2007 Supplemental Wholesale Power Rate Case Initial Proposal

SUPPLEMENTAL
SECTION 7(b)(2) RATE TEST STUDY

February 2008

WP-07-E-BPA-50

This page intentionally left blank

SECTION 7(b)(2) RATE TEST STUDY

TABLE OF CONTENTS

Page

This page intentionally left blank.

COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COU	Consumer Owned Utility
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program

DROD	Draft Record of Decision
DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator

JP	Joint Party
JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRA	Load Reduction Agreement
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement

MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool

PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PS	Power Services (formerly Power Business Line)
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load

Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
TS	Transmission Services (formerly Transmission Business Line)
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

This page intentionally left blank.

1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison of the projected rates to be charged its public body, cooperative, and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing 4 years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from costs resulting from certain specified provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the loads of Priority Firm Power (PF) preference customers to other BPA firm, adjustable rate loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative, and Federal agency customers (collectively, the 7(b)(2) Customers). The two sets of rates are: (1) a set for the test period and the ensuing four years assuming that section 7(b)(2) is not in effect (known as Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (known as 7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from both the Program Case and 7(b)(2) Case rates. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the simple average of the Program Case rates is greater than the simple average of the 7(b)(2) Case rates, the rate test triggers. The difference between the average of the Program Case rates and the

average of the 7(b)(2) Case rates determines the amount to be reallocated from the 7(b)(2) Customers to other BPA loads in the rate test period.

1.1 Purpose and Organization of Study

The purpose of this Study is to describe the application of the *Section 7(b)(2) Implementation Methodology (Implementation Methodology)* and the results of such application. The accompanying Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-07-E-BPA-50A, contains the documentation of the computer models and data used to perform the 7(b)(2) rate test.

This Study is organized into three major sections. The first section provides an introduction to the study, as well as a summary of the section *7(b)(2) Legal Interpretation* and *Implementation Methodology*. The second section describes the methodology used in conducting the rate test. It provides a discussion of the calculations performed to project the two sets of power rates that are compared in the rate test. The third section presents a summary of the results of the rate test for the Supplemental Proposal. The appendix to the study provides documentation on the financing benefit assumptions (Appendix A – Financing Analysis).

1.2 Basis of Study

1.2.1 Legal Interpretation

Prior to the first phase of the 1985 general rate case, BPA published the *Legal Interpretation of Section 7(b)(2) of the Northwest Power Act*, 49 Fed. Reg. 23,998 (1984). BPA is currently proposing a revised *Legal Interpretation* as part of the WP-07 Supplemental Proceeding. Parties who wish to comment on the proposed *Legal Interpretation* are invited to file briefs in this docket. Major provisions of the *Legal Interpretation* are listed below.

- The 7(b)(2) Case is modeled by limiting the differences between the Program Case and the 7(b)(2) Case to the five assumptions specified in section 7(b)(2) and the secondary effects of those assumptions, and reflecting the effects of these assumptions on the ratemaking processes that remain the same between the Program Case and the 7(b)(2) Case.

- BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3) of the Northwest Power Act, in a manner that is consistent with section 7(a) of the Northwest Power Act.

- Applicable 7(g) costs are subtracted from the Program Case and the 7(b)(2) Case rates before those rates are compared.

- "Within or adjacent" direct service industrial (DSI) customer loads are assumed to be served by the 7(b)(2) Customers for the entire rate test period.

- "Within or adjacent" DSI loads assumed to be served by the 7(b)(2) Customers are assumed to be served wholly with firm power purchased from BPA.

- Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI loads are "within or adjacent" to 7(b)(2) Customer service areas, with modifications to reflect the actual status, either of BPA service to the DSIs or change of situation in local service area or electrical connection.

- To determine "Federal Base System (FBS) resources not obligated to other entities," DSI loads not "within or adjacent" are assumed to receive service from non-7(b)(2) Customers.

- Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) Case, to meet the 7(b)(2) Customers' loads after the Federal Base System (FBS) resources are exhausted. Specific additional resources are assumed to be used in the order of least cost first; generic resources are then used if necessary.

1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on *Implementation Methodology* issues. The section 7(i) hearing was held as the first phase of the 1985 general rate case. The issues addressed in the hearing are discussed in the *Administrator's Record of Decision for Section 7(b)(2) Implementation Methodology* (7(b)(2) ROD), published in August 1984, and included the adopted *Implementation Methodology*. BPA is currently proposing a revised *Section 7(b)(2) Implementation Methodology* as part of this Supplemental Proposal. The major issues resolved in the 7(b)(2) ROD are discussed below.

- Reserve benefits provided under the Northwest Power Act are quantified using the same value of reserves analysis used in the relevant rate case, modified to reflect that "within or adjacent" DSI loads may be less than the total amount of DSI loads served by BPA. (*See* Wholesale Power Rate Development Study (WPRDS), WP-07-FS-BPA-05, Appendix B.) The proposed *Implementation Methodology* allows for reserves from sources other than DSIs subject to the criteria listed therin. However, within this Supplemental Proposal, reserve benefits provided under the Northwest Power Act are forecast to be zero. These circumstances eliminate the need for a financing benefits analysis to quantify the value of reserves for this rate case.

- Financing benefits in the 7(b)(2) Case are quantified for planned or existing Type 1 or Type 2 resources that have been acquired by BPA or are planned to be acquired in the

Program Case during the 7(b)(2) rate test period. The financing benefits in the 7(b)(2) Case are estimated by BPA's Financial Advisor, Public Financial Management, which estimates the sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did not acquire the resource output. Without the financing benefits that are present in the Program Case, the resources required to meet the 7(b)(2) Customers' loads in the 7(b)(2) Case could be more expensive. When ownership of a resource is by non-preference customers, or is unidentifiable, (Type 3 resources) the proposed *Implementation Methodology* states that the financing benefits analysis does not apply.

- Secondary effects result from reflecting the five specific section 7(b)(2) assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both cases. Two secondary effects are identified for possible modeling in the rate test: the level of surplus firm power available, and the amount of marketed secondary energy. The proposed *Implementation Methodology* removes elasticity of demand as a natural consequence.

- The 7(b)(2) rate test in this rate case is conducted using a single automated Excel ® spreadsheet called RAM2007. The outputs of this spreadsheet model are in the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-50A. The sequence of steps used to conduct the rate test is outlined below in Section 2.1.

- The projected rates for each year of the section 7(b)(2) rate test period is discounted back to the first year of the rate proposal test period using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates then are averaged for each Case and the result rounded to the nearest tenth of a mill. The rate test triggers if the simple average of the discounted rates for the Program Case exceeds the simple average of the discounted rates for the 7(b)(2) Case by one tenth of a mill or more. If the rate test

triggers, the difference between the two rates is multiplied by the projected billing determinants of PF Preference customers in the rate period to determine the amount of costs to be reallocated from the preference customers to other BPA loads in the test year.

2. METHODOLOGY

Implementing section 7(b)(2) consists of incorporating the determinations from the proposed *Legal Interpretation* and proposed *Implementation Methodology* into the RAM2007 model.

2.1 Sequence of Steps

The Rate Design Steps of RAM2007 carry out BPA's ratemaking process by performing the steps needed to develop wholesale power rates and is used as the Program Case for the 7(b)(2) rate test. The 7(b)(2) Case steps of RAM2007 carry out BPA's ratemaking process with changes to reflect the five 7(b)(2) assumptions.

2.1.1 Program Case in RAM2007

RAM2007 calculates annual Program Case rates for the Supplemental Proposal rate period (FY 2009) and the following four years FY 2010-2013. The method of calculating rates and the data used to calculate rates for the Program Case of the 7(b)(2) rate test are identical to those used in calculating the actual proposed rates for the one-year rate period.

2.1.1.1 Sales

The sales forecast used to develop rates for the Program Case covers the period FY 2009-2013, and is the same forecast used to develop BPA's proposed rates. Sales forecasts were developed for the region's consumer-owned utilities (COUs) by aggregating utility-specific forecasts for those customers. The forecast Residential Exchange Program (REP) loads were obtained from

the information provided by the utilities. *See* WPRDS, WP-07-E-BPA-49, Section 8.1.3. For purposes of the 7(b)(2) rate test, BPA is forecasting it will sell no power to the DSIs under the IP rate schedule. Sales to Federal agencies and capacity/energy exchanges are contractually determined and are entered into RAM2007.

BPA's total sales obligations are comprised of COU, investor-owned utility (IOU), DSI, Federal agency, REP, and FPS contractual sales. All PF, IP, and NR forecast sales are entered into RAM2007 with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the Load Resource Study, WP-07-E-BPA-45, and Load Resource Study Documentation, WP-07-E-BPA-45A, and WPRDS Documentation, WP-07-E-BPA-49B.

2.1.1.2 Load/Resource Balance

RAM2007 does not perform a Federal system load/resource balance calculation for the Program Case. Instead, the model depends on the load/resource balance performed in the Load Resource Study, WP-07-E-BPA-45. Data from the Load Resource Study, WP-07-E-BPA-45, are used to calculate the energy allocation factors (EAFs) to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves PF loads (COU, Federal agency, and REP loads) until FBS resources are exhausted. Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining REP and new resources are used to serve this combined rate pool.

2.1.1.3 Revenue Requirement

FBS costs are based on the net interest and depreciation associated with the Federal investment in the hydro projects; planned net revenues; hydro operation and maintenance expenses; annual

costs related to the Columbia Generating Station, WNP-1 and WNP-3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Trojan nuclear plant; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. REP resource costs are based on the average system costs (ASCs) of utilities participating in the REP, including cost adjustments if there are deeming utilities. New resource costs are those of the long-term generating contracts and renewable resources not designated as FBS replacements. Conservation costs include operating expenses, amortization, net interest and planned net revenues associated with the investment in BPA legacy conservation, conservation augmentation, and energy efficiency programs. Other BPA costs include Power Services and agency administrative and general expenses and depreciation, net interest, and planned net revenues associated with Power Services and agency investment in capital equipment. Transmission costs are the annual expenses associated with Power Services' purchase of BPA and non-Federal transmission and ancillary services.

2.1.1.4 Cost Allocation

Allocation of projected costs to customer classes is performed on an average energy basis in RAM2007. Generation costs are allocated by the use of EAFs calculated using the results of the Load Resource Study, WP-07-E-BPA-45. Conservation and billing credit costs, BPA's administrative and general expenses, and energy service business costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those used to develop BPA's proposed rates. *See generally* WPRDS, WP-07-E-BPA-49.

2.1.1.5 Rate Design

The adjustments made to allocated costs in RAM2007 for the Program Case are the same as those made to develop BPA's proposed rates. These include adjustments for: (1) secondary and other revenue credits; (2) the surplus firm power revenue surplus/deficiency; (3) the

section 7(c)(2) delta and margin; and (4) the DSI floor rate adjustment. These rate design adjustments are discussed below in brief. Fuller descriptions are in the WPRDS, WP-07-E-BPA-49.

Secondary and Other Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 50 water years for secondary energy generation capability. Secondary revenues are credited to loads served by FBS and new resources. RAM2007 uses the secondary energy sales revenue forecast produced by the Supplemental Risk Analysis Model (RiskMod), documented in the Risk Analysis Study, WP-07-E-BPA-48.

The Surplus Firm Power Revenue Surplus/Deficiency results when available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term convertible contracts are in an exchange or power mode depending on the circumstances of the individual contracts. The Supplemental Proposal assumes that all convertible contracts are in the exchange mode. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after adjusting for transmission costs, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources. The revenues from capacity sales are included in the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources.

