2010 BPA Rate Case
Wholesale Power Rate Final Proposal

SECTION 7(b)(2) RATE TEST STUDY

July 2009

WP-10-FS-BPA-06

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WP-10 SECTION 7(b)(2) RATE TEST STUDY

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power 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
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
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 (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
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
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people’s utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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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 (hereafter called the Rate Test) of the projected amounts to be charged (hereafter called rates) for general requirements power sold to its public body, cooperative, and Federal agency customers, over the rate period (e.g., FY 2010-2011) plus the ensuing four years (hence, FY 2010-2015), with the power costs (hereafter called rates) to such customers for the same time period if certain assumptions are made. The purpose and effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from higher costs resulting from certain 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 rate customers to other BPA power sales. BPA has codified the procedures to conduct the Rate Test in the *Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act Implementation Methodology* (*Implementation Methodology*), WP-07-A-07, which, in turn, relies on BPA's legal interpretation of section 7(b)(2), as set forth in the *Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act Legal Interpretation* (*Legal Interpretation*), WP-07-A-06.

The rate test involves the projection 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 rate period and the ensuing four years prior to the application of section 7(b)(2) (i.e., the "projected amounts to be charged for firm power," known as Program Case rates); and (2) a set for the same period after applying the five assumptions listed in section 7(b)(2) (i.e., the "the power costs for general requirements," known as 7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates (reduced Program Case rates) prior to the rate comparison. Next, each nominal rate is discounted to the beginning of the rate period of the relevant rate case. The discounted reduced Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest hundredth of a mill for comparison. If the simple average of the reduced 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 reduced Program Case rates and the average of the 7(b)(2) Case rates is used to determine the amount of costs to be reallocated from the 7(b)(2) Customers to other BPA power sales for the rate period.

1.1 Purpose and Organization of Study

The purpose of this Study is to describe the application of the *Implementation Methodology* and the results of such application. The accompanying Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-10-FS-BPA-06A, contains the documentation of the computer models and data used to perform the 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 *Legal Interpretation* and the *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 describes the forecast of exchanging utilities' average system costs (ASCs). The fourth section presents a summary of the results of the rate test for the WP-10 Final Proposal. There are two attachments to the Study. Attachment 1 is the current *Legal Interpretation*. Attachment 2 is the current *Implementation Methodology*, with proposed changes shown in red-line markup. There are seven appendices to the Study and Documentation. Appendix A, Financing Analysis, provides documentation for the financing benefit assumptions. Appendix B, 7(b)(2) Resource Stack, provides an example of the resource stack, GDP inflator/deflator tables, and documentation in support of the accounting and financing treatment of the expensed portion of conservation resource costs. Appendix C, Non-Conservation Resources, provides documentation for the amount and costs of non-conservation resources in the resource stack. Appendix D, Conservation Resources, provides documentation for the amount and cost of conservation resources in the resource stack. Appendices E, F, and G provide additional information regarding the ASC forecasts for FY 2010-2015: Appendix E presents summary tables; Appendix F presents forecast costs, load, and ASCs; and Appendix G presents forecast purchase power and sales for resale.

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) (*1984 Legal Interpretation*). The *1984 Legal Interpretation* was revised as part of the WP-07 Supplemental rate proceeding. A short summary of the *Legal Interpretation*, WP-07-A-06, follows.

- 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 those assumptions on the ratemaking processes, which otherwise 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 excluded from the Program Case and the 7(b)(2) Case rates before those rates are compared. Applicable 7(g) Costs are excluded from the Program

Case rates by an explicit subtraction. Applicable 7(g) Costs are excluded from the 7(b)(2) Case rates by not being included in the 7(b)(2) Case revenue requirement.

- “Within or Adjacent” DSI Loads are assumed to be served by 7(b)(2) Customers for the entire rate test period.
- “Within or Adjacent” DSI Loads assumed to be served by 7(b)(2) Customers are assumed to be served wholly with firm power.
- 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 of BPA service to the DSIs or a change of situation in local service area or electrical connection. (Appendix B has been modified to reflect that Port Townsend Paper is now “Within or Adjacent.”)
- 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 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 section 7(b)(2) implementation issues. The section 7(i) hearing was held as the first phase of the 1985 general rate proceeding. The issues resolved in the hearing are set forth in the *Administrator’s Record of Decision for Section 7(b)(2) Implementation Methodology* (7(b)(2) ROD), b2-84-F-02, published in August 1984, and are reflected in the adopted *Section 7(b)(2)*

Implementation Methodology (*1984 Implementation Methodology*), *id*. Appendix C. The *1984 Implementation Methodology* was revised as part of the WP-07 Supplemental rate proceeding and adopted in the *2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision* (*2007 Supplemental ROD*), WP-07-A-05. The major issues resolved in the *1984 Implementation Methodology*, b2-84-F-02, as modified in the *2008 Implementation Methodology*, WP-07-A-07, 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 the assumption that "Within or Adjacent" DSI Loads may be less than the total amount of DSI Loads served by BPA. The *Implementation Methodology* allows for reserves from sources other than DSIs subject to the criteria listed therein.

- Financing benefits in the 7(b)(2) Case are quantified for planned or existing Type 1 resources (*see* explanation of resource "types" in section 2.1.2.2) that have been acquired by BPA or are planned to be acquired in the Program Case during the Rate Test period. Financing benefits for existing Type 1 non-conservation resources that received a financing benefit associated with having a BPA acquisition contract when constructed and originally financed are separately identified for these "Named Resources." The financing benefits in the 7(b)(2) Case are prepared by BPA's financial advisor for the 7(b)(2) rate test, Public Financial Management, which estimates the resource sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did not acquire the resource output. The current financing study (Appendix A) and past financing studies have made the simplifying assumption that a Joint Operating Agency (sponsor of the resource(s)) would be formed to undertake the resource acquisitions for the 7(b)(2) Customers, with membership consisting of the region's 7(b)(2) Customers. The composition of the membership and the credit ratings of the individual members are contained in Attachment A to Appendix A, the financing study. It is assumed that BPA would contract with the JOA in the 7(b)(2) Case to provide the additional resources assumed in the 7(b)(2) Case. 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.

