7.10 Ancillary Products and Services Rate, APS-96

The Ancillary Products and Services (APS-96) rate schedule is available for the purchase of ancillary products and services necessary to support the purchaser's transmission use of the Federal Columbia River Transmission System (FCRTS). The services are consistent with the ancillary services requirements of FERC Order 888. Ancillary products and services may be purchased under any new agreements that provide for the delivery of power between resources and loads using the FCRTS, and under current agreements where the contract provides for charges for such service. Ancillary products and services available under the APS-96 rate schedule are Energy Imbalance, Control Area Reserves for Resources; Control Area Reserves for Interruptible Purchases; Load Regulation; and Transmission Losses.

Forecast revenues from ancillary services provided under the APS-96 rate schedule are discussed in WPRDS section 5.2.3.

**Appendix A**

**7(c)(2) Industrial Margin Study**

## Introduction

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to direct service industrial (DSI) customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region."

Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account

> (A) the comparative size and character of the loads served,
> (B) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and
> (C) direct and indirect overhead costs,

all as related to the delivery of power to industrial customers.

## Purpose

The purpose of this study is to describe the calculation of the "typical margin" included by the

**Methodology**

**Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers**. BPA applies the PF-96 demand and energy charges and the Point-to-Point transmission charge (before any 7(b)(2) or floor rate adjustments) to the forecasted DSI billing determinants.

**Typical Margin**. The "typical margin" includes "other overhead costs" charged by the utilities in the study. Production and transmission costs are accounted for in the PF rate charges, and distribution costs are accounted for by adding in a charge for BPA's DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

**Margin Determination Factors**

**7(c)(2)(A)–Comparative Size and Character of the Loads Served**. The data base used for the study includes utilities that serve at least one industrial customer with a peak demand of at least 3.5 megawatts.

**7(c)(2)(B)–Relative Costs of Electric Capacity, Energy, Transmission and Related Delivery Facilities Provided and Other Service Provisions**. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate allocated costs to the industrial customer class. The utilities segregate these costs into various cost categories

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for the lower quality of service to the first quartile.  BPA has not made this adjustment as part of this study.

**7(c)(2)(C)–Direct and Indirect Overhead Costs**.  BPA relies on cost of service studies and other spreadsheets prepared by the public body and cooperative customers to incorporate the per unit overhead costs associated with service to large industrial customers.

**Application of the Methodology**

The derivation of the margin involves two steps.  First, an individual margin is determined for each utility in the study.  Second, each margin is weighted according to energy sales to derive an overall margin.  BPA's DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

**Data Base**.  The data base consists of cost information from twenty utilities that serve a total of 72 industrial customers with peak demands of at least 3.5 megawatts.  Attachment A contains a summary of the data provided by each utility, the energy-weighted margin components, and the overall energy-weighted margin.

**Utility Margins**.  The individual utility margins are based on categorical costs allocated by the utilities to their industrial customers.  The categories of costs include production, transmission, distribution, revenue taxes, and other overhead costs.  The data for each of the utilities in the study are included as Attachment B.  The total dollar amounts assigned by the utility to each category, divided by the total kilowatthour energy sales to the industrial class

**Summary of Results**

The results of each step in the margin calculation are shown in Attachment A. The weighted industrial margin is 0.44 mills per kilowatthour. This margin has been added to the PF-96 energy charges and applied to the forecasted DSI billing determinants.

**Appendix B**
**Value of Reserves Study**

## Introduction

Section 7(c)(3) of the Northwest Power Act provides that the Administrator shall adjust rates to the direct service industrial (DSI) customers "to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." The DSIs provide two types of reserves: forced outage reserves and stability reserves. The purpose of this study is to calculate the value of these reserves to determine the credit to be applied to DSI rates.

**Forced Outage Reserves**. Forced outage reserves are the generating capacity BPA plans to have available to serve peak loads during forced outages. A forced outage exists when a generating or transmission facility unexpectedly fails to perform or is shut down for emergency reasons.