The 7(c)(2) Adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the Value of Reserves credit and the typical margin adjustment. The net margin is 0.573 mills/kWh in nominal dollars.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the IP rate in effect for Operating Year (OY) 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the

IP rate is below that floor rate, the IP rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

2.1.2 7(b)(2) Case in RAM2007

The 7(b)(2) Case section of RAM2007 calculates 7(b)(2) Case rates the same way as Program Case rates, except where section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales

The sales forecasts input to RAM2007 to calculate rates for the 7(b)(2) Case are the same sales forecasts used in the Program Case, with the following modifications. The 7(b)(2) Case utility sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation, and billing credits. This upward adjustment in the utility sales forecast includes annual programmatic conservation resources that have an amortized lifetime that includes the rate case test year of FY 2013. Programmatic conservation resources with amortized life times that end before FY 2013 are assumed to be obsolete and have been removed from the 7(b)(2)(D) resource stack and have no effect on the 7(b)(2) sales forecast. The 7(b)(2) Case also excludes REP loads. Sales to "within or adjacent" DSIs, adjusted to exclude estimates of the Conservation/Modernization program, are assumed to be transferred to the service territories of the 7(b)(2) Customers for the entire rate test period as 100 percent firm loads. Sales to DSIs not "within or adjacent" are assumed to transfer to non-7(b)(2) Customers. For the rate test period, no power sales to DSIs are forecast for the Program Case, and thus no DSI loads are added in the 7(b)(2) Case.

2.1.2.2 Resources

The size of the FBS is identical for the Program Case and the 7(b)(2) Case. However, RAM2007 currently models this in such a way that the FBS that is available to serve requirements load is shown as slightly larger in the 7(b)(2) Case. This is because of the treatment of "other obligations" served in the Program Case that were not in existence at the time of the passage of the Northwest Power Act and are not served in the 7(b)(2) Case. If the FBS is insufficient to serve 7(b)(2) Customer loads through the test period in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the Implementation Methodology, three types of additional resources can be added to serve 7(b)(2) Customer loads. Type 1 resources are actual and planned acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. Type 2 resources are existing resources of 7(b)(2) Customers not dedicated to serving regional loads pursuant to section 5(b) of the Northwest Power Act. These first two types of resources include any BPA programmatic conservation and are used to serve remaining 7(b)(2) Customer load in order of least cost first. Type 3 resources are any additional needed resources priced at the average cost of resources acquired by BPA from non-7(b)(2) Customers consistent with the Program Case. These resources are brought on-line if the first two types of resources are insufficient to meet the 7(b)(2) Customer requirements in the 7(b)(2) Case. Consistent with a proposed clarification in BPA's *Legal Interpretation*, the portions of the Mid-Columbia hydro resources that are contracted to regional IOUs are dedicated to regional loads for purposes of the 7(b)(2) rate test. Therefore, these resources are no longer Type 2 resources and have been removed from the 7(b)(2)(D) resource stack.

2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Public Financial Management. The financial advisor's analysis is Appendix A to this Study. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources

by public utilities is 19 basis points lower than the 7(b)(2) Case without BPA backing using 25-year term financing. The financing benefit of BPA backing for conservation resources in the Program Case would be 18 and 17 basis points lower than the financing costs in the 7(b)(2) Case if financing terms of 20 and 15 years were used. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost of the 7(b)(2) Customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 5 basis points between an assumed revenue bond issued with and without a BPA contract for the Project.

2.1.2.4 Load/Resource Balance

The 7(b)(2) Case section of RAM2007 adjusts the established load/resource balance from the Program Case to comport with the different loads and resource use restrictions assumed in the 7(b)(2) Case. The Program Case is in load/resource balance during the rate period. The size of the FBS, including the balancing purchase power and augmentation purchase power, are the same in the 7(b)(2) Case as in the Program Case. In addition, the Program Case assumes a small amount of new resources that are not assumed in the 7(b)(2) Case. The 7(b)(2) Customer loads are larger than the Program Case PF loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred. The larger 7(b)(2) Customer loads in the 7(b)(2) Case results in the need to select additional resources from the 7(b)(2)(D) resource stack.

2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case is comprised of the same types of costs and budget information as in the Program Case, with some modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts for conservation and energy efficiency, billing credits, new resources, and the REP. The only applicable section 7(g) costs that are present in the Program Case revenue requirement are the amounts for conservation and energy efficiency and billing credits. By removing these costs from the initial 7(b)(2) Case revenue requirement,

the applicable 7(g) costs have been removed from the 7(b)(2) Case. These applicable 7(g) costs are removed from the Program Case just prior to the two Cases are being compared. This is discussed further in Section 3.3 below. In addition, the contracts excluded from the 7(b)(2) Case (contracts not existing on the effective date of the Act) provide no revenues. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same procedures as the Program Case.

2.1.2.6 Cost Allocation

7(b)(2) Customers are allocated FBS and resource stack costs according to their use of the respective resources. FBS obligations are allocated costs according to their use of the FBS.

2.1.2.7 Rate Design

Rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case. However, there is no 7(c)(2) delta or floor rate in the 7(b)(2) Case because there are no DSI loads. Also, the costs of the Conservation Rate Credit (CRC) are not added into the 7(b)(2) Case rates.

3. SUMMARY OF RESULTS

The results for the two Cases are summarized in Tables 1 and 2 below.

3.1 Program Case

The Program Case rate for each year is based on the costs of the resources used to serve the 7(b)(2) Customers. The resource costs are then adjusted as described above and in the WPRDS, WP-07-E-BPA-49. Table 1 below shows the projection of undiscounted nominal Program Case rates.

3.2 7(b)(2) Case

The annual amount to be paid by 7(b)(2) Customers for their power needs in the 7(b)(2) Case is based on the cost of FBS resources and the cost of additional resources from the 7(b)(2)(D) resource stack. These power costs include adjustments for reserves and financing, *i.e.*, the absence of the reserve benefits and financing benefits implicit in the cost of power in the Program Case. The power costs are then subject to the same cost and revenue adjustment allocations as the Program Case rates. Table 2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

3.3 The Section 7(b)(2) Rate Test

RAM2007 performs the section 7(b)(2) rate test after it calculates the two sets of test period rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs for each year. The applicable 7(g) costs are described in section 7(b)(2) as "conservation, resource and conservation credits, experimental resources and uncontrollable events." The applicable 7(g) costs quantified for BPA's rate test are comprised of BPA's acquired and projected conservation, energy efficiency, and CRC costs, and the cost of billing credits. As outlined above in Section 2.1.2.5, applicable 7(g) costs were removed from the 7(b)(2) Case revenue requirement. If there were uncontrollable event costs present in the Program Case revenue requirement, they also would have been excluded from the 7(b)(2) Case revenue requirement. Because these costs are excluded/subtracted from the 7(b)(2) Case at its inception by excluding them from the revenue requirement, there is no need to subtract them at this point in performing the rate test. This explains why "Table 2 - 7(b)(2) Case Rates" does not have an amount of 7(g) costs to be subtracted. The projected rates for each year then are discounted to the beginning of FY 2009 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's forecast borrowing rates that were used in the discounting procedure and the corresponding

cumulative discount factors. When applied to the rates in the two Cases, the simple average of the discounted rates over the test period is calculated, rounded to one decimal place, and compared. As shown in Table 4, the rate test triggers by 5.2 mills/kWh. Therefore, a FY 2009 rate adjustment, valued at about $327 million, is required.

TABLE 1
PROGRAM CASE RATES

(nominal mills/kWh)

Fiscal Year	Rate	Applicable 7(g) Costs	Net Rate
2009	31.26	1.26	30.00
2010	32.25	1.37	30.88
2011	34.13	1.41	32.72
2012	33.57	1.30	32.27
2013	35.41	1.34	34.07

TABLE 2
7(b)(2) CASE RATES

(nominal mills/kWh)

Fiscal Year	7(b)(2) Rate
2009	31.02
2010	24.16
2011	24.64
2012	22.80
2013	24.10

TABLE 3
DISCOUNT FACTORS FOR THE RATE TEST

Fiscal Year	Annual BPA Borrowing Rate[1]	Cumulative Discount Factor[2]
2009	.0654	.9386
2010	.0678	.8790
2011	.0684	.8227
2012	.0684	.7700
2013	.0673	.7214

[1] Final Revenue Requirement Study Documentation, WP-07-E-BPA-02A, Chapter 6.

[2] $DiscFact_t = DiscFact_{t-1}/(1 + BorrowRate_t)$; Fiscal Year 2006 equals 1.

TABLE 4
COMPARISON OF RATES FOR TEST

(2002 mills/kWh)

Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2009	28.16	29.12
2010	27.14	21.24
2011	26.92	20.27
2012	24.85	17.56
2013	24.58	17.39
Average Rate	26.3	21.1
Difference of Average Rates	5.2	

Attachment A

Legal Interpretation of Section 7(b)(2) of the
Pacific Northwest Power Planning and Conservation Act

DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act

I. Background

A. Relevant Statutory Provisions

BPA is charged with the responsibility of implementing section 7(b)(2) of the Northwest Power Act. An agency's interpretation of the statute it is charged to administer is entitled to great deference; in particular, the United States Supreme Court has held that "it is clear that the Administrator's interpretation of the Regional [Northwest Power] Act is to be given great weight." *Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 389 (1984).

Basic principles of statutory construction must be followed in interpreting the Northwest Power Act. These principles require that particular provisions of a statute be interpreted to give effect to its overall purposes. *United States v. Am Trucking Ass'n*, 310 U.S. 534, 543 (1950). Wherever possible, statutory provisions should be construed so as to be consistent with each other. *Adams v. Howerton*, 673 F.2d 1036, 1040 (9th Cir. 1982), cert. denied, 458 U.S. 1111 (1982). Thus, BPA interprets the Northwest Power Act in a manner which seeks consistency among the requirements of each section of the Northwest Power Act.

In addition to the Northwest Power Act, BPA is governed by the Bonneville Project Act. 16 U.S.C. § 832, *et seq.*, the Federal Columbia River Transmission System Act, 16 U.S.C. § 838 *et seq.*, and the Flood Control Act of 1944, 16 U.S.C. § 825 *et seq.* These statutes require BPA to set rates, in accordance with sound business principles, at levels sufficient to recover BPA's total system costs, including repayment of the Federal Treasury investment in the Federal Columbia River Power and Transmission System. All statutory provisions concerning the timely recovery of BPA's revenue requirement are relevant to the interpretation of the Northwest Power Act. For "[w]hen there are two acts upon the same subject, the rule is to give effect to both if possible." *Morton v. Mancari*, 417 U.S. 535, 551 (1974), quoting *United States v. Borden Co.*, 308 U.S. 188, 198 (1939).

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, contains a number of directives that the BPA Administrator must consider in establishing rates for the sale of electric energy and capacity and for the transmission of non-Federal power. Section 7(b)(2), commonly referred to as the "rate test," is one of these directives. Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. § 839e(b)(2), provides:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers exclusive of amounts charged such customers under subsection 7(g) of this section for the costs of

conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that--

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were--

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b),

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from--

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this Act

were not achieved.

16 U.S.C. § 839e(b)(2).

B. Scope of Interpretation

This Legal Interpretation resolves only the basic legal issues necessary to implement section 7(b)(2) and modifies the first Legal Interpretation issued June 8, 1984. *See* Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984).

II. Interpretation

A. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this interpretation, unless further defined.

1. Relevant Rate Case: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. General Requirements: The public body, cooperative and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. 7(b)(2) Customers: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz*, public bodies, cooperatives, and Federal agencies.

4. Applicable 7(g) Costs: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSI) that are forecast to be served by BPA, during the Five-Year Period, pursuant to sections 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to startup and serve load during unexpected conditions.

B. General Approach and Specific Issues of Interpreting Section 7(b)(2)

Section 7(b)(2) assures that 7(b)(2) Customers are charged no more for their General Requirements after July 1, 1985, than they would have been charged if the Five Assumptions were to be realized. These assumptions direct BPA to hypothesize power supply arrangements between itself and its customers that are quite different from reality. Implementation of the Five Assumptions listed in section 7(b)(2) is by nature an exercise in speculation. This interpretation was undertaken to reduce this inherent speculation insofar as possible.

1. Interpretation: Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

Discussion:

The Northwest Power Act provides that after July 1, 1985, the 7(b)(2) Customers' power costs "may not exceed … as determined by the Administrator" the power costs for General Requirements based on the enumerated Five Assumptions. 16 U.S.C. § 839e(b)(2). This language grants the Administrator discretion to determine the manner in which the Five Assumptions of section 7(b)(2) are applied and the rate test is implemented. However, BPA recognizes that the reasonableness of methodologies used to implement section 7(b)(2) will be tested in the Relevant Rate Case.