- Non-conservation Type 1 and Type 2 resources that are already constructed and financed and that did not receive any financing benefit associated with having a BPA acquisition contract when constructed do not have their financing costs changed by the financing study. Financing costs in the 7(b)(2) Case are quantified for planned or existing Type 2 resources that are owned or purchased by 7(b)(2) Customers but are not committed to load pursuant to section 5(b) of the Northwest Power Act. When ownership of a resource is by non-preference customers, or is unidentifiable (Type 3 resources), the *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 and revenue from marketed secondary energy.

- The rate test in this rate case is conducted using a single automated Excel® spreadsheet called RAM2010. The outputs of this spreadsheet model are in the Documentation, WP-10-FS-BPA-06A, Section 2. The sequence of steps used to conduct the Rate Test is outlined below in Section 2.1.

- The projected rates for each of the six years are discounted back to the beginning of the rate proposal test period using factors based on BPA's projected borrowing rate for each year. The discounted rates then are averaged for each Case and the result rounded to the nearest hundredth 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-hundredth of a mill or more. If the Rate Test triggers, the difference between the two rates is multiplied by the projected energy billing determinants of PF Preference customers in the rate period to determine the amount of costs to be reallocated from PF Preference customers to all other power sales.

2. METHODOLOGY

Implementing the rate test consists of incorporating the determinations from the *Legal Interpretation* and *Implementation Methodology* into the RAM2010 model.

2.1 Sequence of Steps

The rate design steps of RAM2010 carry out BPA's ratemaking process by performing the steps needed to develop wholesale power rates that are used as the Program Case for the rate test. The 7(b)(2) Case steps of RAM2010 carry out BPA's ratemaking process with changes to reflect the five 7(b)(2) assumptions.

2.1.1 Program Case in RAM2010

RAM2010 calculates annual Program Case rates for the WP-10 rate period (FY 2010-2011) and the following four years, FY 2012-2015. The method of calculating rates and the data used to calculate rates for the Program Case are identical to those used in calculating the actual proposed rates for the two-year rate period. For the following four years, the Program Case uses the same method of calculating rates as for the rate period and uses data that is consistent with data used for the rate period.

2.1.1.1 Sales

The sales forecast used to develop rates for the Program Case covers the period FY 2010-2015 and is the same forecast as is used to develop BPA's proposed rates. Sales forecasts are developed for the region's consumer-owned utilities (COUs) by aggregating utility-specific forecasts for those customers. The forecast Residential Exchange Program (REP) retail loads are provided by the utilities and verified by BPA's load forecasters. *See* Loads and Resources

Study, WP-10-FS-BPA-01, section 2.2.6. For purposes of the rate test, this Study is forecasting the sale of a limited amount of power to the DSIs under the Industrial Firm Power (IP) rate schedule. Sales to Federal agencies and other contractual sales are entered into RAM2010.

BPA's total sales obligations are comprised of COU, investor-owned utility (IOU), DSI, Federal agency, REP, and Firm Power Products and Services (FPS) contractual sales. All PF, IP, and New Resource Firm Power (NR) forecast sales are entered into RAM2010 with diurnally and monthly differentiated energy and monthly differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the Loads and Resources Study, WP-10-FS-BPA-01, Section 2.2, and Documentation, WP-10-FS-BPA-01A, Section 2.3, Tables 2.3.1 and 2.3.2, and the WPRDS Documentation, WP-10-FS-BPA-05A, Section 2.

2.1.1.2 Load-Resource Balance

RAM2010 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 Loads and Resources Study, WP-10-FS-BPA-01, Section 2.4. Data from the Loads and Resources Study are used to calculate the energy allocation factors (EAFs) to ensure that costs of resources are allocated to loads in the order prescribed by the Northwest Power Act. The costs of FBS resources are first allocated to the PF rate pool (consisting of COU, Federal agency, and REP loads) until FBS resources are exhausted. Exchange resources then are used to serve any remaining PF loads in the PF rate pool. 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. A more complete explanation of this process is contained in the WPRDS, WP-10-FS-BPA-05, Chapter 3.

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 and minimum required 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; decommissioning costs of the Trojan nuclear plant; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. Exchange resource costs are based on the ASCs of utilities participating in the REP, including cost adjustments if there are deeming utilities. New resource costs are those of the Federal 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. *See* Revenue Requirement Study, WP-10-FS-BPA-02.

2.1.1.4 Cost Allocation

Allocation of projected costs to rate pools is performed on an average annual energy basis in RAM2010. Generation costs for each year are allocated by the use of EAFs calculated using the results of the Loads and Resources Study, WP-10-FS-BPA-01, Section 2.2. Conservation and billing credit costs, BPA's administrative and general expenses, and energy service business costs are allocated across all BPA firm loads pursuant to section 7(g) of the Northwest Power Act. The cost allocation procedures for the Program Case are those used to develop BPA's proposed rates, as explained in the WPRDS, WP-10-FS-BPA-05, Chapter 3.

2.1.1.5 Rate Design

The adjustments made to allocated costs in RAM2010 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-10-FS-BPA-05, Chapter 3.

Secondary and Other Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 70 water years for secondary energy generation capability. Secondary revenues are credited to loads served by FBS and new resources pursuant to Northwest Power Act section 7(g). RAM2010 uses the secondary energy sales revenue forecast produced by RiskMod, as documented in the WPRDS Documentation, WP-10-FS-BPA-05A, Section 2, Table 2.5.3, for FY 2010-2011, and the Risk Analysis and Mitigation Study Documentation, WP-10-FS-BPA-04A, Section 2.4.1.5, for FY 2012-2015.