BPA's restriction rights allow the agency to curtail deliveries to the DSIs and use the energy to supply other firm loads when there is not enough generation to meet all firm loads. The restriction rights eliminate the need for BPA to acquire additional generation resources as a contingency for unexpected high loads or other short-term power system emergencies, when BPA might be unable to meet its firm power obligations to other customers.

Under the Northwest Power Pool Operating Reserve Sharing Program, BPA maintains reserves equal to 5 percent of on-line hydroelectric generation and 7 percent of on-line thermal generation. Half of this amount is non-spinning reserve. BPA's non-spinning reserve obligation is 500 megawatts (MW). In addition, BPA must carry non-spinning reserves equal to its on-demand obligations. These range from 750 MW to 1750 MW. Thus, BPA's reserve need is between 1,250 and 2,250 MW.

For purposes of this study, BPA assumes that the cost of the least-cost alternative for providing reserves represents the value of the DSI reserves to BPA. In the 1982 rate case, BPA concluded that combined cycle combustion turbines (CTs) were the least-cost alternative, and that BPA would have installed CTs if the DSI restriction rights had not been available. For this rate case, BPA is again assuming that the least-cost alternative is the CTs built in 1982. In the 1982 rate case, BPA assumed that it had installed 1880 MW capital cost of the CTs was $770 million and was amortized over their assumed 25-year projected life. This resulted in an annual investment cost of approximately $112 million.

For this rate case, BPA assumes that the CTs were refinanced in 1993 at an interest rate of 6.95 percent. BPA applied a 1.5 percent finance charge to the refinancing and amortized this charge over the remaining life of the CT. The refinancing or bond issuance charge consists of printing costs of the official statements and bond resolutions, fees to rating agencies, the cost of bond counsel, fees for financial advisors, and other overhead costs. After the refinancing, the annual investment cost of the CTs is $77.809 million. The derivation of this figure is shown on Attachment A.

BPA based the O&M costs on Beaver thermal plant data, escalated to 1997 dollars. The data, which show O&M costs in 1986 dollars, are from the Pacific Northwest Utilities Conference Committee Thermal Resource Data Base. The escalation factors are contained in the documentation for the 7(b)(2) Rate Test Study, WP-96-FS-BPA-07A. The calculation of the O&M costs is shown on Attachment B. The fixed O&M costs are $12.22 million annually.

The total average forecasted DSI load for the rate period is 1842 MW. Under either the 1981 or the 1996 contract, half of this figure is available for forced outage reserves. Therefore, the DSIs provide 921 MW of reserves.

BPA added the annual investment cost of $77.809 million and the annual fixed O&M costs of $12.22 million to derive a total annual cost of $90.029 million. This cost, however, is based on reserves of 1880 MW. Because the DSIs are providing only 921 MW of reserves, they were credited with 921/1880 of the annual cost, or $44.105 million.

**Stability Reserves**. Stability reserves are loads that are available to be instantaneously disconnected from the electrical power system for specific system disturbances. A system disturbance is an event that results in the unplanned outage of transmission facilities. For purposes of this study, there are two types of stability reserves: regional stability reserves and local stability reserves. The regional stability reserves, which all DSIs are required to provide and for which all receive compensation, protect against outages of the Pacific Northwest/Southwest DC Intertie (Southern Intertie) when it is being used to import power into the Pacific Northwest. The local stability reserves are those provided by the Intalco Aluminum Corporation in the Bellingham area. These reserves protect BPA's ability to export power to Canada over the BPA-British Columbia Hydro and Power under-frequency load shedding program (UFLS) protects the power system through load tripping at certain predetermined sites in the unlikely event of a catastrophic disturbance that is beyond the scope of the BPA and Western Systems Coordinating Council (WSCC) planning criteria.

The least-cost alternative was assumed to be a load tripping scheme installed at non-DSI load sites. BPA assumed that the existing high-speed load tripping scheme would be extended to most of the existing UFLS sites. In addition, BPA assumed that load tripping would be added at other sites where it would be most cost-effective, to attain a total of 1,800 MW of load tripping. The alternative sites are shown on Attachment C.