The Administrator will exercise his discretionary authority in the following manner. Except for the Five Assumptions specified in section 7(b)(2), all underlying premises will remain constant between the Program Case and the 7(b)(2) Case. Assumptions not specified by the statute will not be considered. Secondary effects, however, of the Five Assumptions will be given full recognition in the modeling of the 7(b)(2) Customers' power costs in the 7(b)(2) Case. This general approach will allow the 7(b)(2) Case to be modeled under the same accepted ratemaking techniques used in the Program Case. This approach will also avoid the modeling of a hypothetical world that attempts to reflect in extreme detail what would have occurred had the Northwest Power Act not been enacted.

The legislative history of the Northwest Power Act supports limiting the assumptions of the 7(b)(2) Case to those specified in the statute. The House Committee on Interstate and Foreign Commerce Report accompanying S. 885 (the bill that became the Northwest Power Act) notes that "[t]he assumptions to be made by the Administrator in establishing this ceiling are specifically set forth." H. Rep. No. 976-I, 96th Cong., 2d Sess. 68 (1980). Similarly, the Report of the House Committee on Interior and Insular Affairs declares that "[s]ubsection 7(b)(2) establishes a 'rate ceiling' for BPA's preference customers, and specifies the method of calculating this ceiling…" H. Rep. No. 976-II, 96th Cong., 2d Sess. 52 (1980).

Legislative history also supports including the unavoidable secondary effects of the assumptions listed in the Northwest Power Act. In particular, in addressing Reserve Benefits, Appendix B to the Report of the Senate Committee on Energy and Natural Resources provides that in addition to costs specifically described in sections 7(b)(2)(B) and (D), the Administrator is to consider "[a]ny other general system operating costs, including reserves…" S. Rep. No. 272, 96th Cong., 1st Sess. (1979), Appendix B at 58.

As an illustration of the secondary effects referred to above, BPA has identified two secondary effects of the Five Assumptions found in section 7(b)(2). These effects involve surplus levels and secondary energy markets. The secondary effects must be included in section 7(b)(2) methodologies as natural consequences of the Five Assumptions in section 7(b)(2) on the results of underlying premises that are held constant between the Program Case and the 7(b)(2) Case. Surplus levels and the secondary energy market must change as a natural consequence of the Five Assumptions. As the DSIs are assumed to shift to the private utilities and 7(b)(2) Customers under section 7(b)(2), BPA's load/resource balance changes. This change will affect the level of BPA's surplus. The secondary energy market will also change; the top quartile of DSI Loads will not be served by BPA's secondary energy.

Section 7(b)(2) requires BPA to assume that the 7(b)(2) Case is identical to the Program Case except for those differences required by the Five Assumptions set out in section 7(b)(2)(A)-(E). Present modeling techniques used in the Program Case, which will be used in the modeling of the 7(b)(2) Case, incorporate secondary effects.

2. Interpretation: Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

Discussion:

BPA will conscientiously follow the requirements of section 7(b)(2) to perform the "rate test" for its public body, cooperative and Federal agency customers. If the results of the rate test indicate that BPA must recover costs in excess of those allowed under section 7(b)(2), BPA will implement the section 7(b)(3) supplemental rate charge provision for that purpose. BPA's concern is that failure to recover some, or all, of the reallocated costs "through supplemental rate charges for all other power sold by the Administrator to all customers" may result in BPA's inability to meet the requirements of section 7(a). Such a determination, if it occurs, would be rigorously documented and exposed to careful review during the section 7(i) process for the Relevant Rate Case. Should this occur, BPA would be forced to resolve a possible conflict among sections 7(b)(2), 7(b)(3), and 7(a).

Section 7(a) of the Northwest Power Act requires that BPA rates recover the costs of the electric power and transmission systems, including the repayment of Federal Treasury investments in those systems. Section 7(a) reaffirms this long-standing obligation which was articulated earlier in the Bonneville Project Act and the Federal Columbia River Transmission System Act. Section 7(b)(2) must be applied in a manner which enables BPA to set rates at levels sufficient to recover costs, or the rates will not receive confirmation and approval from the Federal Energy Regulatory Commission. *See* 16 U.S.C. § 839e(a)(2).

The legislative history of the Northwest Power Act supports application of section 7(b)(2) in a manner consistent with BPA's primary statutory obligation that its rates recover costs. The House Interior Committee report declares that:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates: [report continues by setting out rate structure of the Act].

H. Rep. No. 976-11, 96th Cong., 2d Sess. 36 (1980).

Section 7(a)(2) illustrates the importance of BPA's statutory obligation to set rates at levels sufficient to collect its costs. Section 7(a)(2) states that FERC cannot approve BPA's rates unless the rates "are sufficient to assure repayment of federal investment in the Federal Columbia

River Power System over a reasonable number of years after first meeting the Administrator's other costs," 16 U.S.C. § 839e(a)(2)(A), and "are based upon the Administrator's total system costs…" 16 U.S.C. § 839e(a)(2)(B). Indeed:

> BPA is a self-financed agency under the terms of the Federal Columbia River Transmission System Act of 1974. This means that BPA receives no appropriations. It is required by law to cover its full costs through its own revenues derived from the sale of power and other services… The United States of America does not stand behind BPA's obligations. … BPA alone must meet these obligations, and BPA's rates cannot be approved by FERC unless they are sufficient to meet these obligations. These requirements, and the lack of any Federal guarantees, are made explicit in sections 6(j) and 7(a) of S 885, even though they are also explicit in the Federal Columbia River Transmission System Act.

126 Cong. Rec. H9843 (daily ed. Sep. 29, 1980) (statement of Rep. Ullman).

BPA is neither predetermining the results of the rate test nor suggesting a disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a), 7(b)(2), and 7(b)(3). BPA is merely attempting through this interpretation to alert its customers and the public to one possible problem which may present itself in the future.

3. Interpretation: Applicable 7(g) Costs are to be excluded from the Program Case rates and the 7(b)(2) Case rates prior to comparison with the 7(b)(2) Case rates.

Discussion:

Section 7(b)(2) states: "…the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, … an amount equal to the power costs for general requirements of such customers if the Administrator assumes…" the Five Assumptions. 16 U.S.C. § 839e(b)(2).

The foregoing language describes the basic comparison of the Program Case and the 7(b)(2) Case in performing the section 7(b)(2) rate test. In particular, it sets forth the instructions on how BPA is to initially construct the two revenue requirements that will serve as the foundation of the rate test comparison. The language begins with the Program Case. The revenue requirement in the Program Case rate is to be constructed from the "projected amounts to be charged for firm power" for the "general requirements" of BPA's preference customers. This phrase refers to the firm power costs BPA is proposing to recover through its 7(b) rates. Thus, BPA is to start with its total revenue requirement in the Program Case.

The statutory language further directs BPA to modify this revenue requirement by excluding "the amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events…" In other words, BPA must subtract the identified 7(g) costs (referred to hereafter as Applicable 7(g) Costs) from the Program Case revenue requirement. This reduces the revenue requirement in the Program Case, resulting in the power costs to be recovered in the Program Case.

The second half of the above-noted language then describes how BPA is to initially construct the revenue requirement in the 7(b)(2) Case. Specifically, the 7(b)(2) Case revenue requirement is equal to "the power costs for general requirements of such customers…" as modified by the Five Assumptions. The phrase "power costs for general requirements of such customers" is a direct reference back to the same power costs, general requirements, and customers discussed in the earlier clause when calculating the costs of the Program Case. The only substantive textual difference between this clause and the previously discussed language is the reference to "power cost." That difference, however, is immaterial because the phrase "power costs" is simply a short-hand reference to the longer description of "the amounts to be charged for firm power" used in the preceding section. Because the two clauses are identical in all material respects, the two provisions should be interpreted consistently. Consequently, the same power costs that were used to serve the "general requirements" in the Program Case should be used to construct the revenue requirement for the 7(b)(2) Case; that is, "the projected amounts to be charged for firm power … exclusive of" Applicable 7(g) costs.

This interpretation, in addition to being consistent with the aforementioned statutory text, also makes practical sense when actually implementing the 7(b)(2) rate test. First, having symmetry between the initial power costs in the Program Case and the 7(b)(2) Case ensures that the later application of the Five Assumptions is the central reason the rate test triggers or fails to trigger. Congress specifically identified the Five Assumptions as the factors the Administrator was to "assume" in conducting the rate test. By limiting the cost differences between the Program Case and the 7(b)(2) Case before the application of these assumptions, BPA can give the full and proper effect to the rate test construct envisioned by Congress. Without this symmetry, the rate test results may become skewed by factors other than the Five Assumptions. For example, if Applicable 7(g) costs were excluded from the Program Case (making it less expensive), but included in the 7(b)(2) Case (making it more expensive), it could create a cost incongruity that could become a determinative factor in whether the rate test will trigger. Having an equilibrium between the costs in the Program Case and the 7(b)(2) Case reduces these unintended consequences and preserves the Congressionally identified drivers of the rate test—the Five Assumptions.

Second, this interpretation also avoids potential conflicts with the remaining sections of the 7(b)(2) rate test. Specifically, if the "power costs" used in the 7(b)(2) Case were not interpreted to mean the same power costs in the Program Case, a conflict would occur between the above-mentioned paragraph and section 7(b)(2)(D)(i), the fourth of the Five Assumptions. The fourth assumption specifies that any remaining General Requirements in the 7(b)(2) Case that have not been satisfied by Federal Base System (FBS) resources pursuant to the second assumption (*i.e.*,

section 7(b)(2)(B)) are met with resources taken from a resource stack developed in accordance with subsection 7(b)(2)(D). *See* Issue 11 *supra*.

Section 7(b)(2)(D) provides:

> all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –
> (i) purchased from such customers by the Administrator pursuant to section 6, or
> (ii) not committed to load pursuant to section 5(b),
> and were the least expensive resources owned or purchased by public bodies and cooperatives; and any additional needed resources were obtained at the average cost of all other resources acquired by the Administrator…

16 U.S.C. § 839e(b)(2)(D). Resources that meet the criteria identified in section 7(b)(2)(D) are assumed to be in a "resource stack," available for use to serve the General Requirements of the 7(b)(2) Customers in the 7(b)(2) Case. This resource stack includes three types of resources. Type 1 resources are resources the Administrator acquired or plans to acquire from 7(b)(2) Customers pursuant to section 6 of the Northwest Power Act. Type 2 resources are not committed to load pursuant to section 5(b). Type 3 resources are any remaining needed resources. *See* Issue 11 *supra*. It is the Type 1 resources that create an anomaly in the treatment of 7(g) costs.

When resources are included in the resource stack, they are not used to serve General Requirements in the 7(b)(2) Case unless needed and selected from the stack. Section 7(b)(2)(D) refers to "resources … purchased from such [7(b)(2)] customers by the Administrator pursuant to section 6 [of the Northwest Power Act]." *Id.* Conservation is a resource that is assumed to be available in the resource stack. The Northwest Power Act specifically defines conservation as a resource:

> "Resource" means – electric power, including the actual or planned electric power capability of generating facilities, or actual or planned *load reduction resulting from* direct application of a renewable energy resource by a consumer, or from *a conservation measure*.

16 U.S.C. § 839a(19) (emphasis added). Furthermore, conservation is acquired pursuant to section 6 of the Act. Section 6 provides, *inter alia*, that "[t]he Administrator shall acquire such resources through conservation…" 16 U.S.C. § 839d(a)(1). Therefore, conservation is a Type 1 resource and must be included in the resource stack.

Conservation resources and billing credit resources, however, can only be included in the resource stack if Applicable 7(g) costs are removed from the 7(b)(2) Case. Recall that the Applicable 7(g) costs exclude the cost "*of conservation, resource and conservation credits*, experimental resources and uncontrollable events…" 16 U.S.C. § 839e(b)(2) (emphasis added).

The import of leaving the Applicable 7(g) costs in the 7(b)(2) Case is that the costs of "conservation, resource and conservation credits" will remain in the 7(b)(2) revenue requirement. With conservation costs already in the costs of the 7(b)(2) Case, there is no logical way for conservation resources to be available *again* in the resource stack. To do so would be to effectively double-count the conservation costs – first in the 7(b)(2) revenue requirement (because they were never taken out), and second as the costs of a Type 1 resource (assuming it is selected). The only way to avoid this double-counting is to either remove the conservation costs from the 7(b)(2) Case revenue requirement *or* remove conservation resource costs from the resource stack.