The Surplus Firm Power Revenue Surplus/Deficiency results when available surplus firm power is sold at other than its fully allocated cost. Included in this study are long-term contracts that can convert between exchange or power-sale mode depending on the circumstances of the individual contracts and BPA's load-resource balance. The WP-10 Final 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 such power after adjusting for transmission costs, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to other firm loads served by FBS and new resources pursuant to Northwest Power Act section 7(g). The revenues from capacity sales are included in the determination of the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources pursuant to section 7(g).

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 (*see* WPRDS, Section 2.2.1). The net margin is negative 0.164 mills/kWh in nominal dollars. Generally, costs are reallocated, pursuant to section 7(g), from the IP rate pool to other rate pools so that the applicable DSI rate equals the applicable wholesale rate to 7(b)(2) Customers plus the net margin.

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 the 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 rate pools, pursuant to section 7(g).

2.1.2 7(b)(2) Case in RAM2010

The 7(b)(2) Case section of RAM2010 calculates 7(b)(2) Case rates the same way as Program Case rates, except where the *Implementation Methodology* sets forth specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales

The sales forecasts input to RAM2010 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 test year of FY 2015. Programmatic conservation resources with amortized lifetimes that end before FY 2015 are assumed to be obsolete, have been removed from the 7(b)(2)(D) resource stack, and have no effect on the 7(b)(2) Case 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 and have no effect on the 7(b)(2) sales forecast.

2.1.2.2 Resources

The size of the FBS is identical for the Program Case and the 7(b)(2) Case. However, RAM2010 currently displays the size of the FBS in such a way that the FBS that is available to serve requirements load is shown as being 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 during any year of the test period in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the *2008 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 owned or purchased by 7(b)(2) Customers that are not committed to load pursuant to section 5(b) of the Northwest Power Act. These first two types of resources include any BPA programmatic conservation resources 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 the *Legal Interpretation*, the portions of the Mid-Columbia hydro resources that are contracted to regional IOUs and that serve regional loads are committed to load pursuant to section 5(b) for purposes of the rate test. In addition, portions of the Mid-Columbia hydro resources that are contracted to regional COUs and the portion of these resources that are sold at auction are deemed to be committed to regional loads pursuant to section 5(b) unless it is demonstrated that such resources are being exported outside of the PNW.

2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act is prepared by BPA's financial advisor, Public Financial Management. The financial advisor's financing study is Appendix A to this Study. It shows that the proposed financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities, using 15-year term financing, is 20 basis points. Thus, financing costs in the Program Case are 20 basis points lower than the 7(b)(2) Case. For the Cowlitz Falls Project (a "Named Resource"), the proposed benefit of BPA's participation is 5 basis points, based on an assumed revenue bond issued with and without a BPA contract for the Project. This increases the financing costs for additional resources, and thus the power costs, of the 7(b)(2) Customers in the 7(b)(2) Case.

2.1.2.4 Load-Resource Balance

The 7(b)(2) Case section of RAM2010 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 augmentation purchase power, is 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 included in the 7(b)(2) Case as Type 1 resources. The 7(b)(2) Customer loads are larger than the Program Case PF Preference loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred, and "Within and Adjacent" DSI Loads are added to 7(b)(2) Customer loads. The larger 7(b)(2) Customer loads in the 7(b)(2) Case can result in the need to select additional resources from the 7(b)(2)(D) resource stack (*see* Appendix D of the Documentation).

2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case contains the same costs as in the Program Case, with certain modifications as specified by the *Implementation Methodology*. The 7(b)(2) Case excludes Program Case revenue requirement amounts for conservation and energy efficiency, billing credits, new resources, and exchange resources. The only Applicable 7(g) Costs in the Program Case revenue requirement are costs of conservation and energy efficiency and billing credits. By removing these costs from the final 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 subtracted from the Program Case just prior to the rates for the two Cases being compared. This is discussed further in section 3.3 below. In addition, the contract sales of FBS resources excluded from the 7(b)(2) Case (contracts not existing on the effective date of the Act) provide no revenue credits. Repayment studies are performed for each year of the rate test period using the same procedures as the Program Case but without excluded resource costs. The final 7(b)(2) Case revenue requirement documentation can be found at WP-10-FS-BPA-02B, Chapter 6. The 7(b)(2) Case revenue requirement includes the annual debt service amounts associated with the deferral of expensed conservation costs and the annual debt service associated with capitalized conservation costs that are chosen from the 7(b)(2) resource stack. Documentation of annual amounts (aMW) of conservation savings available to serve the 7(b)(2) Customer loads that are included in the resource stack and the related costs associated with these savings are shown in Appendix D of the Documentation. The 7(b)(2) Case revenue requirement also includes the operating expenses and financing costs of non-conservation resources that are selected from the 7(b)(2) resource stack. The documentation for the amount (aMW) of these non-conservation resources and their related costs is provided in Appendix C of the Documentation.

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 explicitly added into the 7(b)(2) Case rates, because these historical and projected costs are contained in the cost of conservation resources included in the 7(b)(2) resource stack.

3. UTILITY ASC FORECASTS FOR FY 2010-2015

To perform the rate test, ASCs for utilities participating in the REP must be included for the rate period (FY 2010-2011) and forecast for the following four years (FY 2012-2015). This section describes the forecasting of utility ASCs for the rate test.

3.1 Average System Cost Calculation

An ASC is calculated by dividing a utility's total Contract System Cost (generation and transmission costs as determined in the ASC Review Process) by its total Contract System Load (total retail load adjusted for distribution losses less New Large Single Loads). The resulting quotient is the utility's ASC. Whether a cost or load may be considered in the ASC calculation is determined pursuant to a methodology developed by BPA in consultation with regional parties. The most recent version of this methodology is the 2008 ASC Methodology (2008 ASCM). ASCs are not determined in BPA's rate cases; they are calculated in ASC Review Processes, which are separate administrative proceedings. For more information about the 2008 ASCM and the ASC Review Processes, *see* http://www.bpa.gov/corporate/finance/ascm/.