**Valuation of Regional Stability Reserves**

Control System. The ICLTS includes a controls system and a communications system. The controls system includes two computer-based central controllers that determine what actions need to be taken based on certain power system conditions, such as the loss of an intertie. The scheme assumes that one central controller would be installed at BPA's Dittmer Control Center and the other at BPA's Munro Control Center. When the central controllers have determined an action to take, such as tripping a particular load, this information is transmitted through special control equipment at the control centers to the particular load site, which contains control equipment to receive this information. Additional control equipment at the particular load site translates the information received and automatically operates other equipment at the load site to disconnect the load from the power system.

The communications system is composed of all the equipment that is necessary to establish a dedicated path between each central controller and each load site. The central controllers transmit information to the load sites via BPA's microwave system. A microwave communication path must exist between every load site and the central controllers at the control centers. This path allows the fast response of the control equipment at the load sites when a command is issued by the central controllers. The communications system is critical in implementing the ICLTS because of the long distances that separate the central controllers and the load sites, and because of the necessity for the high-speed operation of the scheme with high dependability.

The costs of the control equipment are as follows:

1. The cost of the equipment and labor involved at a load tripping site at a BPA substation: $60,000.

other 35 sites are non-BPA sites. At $89,000 per site, this equals $3.115 million. The total cost for all sites is $4.555 million. Two control centers at $1,370,000 per center equals $2,740,000. Therefore, the total cost of the control equipment is $7.295 million. The derivation of the costs is shown on Attachment D.

All of the equipment and labor noted above in regard to a BPA site also would be needed for a non-BPA utility site. The additional costs for a non-BPA site include the increased labor involved in negotiating contracts with the utility for installation of equipment at its substation, and the cost of installing equipment at the substation for connection to the new control equipment.

Communications. Estimates for 23 of the sites are based on channel costs. These sites are existing Bonneville substations with existing microwave radio terminals. The most cost-effective way to provide the needed communications circuits to these sites is to use Bonneville's existing telecommunications system, which primarily uses analog microwave radios. Adding electronics equipment, called multiplex, would allow the use of the available microwave system capacity for the two circuits that are needed for each substation: one circuit goes to Dittmer Control Center and the other goes to Munro Control Center. The cost estimates for these 23 substations are based on typical multiplex (channel) addition costs on the system. The totals vary depending on the number of microwave systems that the circuits traverse between the control centers and the substations.

The typical cost of adding multiplex at a radio terminal is $2,100. Thus, the cost for one circuit over one system would be twice this amount, or $4,200, because a multiplex would be required at both the substation and the control center. To travel between a substation and the appropriate control center, a signal must traverse anywhere from one to four or more microwave systems. Each microwave system for each circuit costs $4,200. Attachment C shows the summation of these costs for the two circuits to each substation.

The radio terminal at Ross is not located at the substation. Therefore, the multiplex at the radio terminal must be connected to two pairs of wires in an existing cable to the substation to "extend" or send the signal to the substation where the wires connect to the load trip equipment. At the McNary substation, part of the channel costs are for digital multiplex equipment to transmit the tripping signal into an existing fiber optic (lightwave) terminal. McNary is the only location where the load tripping scheme encounters a fiber optic system.

path distances vary from a few miles up to 30 miles or more.  The microwave transmitters and receivers are located at each end of the path, and are referred to as radio terminals.

The typical cost of a radio terminal addition at an existing radio site is $140,000.  The typical cost of a radio terminal addition at a substation site is $211,000, for a total cost of $351,000.  Attachment C shows the costs included for each site.  For example, the first site is the Weyerhaeuser plant, with costs of $359,400.  This figure includes $351,000 for the two radio terminals and $8,400 for two microwave circuits at $4,200 each.

The path between the Scott Paper substation and the existing radio repeater site is obstructed by hills and trees.  In order for the microwave signal to clear these obstructions, a very tall tower would be required.  Because a tower of such magnitude would not be practical, use of a passive is assumed instead.  A passive is a billboard-like structure that redirects or bounces the microwave signal in cases where the direct microwave path is obstructed.  It consists of a very flat reflecting surface mounted on a short microwave tower on an undeveloped site, situated in the line of sight of both ends of the microwave path.  The cost of the passive for the Scott Paper site is $60,000.