In BPA's view, the more appropriate alternative is the former. Treating conservation as a Type 1 resource gives full effect to section 7(b)(2)(D)(i). The Administrator will be fulfilling the Congressional mandate to include resources in the 7(b)(2) Case resource stack "purchased from such customers by the Administrator pursuant to section 6…," *e.g.*, conservation resources. 16 U.S.C. § 839e(b)(2)(D)(i). By contrast, the latter alternative of removing all conservation costs from the resource stack would completely frustrate the purpose of referring to section 6 resources in section 7(b)(2)(D)(i). The better interpretation is therefore to include conservation as a Type 1 resource. To effectuate this interpretation, Applicable 7(g) costs, which include conservation costs, must be removed from the 7(b)(2) Case revenue requirement.

In summary, BPA will interpret the aforementioned statutory language as meaning that the Program Case and 7(b)(2) Case must begin with the same power costs. That is, the Applicable 7(g) costs will be excluded from both the Program Case and the 7(b)(2) Case prior to application of the Five Assumptions. This interpretation is consistent with the statutory language and the purpose of the section 7(b)(2) rate test. It also avoids unnecessary conflicts with, and gives full effect to, the other provisions of section 7(b)(2).

4. Interpretation: The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

Discussion:

Section 7(b)(2) states: "…during any year after July 1, 1985, plus the ensuing four years, …" and several times thereafter "…during such five-year period…" "Any year," in this context, refers to the period of time applicable to the opening statement of section 7(b)(2), namely, the period over which "the projected amounts to be charged for firm power" is applicable, otherwise known as the revenue recovery period.

BPA has had varying lengths of revenue recovery periods in the 22 years between July 1, 1985, and October 1, 2007. Four times BPA has used two-year periods, twice BPA has used five-year periods, once for one-year, once for three-years, and once for 27 months. In each of these periods, the rate test was performed on the basis that the revenue recovery period was the "first year" of the Five-Year Period. For each of these rate tests, the four years subsequent to the last year of the revenue recovery period were appended to form the Five-Year Period.

It is reasonable to consider that the Five-Year Period might encompass more than 60 months. As noted above, the rate test is to compare the projected amounts to be charged for firm power. In the instance of a revenue recovery period that encompasses more than 12 months, the projected amounts to be charged are developed for the entire revenue recovery period. Therefore, to be consistent with the development of the amounts to be charged, it is reasonable to consider that time period, be it for 12 months or more, the first year of the period of consideration for the rate test.

5. Interpretation: 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume that "the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are: (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives…" 16 U.S.C. § 839e(b)(2)(A). The plain language of section 7(b)(2)(A) requires the Administrator to assume that 7(b)(2) Customers' loads include any Within or Adjacent DSI Loads during the Five-Year Period.

The legislative history of the Northwest Power Act also supports BPA's interpretation of the statute. In the analysis of the section 7(b)(2) directives contained in Appendix B to the Senate Report, S. Rep. No. 272, 96th Cong. 1st Sess., at 65-79 (1979), forecasted DSI Loads were transferred from BPA to 7(b)(2) Customers for the entire test period regardless of contracts in effect as of the effective date of the Northwest Power Act. In the projections contained in Appendix B, calculations of public agency loads for the 7(b)(2) Case included a full 85 percent of projected DSI Loads beginning in 1980 (85 percent was the amount determined to be "Within or Adjacent" to preference agency service areas). Although Appendix B is not conclusive evidence of legislative intent, it was "an important part of the common understanding about how the costs of resources would be distributed as a result of [the Northwest Power Act]." *Id.* at 31. Appendix B is a useful tool for statutory construction where it does not conflict with the language of the statute.

6. Interpretation: BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

Discussion:

Section 7(b)(2)(A) requires the Administrator to assume that during the relevant Five-Year Period, "the public body and cooperative customers' general requirements had included … the direct service industrial customer loads which are … located within or adjacent to the geographic service boundaries of such public bodies and cooperatives…" 16 U.S.C. § 839e(b)(2)(A). It is

not apparent from the statute how BPA is to resolve the question of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries. Therefore, BPA must look to legislative history to resolve the ambiguity.

The legislative history of the Northwest Power Act indicates that a determination of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries was made in Appendix B. S. Rep. No. 272, 96th Cong., 1st Sess., Appendix B at 66. Appendix B includes a table listing the DSIs "within BPA preference customers' service areas," DSIs "adjacent to BPA preference customers' service areas" and those DSIs that "could not readily be served by BPA preference customers." *Id.*

The Within or Adjacent table in the numerical analysis in Appendix B is accompanied by a narrative explanation which states that the loads for establishing resource requirements under section 7(b)(2) will include "DSI total loads within or adjacent to the service territory of the public bodies and cooperatives. (85 percent of existing DSIs as shown in the attached table)." *Id.* at 58. The detailed nature of the Within or Adjacent table and the narrative explanation in Appendix B convince BPA that Congress intended the Appendix B table to be used in resolving which DSIs are Within or Adjacent to the service territory of public body and cooperative customers. The Appendix B table will be disregarded only if conditions of service to those DSI customers change, such as in the case of termination of BPA service to a DSI industrial plant or if the location of the DSI changes from an IOU service territory to a public utility service territory.

Adjacent will be assessed on electrical connections rather than a strictly locational basis. Circumstances may occur where a DSI's location may be outside of a 7(b)(2) Customer's service territory, but a direct electrical connection exists between the DSI and the 7(b)(2) Customer. Conversely, a DSI's location may be inside a 7(b)(2) Customer's service territory, but no direct electrical connection exists between the DSI and the 7(b)(2) Customer. This determination will consider normal operating electrical connections and disregard emergency connections.

7. Interpretation: All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume "that the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customers loads…" 16 U.S.C. § 839e(b)(2)(A). Section 7(b)(2)(A) does not expressly state the nature or quality of service assumed to be provided by the public bodies and cooperatives to the relevant DSI Loads.

The DSI Loads originally served by BPA under the Northwest Power Act included three quartiles that were firm loads and one quartile (the first quartile) that BPA did not plan or acquire resources to serve. However, the language of the Act is compelling that Congress intended all

relevant DSI Loads, assumed to be served by public bodies and cooperatives, to be treated as firm.

Section 7(b)(2)(A) requires BPA to assume that the loads of relevant DSIs are included in the 7(b)(2) Customers' "general requirements," a term defined by section 7(b)(4) of the Northwest Power Act as limited to electric power purchased from the Administrator under section 5(b) of the Act. Section 5(b) deals exclusively with firm power. In addition, sections 7(b)(2)(B) and 7(b)(2)(D) require that FBS and additional resources be assumed to serve the total General Requirements of the 7(b)(2) Customers.

The legislative history of the Northwest Power Act supports interpreting the statute to require 7(b)(2) Customers' firm power General Requirements in the 7(b)(2) Case to include all DSI Loads served by the Administrator. This includes DSI Loads that BPA does not plan or acquire resources to serve (*e.g.*, first quartile service) in the Program Case. In Appendix B, all four quartiles of DSI Loads were treated as firm when assigned to public agency customers in the 7(b)(2) Case.

8. Interpretation: Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

Discussion:

Section 7(b)(2)(B) provides that the Administrator is to assume that 7(b)(2) Customers were served by FBS resources "not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in [Section 7(b)(2)(A)])." 16 U.S.C. § 839e(b)(2)(A). Unlike the assumption relating to DSI Loads served by public body and cooperative customers, section 7(b)(2)(B) requires BPA to make two factual determinations: (1) what the level of FBS resources is, and (2) what level of FBS resources is obligated for service to other entities, for all or a portion of the relevant Five-Year Period. The first determination is necessary because the FBS includes resources purchased by BPA under long-term contracts. Expiration of these contracts may cause a change in the size of the FBS during the relevant Five-Year Period.

The second determination concerns BPA power sales contracts or other obligations existing as of the effective date of the Northwest Power Act. Should these contractual obligations on FBS resources be removed through expiration of the relevant contracts, the size of FBS resources available to 7(b)(2) Customers would increase. Obligations on FBS resources include uses of power mandated by treaty, statute, or contracts entered into by BPA before December 5, 1980. The DSI obligations referenced in subsection 7(b)(2)(B) have since expired, rendering the "excluding obligations" language as no longer effective.

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs.

Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless, and to the extent that, there is surplus FBS in the 7(b)(2) Case.

9. Interpretation: Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(B) states that the Administrator is to assume that "public body … customers were served … with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980 … excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph." 16 U.S.C. § 839e(b)(2)(B).

In the Program Case, section 7(b)(1) sets forth the sequence of allocating resource pools to load pools.

> Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

The hierarchy established by section 7(b)(1), and complemented for other rates in sections 7(c)(1)(A) and 7(f), is that the FBS is to be used first to serve 7(b) loads, then for 7(c) loads and 7(f) loads until the FBS resources are exhausted. After the FBS resources are exhausted, BPA uses power acquired from the section 5(c) exchange to serve remaining loads. After using FBS and exchange resources, other resources acquired by BPA, also referred to as new resources, are used to serve remaining loads.

The Program Case uses this hierarchy to apply the resource pools, and their costs, to the load pools as the method of assigning resource costs to the load pools. However, in the 7(b)(2) Case, the size of the load pools will be different than in the Program Case. For example, section 5(c) exchange loads are removed from the 7(b)(2) Case load pool, thereby creating a smaller 7(b) load pool in the 7(b)(2) Case.

As a result of the different sizes of load pools in the two cases, the 7(b)(2) Case must construct its own separate allocation of resource pools to load pools. Furthermore, because of the explicit exclusion of the section 5(c) exchange in the 7(b)(2) Case, the exchange resource pool is eliminated. Lastly, because additional resources necessary in the 7(b)(2) Case are to be added through the 7(b)(2)(D) resource stack, the new resource resource pool is eliminated from the 7(b)(2) Case. All of these differences will result in different resource cost allocations than in the Program Case.

10. Interpretation: Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(C) states that the Administrator is to assume that "no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period." 16 U.S.C. § 839e(b)(2)(C). This language unmistakably provides that the 7(b)(2) Case is to assume that the Residential Exchange Program is to be excluded from consideration. This includes all aspects of the exchange: the costs, the purchases and the sales. Further, any implementation costs included in the Program Case should be excluded from the 7(b)(2) Case, as should any costs associated with a settlement of residential exchange benefits.

11. Interpretation: Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

Discussion:

Section 7(b)(2)(D) describes the manner in which additional resources are assumed to be acquired to meet the 7(b)(2) Customers' loads when FBS resources are exhausted. Three types of additional resources are available in the 7(b)(2) Case. The first type of resource is described in section 7(b)(2)(D)(i) as being resources that were "purchased from such customers by the Administrator pursuant to section 6." These are the resources actually acquired by BPA from the 7(b)(2) Customers in the Program Case.

Conservation is defined in the Northwest Power Act as a resource. "'Resource' means … actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. § 839a(19). In addition, conservation is acquired by BPA under section 6. "The Administrator shall acquire such resources through conservation, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load…" 16 U.S.C. § 839d(a)(1). Because conservation is acquired from 7(b)(2) Customers, it is a Type 1 resource. Such being the case, section 7(b)(2)(D) requires that any conservation being

acquired by BPA must be included in the resource stack as a non-FBS resource and available to serve 7(b)(2) Customer load to the extent it is needed and it is among the least expensive resources available. *See* Issue 4 *infra*.

Section 7(b)(2)(D)(ii) describes the second type of resource as those "not committed to load pursuant to section 5(b)." These are resources owned or purchased by the 7(b)(2) Customers that are not dedicated to load. Section 5(b)(1) of the Northwest Power Act provides:

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds—(A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1). As noted in section 3(19) of the Northwest Power Act, the term "resource" includes "electric power." 16 U.S.C. § 839a(19). Because section 5(b) applies to requirements determinations for both preference customers and investor-owned utilities, section 7(b)(2)(D)(ii) precludes BPA from including resources owned or purchased by 7(b)(2) Customers in the 7(b)(2) Case resource stack if such resources are committed to load by preference customers or investor-owned utilities.