3.2 FY 2010-2015 ASC Calculation

3.2.1 Methodology for Forecasting ASCs

ASCs are calculated in two steps under the 2008 ASC Methodology. The ASC calculation begins with a determination of a "Base Year ASC" for the utility. The Base Year ASC is an ASC based on the data from the utility's most recent FERC Form 1 (or equivalent) at the time the utility submits its ASC filing to BPA. For this rate period, the Base Year is CY 2007. In the ASC Review Process, BPA evaluates the appropriateness of the utility's costs and loads in the Base Year ASC for conformance with the 2008 ASCM.

Once the Base Year ASC has been established, the next step is for the utility's ASC data to be adjusted for the temporal differences between the base year and the rate period. The costs and revenues included in the utility's Base Year ASC are escalated (escalation may be negative) from the end of the Base Year (December 31, 2007) to the mid-point of BPA's rate period, which in this case is October 1, 2010. This escalation is accomplished using factors identified in the 2008 ASCM. The ASC that results after this final step is the utility's "Exchange Period ASC," which is referred to in this Study as the "rate period ASC." The rate period ASC changes during BPA's rate period only to reflect new resource additions or reductions that were submitted during the ASC Review Process and allowed in the utility's final ASC report.

The costs and loads used to calculate ASCs for FY 2010-2011 are then escalated for the remainder of the rate test period (FY 2012-2015) to forecast ASCs for the rate test. The discussion of ASCs in this Study focuses on the remainder of the rate test period, FY 2012-2015. However, certain background information on the determination of the rate period ASCs is provided herein for clarity. *See* http://www.bpa.gov/corporate/finance/ascm/ for additional details.

3.3 2010-2011 Rate Period ASCs

As noted in the WPRDS, section 6.0, the ASC Review Processes were completed concurrent with the final WP-10 rate determinations. Official notice is taken of the results of the ASC Review Process, and the results are incorporated into the rate case. A summary of the Final ASC Reports for FY 2010-2011 is presented in the WPRDS, WP-10-FS-BPA-05, Table 6.1. For more information about the FY 2010-2011 ASCs, *see* WPRDS, WP-10-FS-BPA-05, section 6.0.

3.4 ASC Forecast for FY 2012-2015

ASCs for FY 2012-2015 are forecast using a methodology that is similar to the 2008 ASCM used to determine ASCs for FY 2010-2011. The rate period ASCs are used as the starting point for forecasting the FY 2012-2015 ASCs and are adjusted to include the costs of all new resources forecast to come on-line through the end of the rate period. Next, the rate period costs are escalated to the midpoint of each fiscal year through FY 2015, using the same ASC methodology and escalators that are used to determine the rate period ASCs. This escalation uses the same forecasts of inflation rates, natural gas prices, and market prices as are used to forecast BPA costs and revenues. The escalators are shown in Appendix E, Table 5, of the Documentation, WP-10-FS-BPA-06A. The results of the ASC forecast for each year of the rate test period are shown in Appendix F, Tables A-H, of the Documentation.

The FY 2012-2015 ASC forecast assumes that all load growth is met with market purchases at utility-specific market rates. The utility-specific market rates are calculated using the individual utilities' price spreads contained in each utility's ASC filing. The Contract System Loads used in the FY 2012-2015 ASC forecast are shown in Appendix E, Table 2, of the Documentation.

Forecasts of ASCs for FY 2012-2015 are calculated for all utilities that filed ASCs with BPA in October of 2008. The filing utilities are Avista Utilities, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Franklin County PUD, and Snohomish County PUD. Appendix E, Table 3, of the Documentation summarizes the FY 2012-2015 ASC forecasts for these utilities.

Changes made to the rate period ASCs as a result of BPA's final determinations in the ASC Review Process have been reflected in the WP-10 Final Proposal ASC forecasts for FY 2012-2015. These changes include adjustments to the forecasts of inflation, natural gas prices, and market prices. In addition, the utilities' ASC filings were corrected, as necessary, for errors found during the formal ASC Review Process.

3.5 Exchange Load Forecast for FY 2012-2015

Exchange load is defined as the sum of a utility's residential and small farm loads as determined by the terms of each utility's Residential Purchase and Sales Agreement (RPSA). Forecast exchange loads are used to determine the amount of exchange resources included in the Program Case. Applying each utility's ASC to utility's exchange load determines the cost of exchange resources.

Utilities intending to participate in the REP for FY 2010-2011 were required to submit with their ASC filings a forecast of their exchange load, measured at the retail meter, for FY 2010-2015. These exchange load forecasts are used for both the rate period (FY 2010-2011) and the remaining years of the rate test period (FY 2012-2015). The exchange load forecasts used in this Study are increased to reflect the distribution losses submitted by the utilities with their initial ASC filings in October of 2008.

Participating utilities' retail load forecasts are summarized for both the rate period, FY 2010-2011, and the remaining years of the rate test period, FY 2012-2015, in the Loads and Resources Study Documentation, WP-10-FS-BPA-01A, Section 2.2, Table 2.2.8. Exchange load forecasts for FY 2012-2015 are summarized in Appendix E, Table 4, of the Documentation, WP-10-FS-BPA-06A.

Appendix E, Tables 1-4, of the Documentation summarize each utility's Contract System Cost, Contract System Load, ASC, and Residential and Small Farm Exchange Load, respectively, for FY 2011-2015. Appendix F shows the calculations of each utility's forecast Contract System

Cost, Contract System Load, and ASC. Appendix G shows additional details on the calculation of each utility's Purchase Power expense and Sales for Resale revenue.