The initial proposal included DSI sites in the stability reserves scheme.  These sites were eliminated in the supplemental proposal in favor of an additional 34 non-DSI sites.  At those sites that required microwave extensions, costs were based on the average costs of installing this equipment at sites contained in the initial proposal.  This average is $368,215.

The cost of the controls system, or $7.295 million, was added to the cost of the communications system, or $13.634 million.  Overhead equal to 50 percent of the total cost was added to this figure.  This resulted in a project cost of $31.394 million.

The total capital cost of the load tripping system was then converted to an annual cost. The ten-year amortization is based on the expected useful life of a specialized stability load tripping scheme such as this.  The annual capital cost of the system is $4.569 million.  An annual maintenance cost equal to 2.47 percent of the annual capital cost was added to the total.  Thus, the total annual cost for the capital facilities is $5.344 million.

In addition, the study included the costs of compensation for the loads included in the alternative load tripping system.  Compensation was based on a study done by the Electric Power Research Institute (EPRI).  The compensation is the amount consumers would

Therefore, the total annual cost of the regional stability reserves system is $5.989 million. Calculation of the value of reserves credit applied to all DSIs is shown on Attachment E.

**Valuation of Local Stability Reserves**. The Bellingham area stability reserves protect against an outage of both Custer-Monroe transmission lines when moderate to high levels of power are flowing south to north on the Northern Intertie. These reserves are needed to meet WSCC Criteria, which require that an intertie be rated at a level at which it can be demonstrated that other WSCC member systems will not be adversely affected by an outage on the host system. The present south-to-north rating requires Intalco load tripping to prevent unacceptable impacts to other WSCC member systems.

BPA based the valuation on the cost of the least-cost alternative to the Intalco load tripping. This alternative was assumed to be the construction of a third Custer-Monroe 500 kV transmission line. The line would be 87 miles long and would require four circuit breakers and annual maintenance on two line terminals. The cost for this line is based on cost information found in the 1993 BPA Transmission Line Estimating Data and in the Annual Financial Requirements for Bonneville Power Administration Transmission System (Annual Cost Ratios) and revised Operation and Maintenance (O&M) tables, dated June 2, 1995.

The capital cost of the transmission line is $658,350/mile (1993 dollars). The capital cost of four power circuit breakers is $6,000,000 (1993 dollars). An Environmental Impact Study (EIS) costs $750,000 (1993 dollars). Overhead equal to 50 percent of the capital cost of the transmission line and the power circuit breakers was added. The costs were converted to an annual cost by using the appropriate capital recovery factors (0.0778 for the transmission line and EIS and 0.08037 for the circuit breakers). Thus, the annual project capital cost is $8,665,602.

The O&M cost for the transmission line is $2,598/mile/year (1995 dollars). The O&M cost for two line terminals is $65,376/year (1995 dollars). To determine the annual project O&M cost, the costs were escalated to 1999, the middle of the rate period, by using an escalation factor of 1.1140. Thus, the annual O&M cost is $324,622. The total annual project cost of a third Custer-Monroe 500 kV transmission line is $8.990 million.

The construction of a third Custer-Monroe line would produce other significant benefits to BPA in addition to mitigating the need for Intalco load tripping. These benefits include

# APPENDIX C

Technical Appendix
for the Short-Term Risk Evaluation and Analysis Model
(STREAM)

## Introduction

As indicated in the testimony of Arnold *et al.*, WP-96-E-BPA-15, the purpose of this technical appendix is to describe changes to the Short-Term Risk Evaluation and Analysis Model (STREAM), as it relates to BPA's Risk Analysis. This technical appendix also provides information on changes since the 1993 rate case to the pre-STREAM risk models that produce the risk data read by the STREAM. Additional information regarding the STREAM and pre-STREAM risk models are contained in WPRDS section 6 and WPRDS Documentation section 6 (WP-96-FS-BPA-05A).