Together, sections 7(b)(2)(D)(i) and (ii) result in a list of resources which are assumed to be available to meet 7(b)(2) Customer loads. The remainder of section 7(b)(2)(D) outlines how this list of resources is to be used to serve the 7(b)(2) Customers' loads and describes the third type of resources available to meet 7(b)(2) Case loads. BPA is to assume for the 7(b)(2) Case that any required additional resources "were the least expensive resources owned or purchased by public bodies or cooperatives." This means that 7(b)(2)(D)(i) and (ii) resources are stacked in order of cost and pulled from that stack to meet 7(b)(2) Customers' loads in order of least to greatest cost. Should these resources be insufficient to satisfy the General Requirements of 7(b)(2) Customers, section 7(b)(2)(D) provides the assumption that "...any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator." This third resource type consists of the other new resources acquired by BPA in an amount required to meet the 7(b)(2) Customers' remaining loads, the cost of which is determined by the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the relevant Five-Year Period.

12. Interpretation: Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, … were not achieved." 16 U.S.C. § 839e(b)(2)(E). The legislative history adds some clarification to this language. "Costs of new resources, either actual or hypothetical, constructed or acquired by the public bodies and cooperatives as necessary to meet these preference customer load requirements using the financing costs of such agencies that would have resulted if actions of the Administrator under Section 6 of the Bill were not achieved." S. Rep. No. 272, 96th Cong., 1st Sess., Appendix B at 58.

This subsection provides that the 7(b)(2) Case is to assume that the cost of resources in the subsection 7(b)(2)(D) resource stack is to exclude any 7(b)(2) Customer's financing benefits due to BPA's purchase of the output of the resource.

13. Interpretation: Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from … reserve benefits as a result of the Administrator's actions under this chapter were not achieved." 16 U.S.C. § 839e(b)(2)(E). Reserve Benefits result from BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these restriction rights are unavailable to BPA. Without the restriction rights, BPA would have to incur the costs of providing an equivalent amount of reserves from another source. This subsection provides that the 7(b)(2) Case is to assume that cost reductions attributable to Reserve Benefits are not achieved in the 7(b)(2) Case. Therefore, the 7(b)(2) Case revenue requirement is to assume the extra cost of procuring the reserves provided to the Program Case.

Attachment B

Implementation Methodology of Section 7(b)(2) of the
Pacific Northwest Power Planning and Conservation Act

DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act

I. Introduction

The Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act"), 16 U.S.C. § 839, confirms BPA's obligation to establish and revise BPA's rates for the sale and transmission of electric power. Section 7(b)(2) of the Northwest Power Act provides that

> after July 1, 1985, the projected amounts to be charged for firm power for the general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if the Administrator …

makes a set of assumptions, outlined in the remainder of section 7(b)(2). These assumptions hypothetically remove the effects of certain provisions in the Northwest Power Act. In order to implement the provisions in section 7(b)(2), BPA has formulated a methodology that specifies how BPA will conduct the section 7(b)(2) rate test.

The implementation of section 7(b)(2) in any given BPA rate proceeding requires two distinct steps. The first step is to compare a set of annual rates developed under all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2) (the Program Case), with a set of annual rates developed under the assumptions outlined in section 7(b)(2) (the 7(b)(2) Case). Both sets of rates are those applicable to public body, cooperative, and Federal agency customers (7(b)(2) Customers) and are based on the costs of power required to serve the General Requirements of those customers over the Five-Year Period.

If the rates in the Program Case are determined to be higher than those in the 7(b)(2) Case, then rate protection is to be afforded to preference customers and a second step is required. The allocated costs of the 7(b)(2) Customers must be reduced by the amount of rate protection afforded by the rate test and the difference allocated to other BPA rates pursuant to section 7(b)(3) of the Northwest Power Act. This potential reallocation must be made within the framework of sound ratemaking principles and BPA's statutory obligations.

II. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this section, unless further defined.

1. Relevant Rate Case: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. General Requirements: The public body, cooperative and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. 7(b)(2) Customers: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz*, public bodies, cooperatives, and Federal agencies.

4. Applicable 7(g) Costs: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSI) that are forecast to be served by BPA, during the Five-Year Period, pursuant to sections 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to startup and serve load during unexpected conditions.

III. Legal Interpretation

BPA first published a Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act in 1984. 49 Fed. Reg. 23,998 (June 8, 1984). The first Legal Interpretation presented BPA's interpretation of section 7(b)(2) of the Northwest Power Act, incorporating principles of statutory construction and a review of legislative history. In addition, BPA considered the views expressed in a series of informal meetings with interested persons and in comments received in response to the publication of an earlier notice of a draft Legal Interpretation. The scope of the notice was limited to those issues that relied on statutory language or legislative intent for resolution.

Concurrent with the consideration of this revision to the Implementation Methodology, BPA is proposing revisions to the Legal Interpretation. This Methodology incorporates changes to conform to revisions to the Legal Interpretation.

Briefly, BPA interprets section 7(b)(2) as follows:

1. Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

2. Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

3. Applicable 7(g) Costs are to be excluded from the Program Case rates prior to comparison with the 7(b)(2) Case rates.

4. The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

5. 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

6. BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

7. All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

8. Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

9. Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

10. Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

11. Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

12. Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

13. Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

IV. The Program Case

In performing the 7(b)(2) rate test, the Program Case is the Five-Year Period projection of the average annual power rates for serving the General Requirements of the 7(b)(2) Customers conforming with all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2). All rate proposal determinations, decisions and assumptions for the rate recovery period regarding revenue requirements, loads, resources, cost allocation and rate design will be used. All data for the ensuing four years will be consistent with or extrapolated from rate

recovery period data. Ratemaking methodologies, such as those based on the rate directives in the Northwest Power Act and those used to allocate costs and revenue adjustments to BPA customer classes, will be unchanged over the Five-Year Period.

If BPA uses its section 7(e) rate design discretion to implement an alternative tiered rate form, that rate design flexibility will be applied subsequent to the section 7(b)(2) rate test. In such cases, the rate test will continue to be performed with all cost allocated to, and all loads included in, the 7(b) load pool, without respect to the tiering of such costs and loads.

1. Load Forecast

A load forecast will be developed for every BPA rate proposal independent of any requirements for implementing section 7(b)(2). It will include estimates of BPA programmatic conservation savings for the forecast period. The treatment of power sales contracts that expire during the Five-Year Period will be the subject of each Relevant Rate Case. This forecast will provide the load estimates for the Program Case.

2. DSI Loads

A load forecast of purchases by DSIs from BPA will be developed for the Five-Year Period. This forecast, without consideration of the rate schedule under which the power is sold, will define the DSI Loads for the Program Case.

3. Resources

Regional resource generation studies are also conducted for BPA's rate proposals. These studies determine the capability of BPA's and the region's hydro and thermal resources for the Five-Year Period. The resource study results will be consistently applied through the Five-Year Period except as modified to reflect the start of commercial operation or retirement of generating resources and also for the planned effect or expiration of relevant contracts or purchases. Firm and secondary hydroelectric generation will be based on these studies. Assumptions about the level of surplus firm power sales for the Program Case will be the same as those made for the Relevant Rate Case.

4. Revenue Requirements including Residential Exchange Costs

BPA's repayment process will be used for the determination of BPA revenue requirements through the Five-Year Period. Costs will be projected over the Five-Year Period using budget estimates, when available. Estimates of future inflation and real cost escalation and planned additions to BPA's power system will be used when budget estimates are unavailable.

5. Surplus Firm and Secondary Sales

The Program Case establishes the forecast of revenues from surplus power sales, whether the surplus is firm or secondary.

6. Subtracting Applicable 7(g) Costs

Prior to comparing the Program Case rates to the 7(b)(2) Case rates, section 7(b)(2) directs that the Applicable 7(g) Costs are to be subtracted from the Program Case rate. To accomplish this, the amounts of Applicable 7(g) Costs allocated to the 7(b) rate pool will be removed from the Program Case rates. To do so, the allocated Applicable 7(g) Costs will be expressed as a unit rate comparable to the 7(b) rate and will be subtracted from the annual 7(b) rates to calculate the adjusted Program Case rates.

7. Summary Methodology for the Program Case

The procedures and data from the rate proposal cannot be described in detail in this document. They are properly rate case determinations that are outside the scope of the Methodology for implementing section 7(b)(2). The Section 7(b)(2) Methodology must be flexible enough to incorporate the procedures and data from the rate proposal for which the section 7(b)(2) rate test is being conducted. These procedures and data, as part of a BPA rate filing, are in turn subject to review and comment pursuant to section 7(i) of the Northwest Power Act. The Section 7(b)(2) Methodology can require only that the rate proposal procedures and data be modeled or incorporated as accurately as possible, which will be subject to examination during the Relevant Rate Case.

In summary, the Program Case will be BPA's best projection of its rates without considering the effects of section 7(b)(2). The exact procedures for the rate calculation in the Program Case cannot be determined until BPA has prepared its rate proposal. However, the rate test modeling will reflect the rate proposal procedures as completely as possible in producing the Program Case when the rate test is conducted for that rate proposal.

V. The 7(b)(2) Case

The language of section 7(b)(2) not only directs BPA to conduct a rate test for the 7(b)(2) Customers but also provides a considerable amount of direction as to how the rate test is to be conducted. BPA's Legal Interpretation provides the general approach to developing the 7(b)(2) Case. Based on this, the 7(b)(2) Case will be modeled in the same way as the Program Case, except where section 7(b)(2) provides specific assumptions that modify the Program Case. The modeling of these Five Assumptions may lead to different results than the underlying premises and ratemaking processes that will be held constant between the two cases. The remainder of this section outlines how the 7(b)(2) Case rate calculations for the Five-Year Period will be developed.

1. Load Forecast

The initial loads that will be used in the 7(b)(2) Case will be the same General Requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA. Conservation is a resource acquired by the Administrator pursuant to section 6 and, therefore, conservation resources are required to

be included in the 7(b)(2) Case resource stack. Because conservation resources must be included in the resource stack to be drawn to serve remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA. Power sales contracts that expire during the Five-Year Period, except for requirements and DSI contracts, will be recognized as expiring as scheduled. This forecast will provide the load estimates for the 7(b)(2) Case.

2. DSI Loads

DSI Loads will be examined on a plant-by-plant basis to reflect whether or not they are Within or Adjacent. All Within or Adjacent DSI Loads will be included in the General Requirements of the 7(b)(2) Customers during the Five-Year Period. DSI Loads not Within or Adjacent are assumed to be served by private utilities. The forecast operating levels of the DSIs that are transferred to public and private utilities are assumed to be served as 100 percent firm loads.

3. Resources

The FBS and any additional resources, as defined in section 7(b)(2)(D), are the only resources available to serve the General Requirements of the 7(b)(2) Customers. However, the amount of FBS resources available to serve the 7(b)(2) Customers in the Program Case will be reduced by any contractual, statutory, or treaty obligations on these resources that were in existence prior to passage of the Northwest Power Act; statutory and treaty including the Canadian Entitlement return, the Hungry Horse Reservation, and Bureau pumping power. Should these obligations expire, the amount of the FBS available to serve the General Requirements of the 7(b)(2) Customers would increase.

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs. Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless there is an FBS surplus in the 7(b)(2) Case. If the FBS surplus does not allow full recognition of these contracts, then a *pro rata* share of energy and revenues will be recognized in the 7(b)(2) Case.

Any surplus FBS resources remaining after meeting FBS obligations, 7(b)(2) Customer loads, and contracts subsequent to December 5, 1980, will be assumed to be sold in the wholesale energy markets at the forecast price assumed in the Program Case for such sales.

If FBS resources, after meeting obligations, are insufficient to meet the General Requirements of the 7(b)(2) Customers, then three types of additional resources can be added to serve those loads. These additional resources are defined in section 7(b)(2)(D) and are: (a) actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case, including conservation resources; (b) existing 7(b)(2) Customer resources not currently dedicated to regional load by preference customers or IOUs; and (c) all other needed resources,

acquired at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case. The Type 1 and Type 2 resources will be assumed to come online to meet the remaining General Requirements of the 7(b)(2) Customers after FBS service in order of least cost first. The resources will then be brought online in the exact amount required to meet the 7(b)(2) Customers' remaining General Requirements. However, once brought online, the resource will remain online throughout the Five-Year Period, even if loads are lower in subsequent years. In such cases, the excess resources will be assumed to be sold at the average cost of all the excess resources and the revenues credited to the 7(b)(2) Case rates.