4. SUMMARY OF RESULTS

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

4.1 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-10-FS-BPA-05, Section 3. Table 1 below shows the projection of undiscounted nominal Program Case rates.

4.2 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 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.

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

RAM2010 performs the 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 allocated to the rates 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 the 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 are 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 2010 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's forecast borrowing rates that are used in the discounting procedure and the corresponding cumulative discount factors. When applied to the rates in the two Cases, the simple averages of the two discounted rates over the rate test period are calculated, rounded to two decimal places, and compared. As shown in Table 4, the rate test triggers by 8.17 mills/kWh. Therefore, an adjustment to the WP-10 PF Preference rate, valued at about $1,003.4 million (*see* WPRDS Documentation, Section 2, Table 2.5.9) is required.

Table 1
Program Case Rates

(Nominal mills/kWh)

A	B	C	D
Fiscal Year	Rate	Applicable 7(g) Costs	Net Rate
2010	35.27	1.52	33.75
2011	37.37	1.56	35.81
2012	38.01	1.50	36.51
2013	39.54	1.56	37.98
2014	38.82	1.56	37.26
2015	40.26	1.51	38.75

Table 2
7(b)(2) Case Rates

(Nominal mills/kWh)

A	B
Fiscal Year	7(b)(2) Rate
2010	23.79
2011	26.07
2012	25.46
2013	28.16
2014	26.88
2015	28.09

Table 3
Discount Factors for the Rate Test

A	B	C
Fiscal Year	Annual BPA Borrowing Rate[1]	Cumulative Discount Factor[2]
2010	.0623	.9413
2011	.0703	.8794
2012	.0736	.8191
2013	.0729	.7634
2014	.0704	.7132
2015	.0689	.6672

[1] Revenue Requirement Study Documentation, WP-10-FS-BPA-02B, Chapter 6.
[2] $DiscFact_t = DiscFact_{t-1}/(1 + BorrowRate_t)$; Fiscal Year 2009 equals 1.

Table 4
Comparison of Rates for Test
(Discounted mills/kWh)

A	B	C
Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2010	31.77	22.39
2011	31.49	22.93
2012	29.91	20.85
2013	28.99	21.50
2014	26.57	19.17
2015	25.85	18.74
Average Rate	29.10	20.93

Difference of Average Rates 8.17 mills/kWh

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SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

LEGAL INTERPRETATION

September 2008

WP-07-A-06

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DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

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

I. Background

A. Relevant Statutory Provisions

The Administrator of the Bonneville Power Administration (BPA) is charged with the responsibility of implementing section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839, *et seq*. 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 responsible for establishing rates pursuant to 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 over a reasonable number of years. 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. <u>Relevant Rate Case</u>: 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. <u>General Requirements</u>: 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. <u>7(b)(2) Customers</u>: 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. <u>Applicable 7(g) Costs</u>: 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 (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 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 (1) resources designated by BPA as providing reserves, or (2) 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 start up 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 identified two secondary effects of the Five Assumptions found in section 7(b)(2) in its 1984 Legal Interpretation that continue to be relevant. 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. Any additional secondary effects will be identified by BPA in the relevant rate case.

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) and the secondary effects. 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 longstanding 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.

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 "projected amounts to be charged" when calculating the costs of the Program Case. Because the two clauses are identical in all material respects, the same power costs that were used to serve the "general requirements" in the Program Case should be used as the starting point to construct the revenue requirement for the 7(b)(2) Case; that is, "the projected amounts to be charged for firm power, subject to the Five Assumptions and their secondary effects."

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 revenue requirements in the Program Case and the 7(b)(2) Case ensures that the later application of the Five Assumptions and their secondary effects 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 determining the power costs in the 7(b)(2) Case. 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 and their secondary effects. 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 and their secondary effects.

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, exclusive of costs related to the Five Assumptions and their secondary effects, 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, *infra*.

Section 7(b)(2)(D) provides that, in conducting the 7(b)(2) test, the Administrator is to assume that:

> 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, *infra*. 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). The term "such resources" refers to resources sufficient to meet the Administrator's contractual obligations under section 5 to provide electric power to meet firm power loads. 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 starting 7(b)(2) Case revenue requirements. 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). This is also consistent with the lack of "exclusive of" language after the reference in section 7(b)(2) to "power costs for general requirements of such customers …" 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, exclusive of costs related to the Five Assumptions and their secondary effects. That is, the costs of resources associated with the Applicable 7(g) Costs will be excluded from the 7(b)(2) Case power costs through application of the Five Assumptions. The Applicable 7(g) Costs will be excluded from the Program Case rates prior to comparison with the 7(b)(2) Case rates. 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" are 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 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), forecast 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 speaks directly to an issue and 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 clear and 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 territories 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, section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with the FBS resources, and section 7(b)(2)(D) requires that additional resources be assumed to serve the remaining 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 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 resource cost allocation 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 resource cost allocation 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' Remaining 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. This 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 meet 7(b)(2) Customer load to the extent it is needed and it is among the least expensive resources available. *See* Issue 3, *supra*.

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. "The cost of resources to meet these requirements are … (b) 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., 58 (1979), Appendix B.

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 resources designated by BPA to provide reserves and BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, 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.

SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

IMPLEMENTATION METHODOLOGY

February 2009

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Attachment 2

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DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Electric 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 (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 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 (1) resources designated by BPA as providing reserves, or (2) 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 start up 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 revenue requirements and the 7(b)(2) Case revenue requirements prior to further determination of the 7(b)(2) Case power costs.

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' remaining 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. Conservation is a Type 1 resource. 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 costs allocated to, and all loads included in, the 7(b) load pool, without respect to the tiering of such loads and related costs.

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 and their secondary effects 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 because conservation is a non-FBS resource. In addition, 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 meet 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

Section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with FBS resources, and 7(b)(2)(D) requires that additional resources be assumed to serve the remaining general requirements of the 7(b)(2) Customers. As in the Program Case, the FBS in the 7(b)(2) 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).