This discussion of the STREAM does not, nor is it intended to, provide a comprehensive discussion of all issues concerning the STREAM and the pre-STREAM risk models. Several issues concerning the STREAM and the pre-STREAM risk models were presented in the 1993 rate case. See Bliven, *et al.*, WP-93-E-BPA-11.

## The Basis for Changes to the STREAM and the Pre-STREAM Risk Models

The purpose for the revisions made to the STREAM and the pre-STREAM risk models is to improve the calibration of the STREAM results relative to other models and analyses used in the ratesetting process. Testimony filed during the 1993 rate case pointed out that the pre-STREAM risk models and the STREAM developed and used to perform the Risk Analysis in the 1993 rate case substantially improved the Risk Analysis relative to the method used in the 1991 rate case. One weakness cited with this new methodology, however, was that there was some loss in accuracy in forecasting revenues and power purchase expenses. *See* Bliven, *et al.*, WP-93-E-BPA-11, at 5. This loss in accuracy in forecasting revenues and power purchase expenses was primarily due to inaccuracies in estimating hydro production and operations and the resulting secondary energy sales and power purchases in the STREAM. Since the 1993 rate case, however, there has been an ongoing effort to improve the hydro operations, hydro production, and the estimates of

## The Pre-STREAM Risk Models

The pre-STREAM risk models quantify the variations from base case values used to determine BPA's rates. Four important areas of risk, or risk factors, have been identified. The four areas consist of the following: (1) hydro generation from varying streamflows; (2) nuclear generation; (3) the impact of economic and weather conditions on Public Utility loads; and (4) the impact of PSW hydro generation, weather conditions, and fossil fuel prices on the California market for PNW nonfirm energy sales. These risks are quantified in pre-STREAM risk models, which sample values from probability distributions and develop sets of proportions that are applied by the STREAM to base case values.

## Hydro Generation Uncertainty

Since the 1993 rate case, the method used to incorporate monthly hydro risk into the STREAM analysis has been revised, so that 1929 water conditions would begin following the end of the 1978 Water Year. Under this revised method, 3000 thousand second foot days (ksfd) (approximately 9000 MW-mo.) are added to the reservoir levels after Water Year 1978 ends and before 1929 water conditions begin to restore reservoir levels to where they started in 1929. In contrast, the method used in the 1993 Rate Case extended streamflow conditions to water years subsequent to Water Year 1978, rather than wrapping to use 1929 water conditions after 1978 water conditions. For example, under the 1993 method, a risk analysis for three years would use Water Years 1978 through 1980 (rather than Water Years 1978, 1929, and 1930), and 1929 water conditions would be used only in the first year of an analysis.

Several reasons prompted BPA to make this change. The Hydroregulation Study performs analyses only for Water Years 1929-78. Accordingly, there are no data available for operational rule curves, water-to-energy conversion factors, spillage, ratios of Federal to non-Federal generation, and Federal and non-Federal hydro independent generation numbers from the Hydroregulation Study beyond 1978. Additionally, the new method, in contrast to the old method, yields an equal number of observations for all water years. The reason for this is that the water years in the early years are now sampled the same number of times as all other water years. Moreover, the problem of unequal sampling increases as the number of years that the Risk Analysis is performed increases. The number of years that the Risk Analysis is performed has increased from two years to six years.

the average of the differences in net revenues earned between each of the 50 Water Years and net revenues earned under average monthly streamflow conditions being equal to a negative $63.5 million. That the average of the differences in net revenues earned between each of the 50 water years and the "Normal" case using average monthly streamflows for the 50 Water Years in the STREAM was a negative value indicates that (1) the net revenues earned using average monthly streamflows for the 50 Water Years are more than the average net revenues earned for the 50 Water Years and (2) net revenues earned for the 50 Water Years need to be adjusted upward by an amount that offsets this difference. Accordingly, $63.5 million was added to each of the net revenue results from the STREAM to correct for this positive difference. This adjustment in net revenues was performed in the Tool Kit Model.