4. Revenue Requirement

Except for specific exclusions resulting from the Five Assumptions, the revenue requirement for the 7(b)(2) Case will be the same as the Program Case. The specific exceptions are:

1) all costs related to the Residential Exchange Program will be removed, including the identified BPA costs of implementing the program. Any costs included in the Program Case that are the result of a settlement of Residential Exchange Program claims will also be excluded;

2) all costs of any acquisition of new resources will be removed;

3) Applicable 7(g) Costs will be removed, that is, the costs of conservation, billing credits, experimental resources and uncontrollable events.

In addition to these explicit exclusions, the secondary effects of their exclusion will be considered. Specifically, the Program Case repayment study will be performed without the excluded costs to determine the interest and amortization applicable to the 7(b)(2) Case.

5. Surplus Firm and Secondary Sales

The load and resource situation in the 7(b)(2) Case may be considerably different from that in the Program Case. The increase in the region's firm load due to the 100 percent firm service to Within or Adjacent DSI Loads, a different load forecast for the 7(b)(2) Case due to conservation removal, and a potentially different set of resources all imply that a different level of surplus firm power may be projected for the 7(b)(2) Case than for the Program Case. The level of surplus firm sales in the 7(b)(2) Case will be determined in the same manner as it is in the Program Case. However, any sales of surplus firm power projected to be made in the Program Case to serve interruptible DSI Loads will not be made in the 7(b)(2) Case. Any firm surplus FBS in the 7(b)(2) Case will be assumed to be sold at the average rate of post-Act contract sales in the Program Case. Any difference between costs allocated to surplus firm and revenues from the sale will be allocated to 7(b)(2) Customers.

Secondary energy generation of the region's hydroelectric system will also be assumed to be the same as in the Program Case. However, the secondary energy sales will be increased in the 7(b)(2) Case to reflect additional sales due to the removal of interruptible DSI Load.

6. Financing Benefits

Section 7(b)(2)(E)(1) requires that BPA assume that Quantifiable Monetary Savings to 7(b)(2) Customers resulting from reduced public utility financing costs for the first two types of non-FBS resources described above were not achieved in the 7(b)(2) Case. Therefore, any additional resources required to serve the General Requirements of 7(b)(2) Customers will not reflect the financing cost reductions implicit in resource acquisitions by public bodies.

A list of eligible resources will be developed, containing cost and sponsor information for each resource. For those resources actually acquired by BPA in the Program Case, and for those resources not dedicated to load and assumed available to BPA, BPA will estimate the financing costs for the resource sponsor assuming that BPA had not acquired the resource output. Finally, when detailed financing cost and sponsor information is not available for planned 7(b)(2) Customer resources, BPA will follow the same procedures, assuming projected public sponsored resource costs. Any changes in financing costs determined from this analysis will be included in the costs of the resources in the 7(b)(2) Case.

For conservation resources acquired by BPA, the financing benefits may include an increased amount of debt financing compared to the Program Case. The amount of debt financing assumed in the 7(b)(2) Case will be determined in the Relevant Rate Case.

7. Reserve Benefits

Section 7(b)(2)(E)(ii) requires BPA to assume that the Quantifiable Monetary Savings resulting from Reserve Benefits were not achieved. Reserve Benefits result from BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these restriction rights are unavailable to BPA. Without the restriction rights, BPA would incur the costs of providing an equivalent amount of reserves from another source. Therefore, it will be assumed that BPA will incur a level of costs for the benefit of public utilities based on the value of the reserves provided by the restriction rights to the Program Case as determined in BPA's rate proposal. The value of reserves determination is currently based, in large part, on the cost of an alternative reserve resource. Also, if the level of reserves provided by the restriction rights is insufficient in the 7(b)(2) Case, based on BPA planning criteria, then additional reserve resource costs will be added in the 7(b)(2) Case.

VI. Rate Test Computer Model

Conducting the section 7(b)(2) rate test requires the use of a computer model to develop the rate projections for the Program Case and the 7(b)(2) Case. The exact form of the Program Case procedures cannot be determined until the time of the Relevant Rate Case for which the rate test is being conducted. The 7(b)(2) Case is inextricably linked to the Program Case as a result of the general approach applied to modeling the 7(b)(2) Case. Therefore, to the maximum extent possible, the exact structure and form of the computer model should be the same as used in determining BPA's actual power rates.

VII. Comparison of Rates

For each of the two Cases, the Program and the 7(b)(2), the rate test model will produce a set of annual average energy rates for the Five-Year Period. These two sets of rates will be used to determine if a reallocation of costs pursuant to section 7(b)(3) is required. The relevant rates for the comparison from the Program Case are BPA's average annual 7(b) rate less Applicable 7(g) Costs. The relevant rates from the 7(b)(2) Case are the per kilowatthour power costs of serving the General Requirements of the 7(b)(2) Customers.

The 7(b) rate in the Program Case will be developed in the same manner as it is in BPA's rate proposal. The 7(b)(2) rate in the 7(b)(2) Case will include the costs of resources required to serve the 7(b)(2) Customers, along with all other costs and revenue adjustments not excluded by the Five Assumptions. These costs and revenue adjustments include BPA's administrative and general costs, the FBS allocation of contract revenue deficiencies, and secondary revenue credits.

Prior to comparison with the 7(b)(2) rates from the 7(b)(2) Case, the 7(b) rates from the Program Case will be reduced by the Applicable 7(g) Costs listed in section 7(b)(2). All the costs of BPA conservation programs, billing credits, Experimental Resources, and Uncontrollable Events that were allocated to the 7(b) rates will be subtracted. The reduced Program Case rates will then be compared to the 7(b)(2) rates to determine if the 7(b)(2) rates are lower, on average, than the Program Case rates.

The comparison between the Program Case and the 7(b)(2) Case rates will be conducted for the Five-Year Period and will consider the time value of money. Therefore, the two sets of rates will be discounted back to the first year of the Relevant Rate Case at BPA's projected future nominal borrowing rate, and then a simple average will be computed over the Five-Year Period. The discounted average rates will be rounded to the nearest tenth of a mill per kilowatthour. If the simple average of discounted 7(b)(2) Case rates is less than that of the Program Case rates, then a determination of an amount of rate protection to be reallocated in BPA's rate proposal is required.

VIII. Determination of Rate Protection Amount

If it is determined that the results of the rate test require a reallocation of costs for BPA's rate proposal to effect the rate protection, then the amount to be credited to the 7(b)(2) Customers and reallocated to BPA's other customers must be calculated. This credit reflects the fact that it is a rate period adjustment that is based on a Five-Year Period determination. The difference in average discounted rates will be multiplied by the preference customer loads for the Relevant Rate Case to determine the reduction in the 7(b)(2) Customers' rate period costs.

IX. Conclusion

The section 7(b)(2) rate test, up to and including the point at which the rate protection amount is determined, is conducted outside of the mainstream of BPA's rate development process. While the rate test reflects the Five Assumptions used in the rate proposal, the rate test

has no impact on BPA rates until the rate protection amount is included in BPA's rate design. At this point, any adjustment made to reflect the rate test results in BPA rates must be done within the overall framework of the rate development process and of BPA's ratemaking objectives and statutory requirements. Therefore, the section 7(b)(2) rate test results will be included as a step in BPA's rate design process, consistent with other statutory provisions and BPA's ratemaking objectives.

FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR
2007 SUPPLEMENTAL POWER RATE CASE
SECTION 7(b)(2) RATE TEST

JANUARY 31, 2008

PREPARED BY

PUBLIC FINANCIAL MANAGEMENT

The PFM Group

Public Financial Management, Inc.
PFM Asset Management LLC
PFM Advisors

APPENDIX A TO:

7(b)(2) RATE TEST STUDY, WP-07-E-BPA-50

SECTION 1

PURPOSE OF REPORT

The purpose of this report is to provide our recommended financing costs that will be used by Bonneville Power Administration (“BPA”) as inputs in their calculation of the "reduced public body and cooperative financing costs" as described in Section 7(b)(2)(E) of the Northwest Power Act. We also discuss certain assumptions and rational used in arriving at these recommended financing costs. In providing the enclosed summary of our conclusions and assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets, the activities of BPA and other public and private utilities in the Pacific Northwest (“PNW”) and throughout the country.

SECTION 2

INTRODUCTION

The Northwest Power Act requires that the Administrator of BPA periodically review and revise the rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the rates for firm power to be charged its preference, Direct Service Industry (“DSI”), Investor Owned Utility (“IOU”), and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Northwest Power Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> "the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph, and reserve benefits as a result of the Administrator's actions under this chapter were not achieved."

Section 7(b)(2)(D) specifies the assumptions to be made to meet public body, cooperative, and Federal agency customer (7(b)(2) Customers) loads. After meeting contractual obligations with Federal Base System (“FBS”) resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include: actual and planned resources acquired from 7(b)(2) Customers including conservation programs undertaken or acquired by BPA; existing 7(b)(2) Customer resources not dedicated to regional loads; and generic resources acquired from non-7(b)(2) Customers. .

The quantifiable monetary savings associated with the "reserve benefits" per Section 7(b)(2)(E)(ii) relates to reserves that could be made available to BPA by the nature of BPA's contracts with DSI customers. Prior DSI contracts had provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of the DSI loads. In prior 7(b)(2) rate cases, the DSI loads were assumed to be served by utilities in the Northwest instead of by BPA. The 7(b)(2) rate test also requires the assumption that these utilities would have had to provide their own reserve resources, and that the utilities would finance reserve resources without BPA participation. BPA's analysis of the restriction rights value in its 7(b)(2) rate cases had contained the assumption that the financing costs associated with such reserves would be different were they acquired by regional utilities.

Similar to BPA's 2002 and 2007 Power Rate Cases, BPA's Power Business Line is forecasting a zero purchase of supplemental reserves from the DSIs for FY 2009 in the 2007 Supplemental Power Rate Case. Therefore, the 7(b)(2) Financing Cost Study will not include resource acquisitions by the Joint Operating Agency (JOA) for the replacement of supplemental reserves provided by the DSIs.

This report provides our conclusions concerning financing costs for BPA's public body, cooperative and Federal agency customers to be used in the 7(b)(2) rate case proscribed in the Northwest Power Act. The conclusions presented in this report represent our opinions as financial advisors familiar with the municipal and governmental utility credit markets and with bond issues for both public power agencies and IOUs in the Pacific Northwest. Given the assumptions noted in this report, our conclusions represent the most probable situation, had the hypothetical situation described in the Northwest Power Act occurred.

SECTION 3
EXECUTIVE SUMMARY

This report derives and provides estimates of the interest rates and differentials associated with financing for the different classes of resources identified in Section 7(b)(2) of the Northwest Power Act. Prior 7(b)(2) rate cases have utilized both historic and projected interest rate assumptions for several financing structures. Historic interest rate assumptions have been applied to the financing of prior expenditures for "Named Resources", conservation resources and other forms of generation resources. Projected interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generation

resources. This report also derives and provides estimates of interest rates and differentials associated with the different classes of resources in the Program Case. In the case of certain Named Resources, actual historical financing costs were utilized. Table A contains a summary of historical and projected interest rate assumptions for various resource categories. It is important to note that Table A has been developed from the format provided in prior 7(b)(2) rate study analyses. The prior studies sought to provide historical and prospective interest rates for long-term, fixed-rate financings. As such, the rates provided in the prior studies were for level debt service financing structures with an assumed final maturity of roughly 30 years. In order to estimate the average interest rate for a 30-year financing, prior studies used various interest rate measures for bonds having a term of 25 years. We concur that the selection of interest rate indices having a 25-year term represents a reasonable estimate of the financing costs for 30-year, level debt service borrowings. In Table A, we have again provided interest rate assumptions based on indices and market data for 25-year maturities, along with assumptions for 15-year and 20-year maturities to finance conservation investments. (See Table D further in this report.)

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown in Table A below are derived from historic borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The historic interest rate differentials are a reasonable basis for establishing assumptions for projected interest rate differentials for borrowing costs for the period encompassing BPA's 2007 Supplemental Power Rate Case.