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 loads 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 committed 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 resources 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 and their secondary effects, 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, for example, 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. Non-conservation Type 1 and Type 2 resources that are already financed and constructed and that did not receive any financing benefit associated with having a BPA acquisition contract when originally constructed or when refinanced do not have their financing costs changed by the financing study.

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 designated resources or restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, 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 designated resources or 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 resources or 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 and their secondary effects. These costs and revenue adjustments include, but are not limited to, 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 beginning of 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 hundredth 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 non-PF Preference sales 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. Although the rate test reflects the Five Assumptions and their secondary effects 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.

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FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR
2010 POWER RATE CASE
SECTION 7(b)(2) RATE TEST

June 3, 2009

PREPARED BY

PUBLIC FINANCIAL MANAGEMENT

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PFM Asset Management LLC
PFM Advisors

APPENDIX A TO:

7(b)(2) RATE TEST STUDY, WP-10-FS-BPA-06

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 rationales 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 and 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 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" described in Section 7(b)(2)(E)(ii) relate to reserves that could be made available to BPA by the nature of BPA's contracts with its customers. In the WP-10 Final Proposal, Power Services is assuming a small amount of DSI load (estimated to be 402 aMW), with firm power deliveries sold at the Industrial Firm Power (IP) rate determined in the rate case. Power Services has informed PFM that it is hopeful that it will be able to negotiate contracts that will allow it to sell firm power to DSI loads for FY 2010-2011. Although prior DSI contracts have provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of DSI loads, Power Services informs us that the future DSI contracts' provisions to restrict or interrupt the load is uncertain. The Final Proposal assumes a value on this interruptibility of $0.80/MWh. As in prior rate cases where BPA has served DSI loads with firm power in the Program Case, DSI loads are assumed to be served by utilities in the Northwest instead of BPA in the 7(b)(2) Case. The 7(b)(2) rate test requires the assumption that these utilities would purchase the reserves or provide their own reserve resources. If the reserve resources were acquired instead of purchased the utilities would finance reserve resources without BPA participation. In prior rate cases, BPA's analysis of the restriction rights value for the 7(b)(2) rate test has contained the assumption that financing costs associated with such reserves would be different if they were acquired by regional utilities. Since the anticipated DSI service is small in relation to past historical loads, the assumption has been made in the 7(b)(2) Case that the JOA and its member utilities would purchase required reserve power amounts. Because it is assumed that reserve power requirements will be purchased in the 7(b)(2) Case, the 7(b)(2) rate test 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 estimated financing costs for BPA's public body, cooperative, and Federal agency customers to be used in the 7(b)(2) rate test described 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 a 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 tests have utilized both actual historical interest rates and projected future interest rate assumptions for several financing structures. Historical interest rate assumptions have been applied to the financing of prior expenditures for "Named Resources," conservation resources, and other forms of generating resources. Projected future interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generating 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 5-year, 10-year, 15-year, and 20-year maturities to finance conservation investments. (*See* Tables C through G in this report.)

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown in Table A below are derived from historical borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The historical interest rate differentials have been used as a reasonable basis for establishing assumptions for projected interest rate differentials for borrowing costs for the WP-10 rate period. It is important to note that the interest rate assumptions in Table A for Projected Conservation and Projected Generation expenditures are derived from historical interest rate averages over the past three years (5/16/2006-5/15/2009). Prior to the WP-07 Supplemental Section 7(b)(2) Rate Test Study, the interest rate assumptions were developed by averaging data over a 10-year period preceding the relevant Section 7(b)(2) Rate Test Study.

Over the past 18 months, credit market conditions exhibited a degree of volatility and uncertainty that has not been experienced in several decades. Conditions over the last three months have been more stable and it would appear that credit markets may be settling into a new "normal." One clear impact of the current market environment is that interest rate differentials between various credit ratings are more pronounced than they have been in many decades. Until September 2008, the impact of recent credit market volatility had not been as pronounced in the governmental utility market sector examined by this report, as compared to lesser credit ratings. However, the

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 Resources			
Idaho Falls	Not Applicable	Not Applicable	Not Applicable
Cowlitz Falls (25Yr)	4.20% Actual (1)	4.25%	5
Projected Conservation – see notes (2) and (3)			
BPA Sponsored (25 Yr) Table C, page 14	4.68%	4.91%	23
BPA Sponsored (20 Yr) Table D, page 15	4.62%	4.84%	22
BPA Sponsored (15 Yr) Table E, page 15	4.48%	4.68%	20
BPA Sponsored (10 Yr) Table F, page 15	4.07%	4.29%	22
BPA Sponsored (5 Yr) Table G, page 15	3.45%	3.69%	24
Projected Generation			
Public (25 Yr) Table C, page 14	4.68%	4.91%	23
Non-7(b)(2) (25 Yr) Table H, page 18	6.10%	4.91%	-119

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

(2) The interest rates provided for various Projected Conservation investments are assumed for either BPA or JOA borrowings having the maturities so listed. In the WP-10 Section 7(b)(2) Rate Test Study, BPA assumes that conservation capitalized measures related to fiscal years 2001 through 2015 would be amortized and financed by a JOA over a period of 15 years. Conservation first-year expensed costs would be deferred and amortized and financed over a 5-year time period. During FYs 2006-2009 (year to date), BPA issued $65 million in conservation bonds with 3 to 5 year terms. The weighted average term was 3.8 years, with a weighted average interest rate of 4.60%.

(3) During the 2010 Power Rate Case study period FY 2010 – FY 2015, BPA projects that it will borrow $262 million for conservation investments using 5-year maturities with a weighted average interest rate of 5.32%. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table.