In the 1996 rate case, the hydro risk for the "Surprise" cases is estimated in the same manner, but the "Normal" case was developed using 1949 water conditions and hydro operations. The basis for this change is that the "Normal" case, like the "Surprise" cases, needs operational rule curves, water-to-energy conversion factors, spillage data, ratios of Federal to non-Federal generation, and data of Federal and non-Federal hydro independent generation for estimating net revenues. The Hydroregulation Study does not contain this information for using average monthly streamflows, and therefore, one of the 50 Water Years must be selected to represent hydro conditions for the "Normal" case.

Water conditions and hydro operations for 1949 were selected for the "Normal" case in the STREAM because the net revenues for that water year were similar to the average net revenues for the 50 Water Years. After assessing revenue minus purchase power expense values for each of the 50 Water Years in output from a Revenue Forecast Model run, 1949 water conditions and hydro operations yielded net revenues comparable to the average net revenues for the 50 Water Years. The selection of 1949 data to represent hydro conditions and operations for the "Normal" case was later solidified based on the fact that the annual hydro generation for Water Year 1949 in the Hydroregulation Study represented median hydro generation. Finally, the STREAM was modified to perform a 50 Water Year Run, with 1949 water conditions and hydro operations representing the "Normal" case. The modification was performed to test the appropriateness of Water Year 1949 and determine the amount of adjustment in the Tool Kit Model needed by each of the net revenue results from the STREAM. The results from the 50 Water Year Run indicate that net revenues earned under 1949 streamflow conditions closely approximated the average net revenues earned for the 50 Water Years. The average of the differences in net revenues earned between each of the 50 water years and the "Normal" case using 1949

Improving the accuracy of estimates of hydro generation

Four changes were made to improve the accuracy of estimates of hydro generation uncertainty. Improvements in hydro operations were realized by the incorporation of additional rule curves. This is discussed in more detail below. Of the remaining changes, the first involved calculation of monthly water-to-energy conversion factors for hydro generation for each of the 50 Water Years from input and output data from HydroSim. These water-to-energy conversion factors were calculated after accounting for forced spill reported in output from HydroSim. These data, as well as additional data to be discussed later, were stored in the risk data files read by the STREAM, and the computer code in the STREAM was modified to utilize these data in its logic and calculations. Next, monthly proportions of the hydro production that the Federal and non-Federal System received from the Coordinated Hydroelectric System for each of the 50 Water Years were calculated from HydroSim output and incorporated into the STREAM. Finally, monthly output of the BPA and non-Fed hydro independents for each of the 50 Water Years, which was not incorporated in the 1993 rate case, were calculated from HydroSim output and incorporated into the STREAM.

Inclusion of the monthly water-to-energy conversion factors for hydro generation for each of the 50 Water Years

Inclusion of the monthly water-to-energy conversion factors for hydro generation for each of the 50 Water Years substantially improves the accuracy in the estimates of hydro generation. In the 1993 rate case, water-to-energy conversion factors were calculated for each month of the 50 Water Years by dividing hydro generation in average megawatts (aMW) for the PNW Coordinated Hydroelectric System by the outflows in thousand cubic feet per second (kcfs) at The Dalles. The water-to-energy conversion factors for all 50 Water Years were averaged for each month to yield average monthly water-to-energy conversion factors. These average monthly water-to-energy conversion factors were multiplied by average monthly streamflows to yield average monthly energy values for streamflows for the “Normal” case. Monthly energy values for streamflows for the 50 Water Years (“Surprise” cases) were developed by multiplying ratios of streamflows to average streamflows times the average monthly energy values for streamflows for the “Normal” case. This resulted in streamflow variability being accounted for in the monthly calculations of energy, but the monthly water-to-energy conversion factor being held constant. This method yielded inaccurate estimates of energy production, because water-to-energy conversion factors vary considerably according to the level of the reservoirs, the

the corresponding streamflows.  These water-to-energy conversion factors for each of the 50 water years are calculated in a manner similar to that used in the 1993 rate case, except that the impact of spill is accounted for in the calculations of the water-to-energy conversion factors.