A general observation from the data provided in Table A is, that for most financing categories, the 7(b)(2) Case interest rates are higher than those assumed in the Program Case. When there is a positive number in the “Interest Rate Differential” column, it represents that amount by which the 7(b)(2) Case interest rate is higher (or more costly) than the Program Case.

The interest rate averages listed above in Table A would serve as the assumed interest rates for the Program Case and 7(b)(2) Case for the prospective maturity terms outlined.

TABLE A – Summary of Historical and Projected Interest Rate Assumptions

Resource	Program Case Interest Rate With BPA Backing	7(b)(2) Case Interest Rate Without BPA Backing	Interest Rate Differential Basis Points
Historical Named			
Idaho Falls	N/A	N/A	N/A
Cowlitz Falls (25Yr)	4.20% Actual (1)	4.25%	5
Projected Conservation (2)			
BPA Sponsored (25 Yr) Table C, page 14	4.98%	5.17%	19
Other Public (20 Yr) Table D, page 14	4.91%	5.09%	18
Other Public (15 Yr) Table D, page 14	4.68%	4.85%	17
Projected Generation			
Public (25 Yr) Table C, page 14	4.98%	5.17%	19
Non-7(b)(2) (25 Yr) Table F, page 18	6.51%	5.17%	-134

N/A = Not Applicable.

(1) Actual True Interest Cost of refunding issue sold August 24, 2003.

(2) The interest rates provided for various Projected Conservation categories are assumed for either BPA or JOA borrowings having the maturities so listed. In the 2007 Supplemental Power Rate Case Section 7(b)(2) Study, BPA assumes that conservation measures related to 2001 and prior had a useful life of 20-years, and for years 2002 and after that a useful life of 15-years applies. Those expenditures are assumed to be financed by the JOA over a useful life of 20 and 15 years, depending on the vintage year of the investment. During FYs 2000-2007, BPA issued $142 million in conservation bonds with 3 or 4 year terms. The weighted average term was 3.21 years, with a weighted average interest rate of 4.71%. During the 2007 Supplemental Power Rate Case study period FY 2009 – FY 2013, BPA projects that it will borrow $192 million for conservation investments using five-year maturities with a weighted average interest rate of 5.99%. Since the term of these conservation bonds is not comparable with the longer term maturities that are being projected in the 2007 Supplemental Power Rate Case's 7(b)(2) Rate Test, the rates were not included in the table.

SECTION 4
ASSUMPTIONS

In developing our interest rate assumptions, we have used the types of financing that most likely would be, or could have been, used at the time of funding the hypothetical resources acquired according to the terms of the 7(b)(2) rate test. We have relied upon common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) Customers and non-7(b)(2) Customers, would be assumed to be financed using customary public financing methods for long-term fixed rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large-scale resource acquisition programs similar to what BPA or its customers could have undertaken or would utilize in the future.

As noted above, the Northwest Power Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) Case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted. An assumption has been made in prior 7(b)(2) Financing Cost Studies, with which we concur, that the 7(b)(2) Customers would have formed a Joint Operating Agency ("JOA") where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar, but not identical, legal structure to Energy Northwest and other JOAs such that underlying legal obligations would have been clearly enforceable.

The member agencies of the JOA are listed in Attachment A along with their respective shares. All of the member agencies are assumed to have signed "take-or-pay agreements," such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of debt service, each remaining participant would be responsible for an increased level of debt service of up to 125 percent of the member agency's original commitment. Based on such a typical financing structure, and in concurrence with the assumptions contained in prior 7(b)(2) Financing Cost Studies,, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating in the "A" category from both Moody's and S&P - two well regarded bond rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed that the financing would have received and maintained a rating in the "Aa/AA" from both Moody's and S&P.

In estimating the financing costs for specific Named Resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating. Therefore, the ability of the Public Utility District No. 1 of Lewis County (Lewis County PUD), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we have estimated financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5

ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

In previous rate cases, BPA has assumed the JOA would have undertaken two phases of resource acquisition. The first phase assumed the acquisition of peaking resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) Case. Unlike some prior rate cases, BPA's Power Business Line is forecasting a zero purchase of Supplemental Reserves from the DSIs in the 2007 Supplemental Power Rate Case. Therefore, the current 7(b)(2) study will not include resource acquisitions by the JOA for the replacement of supplemental reserves provided by the DSIs.

The second phase of resource acquisition program assumes the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. In prior years, BPA has acquired resources through its Competitive Resource Acquisition Program, unsolicited proposals, and BPA Billing Credit programs. In recent years, BPA has acquired wind and solar renewable resources along with small hydro and waste heat recovery resources through direct acquisitions. RELEVANCE? WERE THE RESOURCES FINANCED? I just thought this was a more complete description of BPA’s resource acquisition activity. Billing credits were not financed either. The complete description describes resources that are in the 7(b)(2) resource stack whether or not they were financed (if they were not financed, the financing cost differential per Section 7(b)(2)(E)(i) does not apply to those resources.)

The City of Idaho Falls and BPA entered into a replacement Power Purchase Agreement dated September 5, 2006,, for the purchase of all power and energy produced from four hydroelectric generating plants operated by the City of Idaho Falls (the Idaho Falls Project). Lewis County PUD entered into a Power Purchase Agreement dated May 23, 1991, with BPA for the output of the Cowlitz Falls Hydroelectric Project (the Cowlitz Falls Project). BPA has solicited for resources through the BPA Billing Credits Policy contained in section 6(h) of the Northwest Power Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, BPA has contracted for the output of four projects consisting of South Fork Tolt, Wynocchee, Short Mountain Landfill, and Smith Creek. The total output of these four projects totals 20.0 aMW. Under the terms of the BPA Billing Credits Policy, BPA's obligation to purchase the output is subject to the availability of the

resource and, therefore, we do not believe the existence of the BPA power purchase agreement to be material to the credit rating of the financing associated with these particular resources.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be factors that would impact the financing costs of particular resources.

We have assumed that all financings will utilize traditional fixed-rate debt with a level debt service structure. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) Customers or other entities would have comparable features.

Financing of the Cowlitz Falls Project and the Idaho Falls Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis. In the Program Case, BPA would contract to purchase power output. In the 7(b)(2) Case, BPA would contract with the JOA.

In addition, it is assumed that all financings by 7(b)(2) Customers are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that section 9(f) of the Northwest Power Act requires certain certifications by the Administrator prior to the acquisition of resources, which must be met in order that the exemption from gross income in section 103 (a)(l) of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for the purposes of the resource acquisitions contemplated with BPA, that the tax-exemption for financings will not be adversely affected and that BPA will be able to provide the certifications required under the Northwest Power Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of BPA have remained stable in recent years. Uncertain water conditions, the financial requirements of BPA's resource acquisition programs, fish and wildlife issues, and other items are significant issues affecting the PNW and BPA's credit ratings. However, for the purposes of

the 7(b)(2) rate case, no change in credit ratings is projected for BPA, or the 7(b)(2) Customers, as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6

IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho executed a Power Purchase Agreement whereby BPA agreed to a long-term purchase of the output of four hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the four hydroelectric generating plants with the proceeds of revenue bonds issued in 1981. These bonds were subsequently refinanced on multiple occasions. A new five-year Power Purchase Agreement for the period October 1, 2006 through September 30, 2011 was executed on September 5, 2006. This agreement states that it is the intent of the parties to negotiate a successor contract prior to the expiration of the current contract. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the BPA Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate case.

SECTION 7

COWLITZ FALLS PROJECT

On May 23, 1991, Lewis County PUD entered into an Amendatory Contract for Power Purchase (the Contract) whereby BPA agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project (Cowlitz Falls Project). BPA and Lewis County PUD agreed that Lewis County PUD would finance construction of the Project through the issuance of revenue bonds, with BPA agreeing to pay to or on behalf of Lewis County PUD amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis County PUD issued $171,095,000 in Public Utility District No.1 of Lewis County, Washington, Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991. The bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000 and a final maturity of October 1, 2024. The callable bonds of this series were again refunded on August

23, 1993. The remaining 1991 bonds and the callable bonds issued in 1993 were refunded again on June 19, 2003.

Under the terms of the Contract, the primary source of security for the bonds is revenues received from BPA pursuant to the Contract and a Payment Agreement (the Payment Agreement). Under the Contract, BPA is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If BPA does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the bonds is an operating and maintenance (O&M) expense of BPA, having priority over payments of BPA's Treasury debt and repayment of the Federal investment in the Columbia River Power System.

Because the revenues from the Contract and the Payment Agreement secure Lewis County PUD's revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the primary support for the current credit ratings. BPA retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) test, Lewis County PUD is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis County PUD's own load.

The original bonds were priced on Tuesday, August 27, 1991, with a True Interest Cost of 7.10%. The refunding Bonds priced on Tuesday, August 23, 1993 had a True Interest Cost of 5.61%. The refunding Bonds priced on June 19, 2003 had a True Interest Cost of 4.20%. Of the $146,210,000 of bonds sold in 2003, $135,930,000 was guaranteed by municipal bond insurance companies and rated AAA. The uninsured bonds maturing in years 2005 through 2007 were rated Aa2/AA-. As stated earlier, we believe that a bond issued on behalf of the 7(b)(2) Customers would have carried a rating in the A category. During the months preceding the Lewis County sale, there were several bond issues sold for A-rated electric utilities. However, in most every case, these bonds were also guaranteed by a municipal bond insurance policy – and rated AAA. Interest rates on these insured bonds were comparable to those of the Lewis County bonds. In our opinion, the net financing cost differential between AA- and A-rated bonds that were both backed by AAA-rated insurance policies would have been a function of the price charged by the insurance companies. In the case of the Lewis County bonds, one insurance policy for a portion of the bonds was priced at .33% of the total amount of insured

debt service. The other policy applied to a different grouping of bonds was priced at .475% of insured debt service. The amount of these premiums is taken into account in the calculation of the 4.20% True Interest Cost on the bonds. In our opinion, at the time the Lewis County bond sold, an approximate market insurance premium for an A-rated issuer would have been approximately .75% of insured debt service. A recalculation of the Lewis County True Interest Cost with the .75% assumed insurance premium produces a rate of 4.25%. In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers from the BPA backing is approximately equal to the 5 basis point differential between the two True Interest Costs.

SECTION 8

JOA BORROWING COSTS

For purposes of establishing assumptions for JOA borrowing costs, we feel it is appropriate to utilize the historical interest rate assumptions from 7(b)(2) Financing Cost Studies conducted prior to the 2007 Power Rate Case ("Pre-2007 Power Rate Studies"). However, as in the Final 2007 Power Rate Study published in July 2006, we feel that there are more appropriate measures for more recent rates and projected interest rate assumptions. For Pre-2007 Power Rate Financing Cost Studies, 7(b)(2) historical assumptions were based upon an analysis of bond issues for selected public power agencies for the period from January 1, 1982 to March 8, 1999. The analysis compared the True Interest Cost for each financing for each FY to the Bond Buyer 25-Bond Revenue Bond Index (Revenue Bond Index). The Revenue Bond Index consisted of revenue bonds maturing in 30 years. At times, roughly 10 of the 25 bonds included in the index are electric power related financings. In general, the Revenue Bond Index consists of issuers with an average rating equivalent to Moody's "A1" and Standard & Poor's "A+" with a concentration of issuers rated "A1/A +" or "AA/Aa" from at least one rating agency.

The Pre-2007 Power Rate Financing Cost Studies then analyzed the relationship between bonds of different rating categories to the Revenue Bond Index. In this portion of the analysis, it was decided to eliminate Energy Northwest from the list of power revenue bond issuers with at least "AA" from either rating agency in order to assess the effect that the sometimes heavy issuance of refunding revenue bonds by Energy Northwest may have had on the Revenue Bond Index and the various rating categories. For each year prior to FY 1996, the study determined the average percentage represented by: (1) the true interest costs of large public power issues in a given year, divided by: (2) the Revenue Bond Index in place on the sale dates. This calculation was performed for bond issues in the A-rated category and bond issues in the AA-

rated category – excepting Energy Northwest issues. The annual average of the individual issue percentages in each rating class was then multiplied by the average Revenue Bond Index for the entire fiscal year to arrive at an assumption for the average borrowing costs for A-rated and AA-rated issuers during that year.