The mid-to-high investment grade, tax-exempt, municipal utility market sector has recently seen pronounced interest rate spread differentials between credit rating categories. In September and October of 2008, there were several weeks when the global credit markets, including the municipal bond market, were essentially closed to borrowers. Since that time, investment grade governmental utilities have had access to the market, albeit at interest rates and credit spreads that approach the highest levels in roughly 20 years. The new and evolving nature of these market conditions presents a considerable challenge to the task of developing reasonable estimates to be used in the WP-10 rate case.

Given that:

1 - an important product of this report is the assumed interest rate differential between the Program Case Interest Rates and the 7(b)(2) Case Interest Rates,

2 - the interest rate differential between the two Cases is derived entirely by exploring historical interest rate data for various credit rating categories, and

3 - that current, and perhaps future market conditions are markedly different from conditions over the past ten years,

PFM is of the opinion that it would be inappropriate to develop assumptions for the upcoming six-year section 7(b)(2) rate test period by utilizing the past practice of averaging data from the prior 10-year period. Therefore, PFM recommends revising the prior practice of using the most recent 10 years of interest rate data and instead utilizing the most recent three years of data as a reasonable assumption for the purpose of the current rate test study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent three-year period will reflect the likelihood that some degree of market disruption could persist for at least a portion of the period covered by the current rate test study, and that the six-year nature of the rate test period leaves a considerable amount of time for the markets to continue to evolve in reaching a new equilibrium in interest rates and credit spreads.
As in prior rate test studies, 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. The Program Case rate in Table A assumes that BPA purchased conservation resources from customers using customer-issued tax exempt bonds. However, the Program Case revenue requirement assumes that conservation financing is done with bonds issued through the U.S. Treasury, see Notes 2 and 3 to Table A above. 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 rate in 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.

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 assumed JOA are listed in Attachment A along with their respective shares and credit ratings. 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 JOA 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“ category from both Moody's and S&P. BPA’s current ratings are Aaa from Moody’s and AA- from S&P. In PFM’s opinion, the “Aa/AA” rating category represents a ratings category that contains the midrange of the divergent Moody’s and S&P ratings. We utilize this assumption because there are interest rate databases for various rating categories, but there are no databases for “split” ratings in those cases where there is a difference between the Moody’s and S&P rating categories.

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. As outlined in the introduction, Supplemental Reserves for the 7(b)(2) Case are provided by market purchases. 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.

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 as provided by 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 is approximately 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 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 test, 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. On September 5, 2006, the City of Idaho Falls and BPA executed a new five-year Power Purchase Agreement for the period October 1, 2006, through September 30, 2011. 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. BPA and Lewis County PUD agreed that Lewis County PUD would finance construction of the Cowlitz Falls 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 revenue received from BPA pursuant to the Contract and a 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, along with the payment of operating and maintenance (O&M) expenses of the project, have 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) rate 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 percent. The refunding Bonds priced on Tuesday, August 23, 1993, had a True Interest Cost of 5.61 percent. The refunding Bonds priced on June 19, 2003, had a True Interest Cost of 4.20 percent. 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 0.33 percent of the total amount of insured debt service. The other policy, applied to a different grouping of bonds, was priced at 0.475 percent of insured debt service. The amount of these premiums is taken into account in the calculation of the 4.20 percent True Interest Cost on the bonds. In our opinion, at the time the Lewis County bonds sold, an approximate market insurance premium for an A-rated issuer would have been approximately 0.75 percent of insured debt service. A recalculation of the Lewis County True Interest Cost with the 0.75 percent assumed insurance premium produces a rate of 4.25 percent. 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, it is appropriate to utilize a historical interest rate methodology, as was the case with 7(b)(2) financing cost studies conducted prior to the WP-07 and WP-07 Supplemental Power rate cases. For pre-WP-07 financing cost studies, 7(b)(2) historical assumptions were based upon an analysis of actual bond issues for selected public power agencies for the period from January 1, 1982, to March 8, 1999.

The 2002 Section 7(b)(2) Rate Test 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 calculated 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 (3) and (4) above for fiscal years prior to 2004.

In October of 2008, Bloomberg Capital Markets discontinued publishing yield curves for electric revenue bonds rated, A-, A+, AA-, and AA+, which were used to calculate the assumed BPA-backed and JOA-backed financing costs in the previous rate case studies. Bloomberg Capital Markets produces several alternative yield curves which include comparable electric revenue bonds of the same maturity and rating used in the prior rate case studies. After conducting analysis to verify significant correlation to the discontinued yield curves on a historical basis, it is PFM's opinion that the use of the Bloomberg Power Revenue Curves, made up of electric revenue bonds for large issuers rated A and AA, will be an acceptable proxy for the WP-10-7(b)(2) Case.

For more recent years' interest rate assumptions, and for the WP-10 Initial Proposal for FY 2010-2011, we suggest utilizing a similar 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 described above, as proxies for BPA and JOA borrowing costs. However, PFM suggests a departure from the prior practice of developing the assumptions for financing costs that utilized historical interest rates over the most recent 10 years in the 2007 Power Rate Case and prior studies. As discussed on pages 5 and 6 of this report, volatility in the credit markets calls for a change in how PFM would develop reasonable assumptions to be used in the WP-10 7(b)(2) Case. As was the case with our Final Financing Study for the WP-07 Supplemental Final Proposal, PFM recommends revising the prior practice of using the most recent 10 years of interest rate data, and instead utilizing the most recent 3 years of data as a reasonable assumption for the purpose of the financing analysis for the Section 7(b)(2) Rate Test Study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent 3-year period will reflect the likelihood that some degree of market disruption could persist for at least a portion of the period covered by the current rate test study. For this reason, we have based our future interest rate assumptions for each of the various financing structures on the data from May 16, 2006 through May 15, 2009.