<u>Inclusion of monthly proportions of hydro production received by the Federal and Non-Federal system from the Coordinated Hydroelectric System</u>

Inclusion of monthly proportions of the hydro production that the Federal and non-Federal System receive from the Coordinated Hydroelectric System for each of the 50 Water Years substantially improves the accuracy of the delineation between Federal and non-Federal hydro generation.  In the 1993 rate case, monthly proportions of the hydro production that the Federal and non-Federal System received from the Coordinated Hydroelectric System were calculated for each month of the 50 Water Years by dividing Federal hydro generation (in aMW) by hydro generation for the PNW Coordinated Hydroelectric System (in aMW).  The ratios for all 50 Water Years were averaged for each month to yield average monthly ratios.  These average monthly ratios were used to estimate the Federal and non-Federal  proportions of total hydro generation for all 50 Water Years.  Under the new method, the monthly proportion of hydro generation that BPA receives is substantially improved, because it varies for each of the 50 Water Years.

<u>Inclusion of monthly output of the BPA and non-Federal hydro independents</u>

In the 1993 rate case there was no variability in the monthly output of the BPA and non-Federal hydro independents.  Water Year 1930 hydro independent energy production was subtracted from BPA and NW Utility loads to yield residual hydro loads.  Under the new method for the 1996 rate case, the impact of hydro independents is substantially improved. Water Year 1930 hydro independent energy production is not subtracted from BPA and NW Utility loads for all 50 Water Years, but instead, monthly hydro independent output for each water year is subtracted from all loads.  Also, this new method removes a bias in the level of production from hydro independents, because Water Year 1930 hydro independent output represents critical period rather than average hydro independent output.

**<u>Nuclear Generation Uncertainty</u>**

There has been no change in the method used to estimate the uncertainty of nuclear same as that used in the 1993 rate case. Although it was possible to include other components of uncertainty, such as uncertainty in the estimated parameters and the equation error term, this was not included. Given the almost perfect fit of the medium case forecasting models' equations, it was unclear that pursuing a more complete risk model would result in a significant improvement.

**California Market Uncertainty**

Although no changes have been made in the method used to estimate California Market Uncertainty since the 1993 rate case, a California Market Uncertainty model has been made for each of the Fiscal Years in the rate period. Each of these risk models contains the same logic and data, except that California load data were revised in each model to reflect the load forecast reported in the California Energy Commission's (CEC's) 1994 Electricity Report (ER-94).

**Fuel Price Uncertainty in the California Market**

The model structure of BPA's uncertainty analysis pertaining to the forecast of fuel price uncertainty in the California market has been revised since the 1993 rate case, in that a long-term trend risk component has been added to the weighted average gas price. The basis of the long-term trend is the monthly long-term gas price forecast. The new logic replaces the term that was the average of the gas prices over the historical period. This change for 1996 significantly improves BPA's ability to capture the seasonal cycles in gas prices and the uncertainty in long-term trend.

**Revisions to the STREAM**

As indicated in the testimony of Arnold, *et al.*, WP-96-E-BPA-15, the purpose of the STREAM is to act as a hydroregulation model that makes operational and economical decisions based on reservoir, streamflow, load, nuclear performance, and spot market conditions. As these conditions vary simultaneously, the STREAM estimates BPA's net revenues on a fiscal year basis. Since the 1993 rate case, the STREAM has been revised to perform its hydro and storage operations on the basis of ksfd rather than energy. There are several reasons for this change. Actual hydro operations are governed by the current and projected reservoir levels specified in ksfd compared to operational rule curves specified in ksfd. If one were to try to develop rule curves to guide hydro operations throughout the year, one would have to inappropriately assume monthly water-to-energy hydro operations in the STREAM. Finally, specifying hydro operations in terms of ksfd instead of energy allows improvements in storage and hydro generation estimates. This revision allows excess inflows (inflows greater than generation requirements) to be stored in ksfd and later generated at the water-to-energy conversion factors when it is released, rather than being stored at the water-to-energy conversion factor for generation at the time it was stored.