The 2002 7(b)(2) Rate Study recognized: (1) the diminishing data set of A-rated public power bonds due to the increasing use of AAA bond insurance, and (2) the existence of useful market indices such as the Bloomberg Capital Markets fair value yield curves. The Bloomberg Capital Markets calculates daily indexes for several rating categories and maturity ranges for power revenue bonds. The information appears to be generally consistent with information included from prior years based upon the actual issuance of power revenue bonds by different rated issuers. The Bloomberg yield curves provide data for electric revenue bonds of several credit rating categories, including bonds rated A-, A+, AA- and AA+. In order to estimate rates for bonds in the A and AA rated categories, we took the average of published rates for the A- and A+ categories for the A-rated data, and took the average of published rates for the AA- and AA+ categories for the AA-rated data. Interest rate estimates are for financings with level debt service and a 30-year final maturity. The Bloomberg rates for 25-year maturities were used as the best estimates of financing costs for this financing structure. These averages for FY 2004 and prior fiscal years are found in Table B. Table B provides the following information:

(1) the annual average of the Revenue Bond Index,
(2) the calculated hypothetical AA-rated (and thus BPA-backed) average financing cost,
(3) the calculated hypothetical A-rated (and thus JOA-backed) average financing cost, and
(4) the interest rate differential between #s (3) and (4) for fiscal years prior to 2004.

TABLE B - Historical Interest Rate Assumptions From Prior 7(b)(2) Rate Studies

FY End 9/30	Revenue Bond Index	BPA Rate	JOA Rate	Difference
1982	13.25%	12.65%	13.31%	0.66%
1983	10.13%	9.86%	10.47%	0.61%
1984	10.43%	10.69%	10.74%	0.05%
1985	9.90%	10.35%	10.10%	-0.25%
1986	8.26%	8.49%	8.42%	-0.07%
1987	7.68%	7.77%	7.68%	-0.09%
1988	8.40%	8.50%	8.48%	-0.02%
1989	7.17%	7.01%	7.13%	0.12%
1990	7.51%	7.62%	7.49%	-0.13%
1991	7.20%	6.96%	7.02%	0.06%
1992	6.69%	6.33%	6.35%	0.02%
1993	6.06%	5.73%	5.81%	0.08%
1994	6.08%	5.63%	5.98%	0.35%
1995	6.57%	6.34%	6.51%	0.17%
1996	6.01%	5.80%	5.96%	0.16%
1997	5.87%	5.61%	5.76%	0.15%
1998	5.41%	5.15%	5.31%	0.16%
1999	5.41%	5.14%	5.24%	0.10%
2000	6.07%	5.82%	5.92%	0.10%
2001	5.53%	5.26%	5.42%	0.16%
2002	5.42%	5.10%	5.34%	0.24%
2003	5.15%	4.89%	5.19%	0.30%
2004	5.13%	4.87%	5.10%	0.23%

For more recent years' interest rate assumptions, and for the 2007 Supplemental Power Rate Case that resets FY 2009 rates, we suggest utilizing the same methodology for establishing the estimated rates for A and AA rated electric revenue bonds. We used the database of Bloomberg interest rates for AA-rated and A-rated, 25-year tax-exempt electric revenue bonds as the best proxies for BPA and JOA borrowing costs. We are also of the opinion that the best assumptions for financing costs used in this 2007 Supplemental 7(b)(2) Case are historical interest rates over just the past ten years. We feel this time period will provide a sufficient data set for the 2007 Supplemental Rate Test period of FY 2009-2013. It also eliminates from the data set the period during the early 1980s that was characterized by very high interest rates. We feel that the economic conditions and interest rates of the past ten years have a greater likelihood of being replicated than do the conditions of the early 1980s. For this reason, we have based our future interest rate assumptions for each of the various financing structures on the data from FY 1998 and forward.

Based on the Bloomberg Fair Market yield curves over the past ten fiscal years, the average AA-rated, 25-year electric revenue bond yield was 4.98%. This figure represents a 19 basis point advantage relative to the 5.17% average for the A-rated average for the comparable period. Table C provides these figures for the past ten fiscal years.

TABLE C – Recent Average AA and A Rated, 25-Year Electric Revenue Bonds

FY End 9/30	AA Bloomberg BPA Rate	A Bloomberg JOA Rate	Difference
1998	5.15%	5.31%	0.16%
1999	5.14%	5.24%	0.10%
2000	5.82%	5.92%	0.10%
2001	5.26%	5.42%	0.16%
2002	5.10%	5.34%	0.24%
2003	4.89%	5.19%	0.30%
2004	4.87%	5.10%	0.23%
2005	4.59%	4.85%	0.26%
2006	4.52%	4.70%	0.18%
2007	4.41%	4.60%	0.19%
Averages	4.98%	5.17%	0.19%

For the 2007 Supplemental Power Rate Case Financing Cost Study, we have been advised by BPA personnel of the potential consideration of resource financings that would have repayment periods greater than 30 years. Specifically, there is consideration to potential financing of generation resources that would have terms of 35 years. Our analysis indicates that the average rates listed above of 4.98% and 5.17% would have each been 3 basis points higher for 35-year maturities. We were also advised that the financing terms for conservation investments would be for 15 and 20 year terms, depending on the vintage year of the prior conservation investments made by BPA through its customers. Table D below provides various historical and projected interest rate assumptions for borrowings with final maturities of 15 and 20 years.

TABLE D – Various Term Structure Interest Rate Assumptions

FY End 9/30	Program Case 15-Year	7(b)(2) Case 15-Year	Program Case 20-Year	7(b)(2) Case 20-Year
1998	4.93%	5.03%	5.07%	5.17%
1999	4.93%	5.02%	5.12%	5.22%
2000	5.53%	5.62%	5.79%	5.88%
2001	4.97%	5.12%	5.21%	5.37%
2002	4.78%	5.01%	5.04%	5.27%
2003	4.43%	4.67%	4.79%	5.06%
2004	4.44%	4.63%	4.79%	5.01%
2005	4.20%	4.40%	4.46%	4.72%
2006	4.31%	4.50%	4.45%	4.65%
2007	4.32%	4.49%	4.39%	4.59%
Averages	4.68%	4.85%	4.91%	5.09%

The period averages listed above would serve as the assumed interest rates for the 2007 Supplemental 7(b)(2) Cases' prospective 15 and 20 year financings.

In our opinion, the above-assumed projected borrowing rates are reasonable estimates for borrowing costs of municipal issuers during the 2009-2013 time period. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax -exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

SECTION 9

NON-7(b)(2) CUSTOMER BORROWING COSTS

Private developers, industrial companies, utility subsidiaries, governmental and quasi-governmental entities all represent viable sponsors for developing power projects whose output could be made available to BPA. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive considerable financing benefits from inclusion of a BPA power purchase contract.

For the purposes of this analysis, it is assumed that BPA would enter into an all encompassing power purchase agreement whereby BPA would be obligated to pay an amount sufficient to cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default and remedies upon default are presumed to be resolved in a fashion that enables a project to be financed upon standard commercial terms.

Project sponsors which are private entities may or may not be able to qualify for tax-exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility" such as a waste to energy facility. Projects financed with tax-exempt financing

would likely occur at interest rates comparable to those for the hypothetical JOA discussed in section 8. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80 percent but can be as much as 100 percent, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a BPA contract would provide the means for securing debt financing at pricing which would be at the upper end of the quality range for similar projects. The perceived credit quality of the BPA contract obligation among potential financing sources would increase financing options for a given project.

As in the Final 2007 Power Rate Cases' Financing Cost Study, for purposes of historical non-7(b)(2) resource financing, we again feel it is reasonable to utilize the historical interest rate assumptions contained in the Pre-2007 Rate Studies for the 7(b)(2) Rate Test. Pre-2007 Rate Studies have assumed that private debt financing for a project with a BPA contract could have been arranged at 50 basis points over the lender's cost of funds, which was assumed to have been the six-month's London Interbank Offered Rate (LIBOR), with 100 percent financing of project costs. The prior financing studies then adjusted for the possible effects of entering into interest rate swaps or conversion agreements which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction. In order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, prior financing studies assumed a 50 basis point addition to the LIBOR based interest rates to represent the amortized cost of an interest rate swap. Table E below provides the 18-year history of monthly averages for six-month LIBOR utilized in the Prior 2002 Study, along with the calculated borrowing rates for the same period. Table E also provides the JOA rates utilized in the Prior 2002 Study. The assumptions are the same as those listed and discussed in Section 8.

TABLE E - Historical Interest Rate Assumptions From Pre-2002 7(b)(2) Rate Studies

FY End 9/30	6-Mo. LIBOR	Adjusted Non 7(b)(2) Fixed Rate	JOA Rate	Difference
1982	15.41%	16.41%	13.31%	-3.10%
1983	10.29%	11.29%	10.47%	-0.82%
1984	11.27%	12.27%	10.74%	-1.53%
1985	9.57%	10.57%	10.10%	-0.47%
1986	7.65%	8.65%	8.42%	-0.23%
1987	6.55%	7.55%	7.68%	0.13%
1988	7.67%	8.67%	8.48%	-0.19%
1989	9.38%	10.38%	7.13%	-3.25%
1990	8.27%	9.27%	7.49%	-1.78%
1991	6.85%	7.85%	7.02%	-0.83%
1992	4.22%	5.22%	6.35%	1.13%
1993	3.41%	4.41%	5.81%	1.40%
1994	4.29%	5.29%	5.98%	0.69%
1995	6.25%	7.25%	6.51%	-0.74%
1996	5.37%	6.37%	5.96%	-0.41%
1997	5.53%	6.53%	5.76%	-0.77%
1998	5.74%	6.74%	5.31%	-1.43%

Once again, the greater amounts of historical data and proliferation of market indices allowed us to refine the methodology used in the Pre-2007 Rate Studies. For more recent years' interest rate assumptions, and for the 2007 Supplemental Power Rate Case we suggest utilizing the Bloomberg database of interest rates for AA-rated, 25-year taxable utility bonds as the best proxy for potential non-7(b)(2) project financing costs. We have based our future interest rate assumptions for each of the various financing structures on the data from FY 1998 and forward. Table F below provides the past ten years' averages for the Bloomberg AA-rated, 25-year utility bonds as compared to the JOA financing costs assumed for the same periods. Again, the JOA financing cost assumptions are those provided in Section 8.

TABLE F - Recent Average Bloomberg AA and A Rated, 25-Year Electric Revenue Bonds

FY End 9/30	AA Bloomberg Taxable Utility Non 7(b)(2) Rate	A Bloomberg Tax-Exempt Bond JOA Rate	Difference
1998	6.50%	5.31%	-1.19%
1999	6.67%	5.24%	-1.43%
2000	7.74%	5.92%	-1.82%
2001	7.43%	5.42%	-2.01%
2002	6.85%	5.34%	-1.51%
2003	6.29%	5.19%	-1.10%
2004	6.23%	5.10%	-1.13%
2005	5.67%	4.85%	-0.82%
2006	5.89%	4.70%	-1.19%
2007	5.83%	4.60%	-1.23%
Averages	6.51%	5.17%	-1.34%

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of taxable and tax-exempt borrowers the indicated time periods. Many factors influence the movement of interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

ATTACHMENT A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANT	% SHARE
Eugene Water and Electric Board	3.70
Seattle	13.72
Tacoma	6.66
PUD #1 of Chelan County	2.53
PUD #1 of Cowlitz County	6.35
PUD #1 of Douglas County	.92
PUD #2 of Grant County	4.11
PUD #1 of Snohomish County	9.41
PUD #1 of Clark	6.00
SUBTOTAL - GENERATORS (9)	53.40
Springfield	1.24
PUD #1 of Benton County	2.44
Central Lincoln PUD	1.67
Clatskanie PUD	1.21
Franklin PUD	1.13
PUD #1 of Grays Harbor County	1.73
PUD #1 of Lewis County	1.10
Umatilla Electric Cooperative Association	1.14
SUBTOTAL - NONGENERATORS WITH A GREATER THAN 1% SHARE (8)	11.65
SUBTOTAL - REMAINING NONGENERATORS (100)	34.95
TOTAL (117)	100.00

This page intentionally left blank

This page intentionally left blank