Now that hydro operations are based on ksfd, rather than energy, the amount of energy in storage is calculated through the use of monthly water-to-energy conversion factors for hydro storage for each of the 50 Water Years. These water-to-energy conversion factors were calculated from reservoir levels specified in terms of ksfd and MW-mo. reported in output from HydroSim. These monthly ksfd values were converted into kcfs equivalents and multiplied by the water-to-energy conversion factors for hydro storage to calculate the amount of MW-mo. of energy in storage for each month. Notably, however, these calculations have no impact on the net revenue results from the STREAM, but are calculated for informational purposes only.

In the 1993 rate case, hydro operations in all 50 Water Years were required to meet the same minimum flow requirements, specified in energy. In actual hydro operations, however, streamflow levels and hydro operation constraints will not allow this requirement to be met in all 50 Water Years. Moreover, water-to-energy conversion factors vary depending on streamflows and reservoir levels. Accordingly, the minimum flow logic in the STREAM was removed for the 1996 case because reservoir level output from HydroSim reflects the ability and inability to meet these flow requirements during each of the 50 Water Years.

Use of reservoir levels and forced operational spill data from HydroSim output has substantially improved the estimates of power purchases, secondary energy sales, and forced operational spill (spill that is not due to market saturation or intertie constraints). In the 1993 rate case, power purchases and secondary energy sales for each of the 50 Water Years were governed by current and projected reservoir levels, specified in terms of energy, relative to a critical rule curve, a fish curve, an energy content curve, and a flood control curve specified in terms of energy. These rule curves specified in terms of energy implicitly assume constant water-to-energy conversion factors. In contrast, HydroSim uses a different set of rule curves for each of the 50 Water Years to more accurately reflect conditions for that particular water year. These rule curves are specified in ksfd.

estimating energy deficits, energy surpluses, and forced operational spill during each of the 50 Water Years. It makes hydro operation decisions based on a large amount of information that impacts the output of each of the dams on the Pacific Northwest Coordinated Hydroelectric System. Results from HydroSim reflect the composite impact that the various monthly hydro operation constraints on each of the dams, the various monthly levels of water that flow behind each of the dams, and the differences in the level of water stored behind each of the dams have on hydro production and reservoir operations. For instance, in HydroSim, energy deficits occur when, after considering inflows, firm loads cannot be met because reservoir operation constraints will not allow further drafting of reservoirs. Energy surpluses occur when streamflows, reservoir storage limitations, and/or operational requirements force generation levels that exceed firm load requirements. Forced operational spill occurs when streamflows, reservoir storage limitations, and/or operational requirements force water to be spilled at some dams, but not others.

Another improvement made to the STREAM is the incorporation of the May Water Budget Storage in Williston, British Columbia, and Non-Treaty Storage in Upper Columbia reservoirs. This allows the STREAM, like actual hydro operations and the NFRAP, to utilize additional storage alternatives available to BPA to mitigate its power purchase expenses and store secondary energy that might be either sold at very low nonfirm prices or spilled. For instance, storage arrangements for Williston Reservoir involve storing 400 MW-mo. of energy in the month of May and another 400 MW-mo. of energy in the month of June (when streamflows are high) and removing 400 MW-mo. of energy in August and another 400 MW-mo. of energy in September (when streamflows are usually low). Non-Treaty Storage provides similar options, but typically in other months.

Since the 1993 rate case, revisions have been made to the way the STREAM uses fossil fuel prices in estimating monthly decremental costs for gas-fired generation. Subsequent analyses had indicated that the seasonal shape of gas prices reflected in BPA’s gas price forecast was not being properly reflected in the monthly decremental costs for the “Normal” and “Surprise” cases. Accordingly, this was corrected by developing and incorporating into the STREAM an array of monthly gas price adjustors that are applied to both the “Normal” and “Surprise” cases.

Another change for the 1996 rate case is that the values for the DSI shift, shift obligation, and advance energy were set to zero, which effectively renders the logic inactive. Due to

Finally, computer code in the STREAM was revised to expand the number of years of data for loads, resources, and so on from one year to the number of years in  the rate period (five years).  In the 1993 rate case, only one set of loads, resources, and so on was used for the 2-year rate period