For the current financing cost study, we have been advised by BPA personnel that the financing terms for conservation investments would be for a 15-year term for the capitalized portion of each year's investment. The first-year expensed conservation costs will be treated as deferred charges (SFAS #71) and financed over a 5-year time period as in the WP-10 Final Proposal. Tables D, E, F, and G below provide various historical and projected interest rate assumptions for borrowings with final maturities of 20, 15, 10, and 5 years.

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

Historical Average AA and A Rated, 25-Year Electric Revenue Bonds

FY 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%
2005	4.92%	4.68%	4.91%	0.23%
2006	5.13%	4.51%	4.69%	0.18%

Based on the Bloomberg Fair Market yield curves over the past three years, the average AA-rated, 25-year electric revenue bond yield was 4.68 percent. This figure represents a 23 basis point advantage relative to the 4.91 percent average for the A-rated average for the comparable period. Table C provides these figures for the past three fiscal years.

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

Year End 5/15	Program Case AA Bloomberg BPA Rate	7(b)(2) Case A Bloomberg JOA Rate	Difference
2007	4.35%	4.49%	0.14%
2008	4.58%	4.77%	0.19%
2009	5.11%	5.47%	0.36%
Averages	4.68%	4.91%	0.23%

TABLE D – 20-Year Term Structure Interest Rate Assumptions

Year End 5/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2007	4.32%	4.47%	0.15%
2008	4.55%	4.75%	0.20%
2009	4.98%	5.30%	0.32%
Averages	4.62%	4.84%	0.22%

TABLE E – 15-Year Term Structure Interest Rate Assumptions

Year End 5/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2007	4.22%	4.35%	0.13%
2008	4.42%	4.59%	0.17%
2009	4.79%	5.09%	0.30%
Averages	4.48%	4.68%	0.20%

TABLE F – 10-Year Term Structure Interest Rate Assumptions

Year End 5/15	Program Case 'AA' Bloomberg BPA Rate	7(b)(2) Case 'A' Bloomberg JOA Rate	Difference
2007	3.99%	4.13%	0.14%
2008	4.04%	4.24%	0.20%
2009	4.17%	4.50%	0.33%
Averages	4.07%	4.29%	0.22%

TABLE G – 5-Year Term Structure Interest Rate Assumptions

Year End 5/15	Program Case BPA Rate - /1	7(b)(2) Case A Bloomberg JOA Rate	Difference
2007	3.76%	3.87%	0.11%
2008	3.50%	3.71%	0.21%
2009	3.09%	3.49%	0.40%
Averages	3.45%	3.69%	0.24%

Note 1 - During the WP-10 rate test period, FY 2010-FY 2015, BPA projects that it will borrow $262 million for conservation investments using five-year maturities with a weighted average interest rate of 5.32%. The bonds will be issued through the U.S. Treasury, so they are not comparable to the tax exempt rates included in the table.

The period averages listed above would serve as the assumed interest rates for the WP-10 7(b)(2) rate test prospective 20, 15, 10, and 5-year financings. To determine the rates for bonds issued with maturities between 5 and 10 years, it would be reasonable to interpolate the rates between the 5- and 10-year maturities. For example the rate for 6-year maturities would represent the 5-year maturity plus 1/5th of the difference between 5 and 10-year maturities.

In our opinion, the above-assumed projected borrowing rates are reasonable estimates for borrowing costs of municipal issuers during the 2010-2015 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, and 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 that 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 high leverage levels and financing at pricing that 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.

Pre-2007 7(b)(2) rate test studies 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. These pre-2007 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.

Once again, the greater amounts of historical data and proliferation of market indices allowed us to refine the methodology from that used in the pre-2007 rate test studies. For more recent years' interest rate assumptions, and for the WP-10 Initial Proposal, 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. As previously described, we have based our future interest rate assumptions for each of the various financing structures on the recent three-year data set from May 16, 2006, to May 15, 2009. Table H below provides the past three years' averages for the Bloomberg AA-rated, 25-year taxable 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 H - Recent Average Bloomberg Taxable AA and Tax-Exempt A Rated, 25-Year Electric Revenue Bonds

Year End 5/15	AA Bloomberg Taxable Utility Non 7(b)(2) Rate	7(b)(2) Case A Bloomberg JOA Rate	Difference
2007	5.86%	4.49%	-1.37%
2008	6.00%	4.77%	-1.23%
2009	6.44%	5.47%	-0.97%
Averages	6.10%	4.91%	-1.19%

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of taxable and tax-exempt borrowers during 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 (JOA)

PARTICIPANTS	AVERAGE FINANCIAL RATING[1]	% SHARE[2]
Generators:		
Eugene Water and Electric Board	A	3.41%
Seattle	A	12.12
Tacoma	A	6.24
PUD #1 of Chelan County	AA	4.12
PUD #1 of Clark	A	5.58
PUD #1 of Cowlitz County	A	6.45
PUD #1 of Douglas County	AA	0.78
PUD # 2 of Grant County	AA	5.92
PUD #1 of Pend Oreille County	BBB	1.20
PUD #1 of Snohomish County	AA	8.48
SUBTOTAL – GENERATORS (10)	A	54.29%
Non-Generators:		
Central Lincoln County PUD	A	1.61
Clallam County PUD #1	A	1.03
Clatskanie PUD	BBB	1.30
Flathead Electric Coop	NR	1.92
Franklin PUD	A	1.18
Inland Power & Light	NR	1.12
City of McMinnville	A	1.11
City of Richland	A	1.03
Springfield	A	1.05
Umatilla Electric Cooperative Association	NR	1.25
Wells Rural Electric Cooperative	NR	1.06
PUD #1 of Benton County	A	2.06
PUD #1 OF Grays Harbor County	A	1.45
PUD #1 of Lewis County	A	1.53%
SUBTOTAL – NONGENERATORS WITH GREATER THAN 1% SHARE (14)	A	18.70%
SUBTOTAL – REMAINING NONGENERATORS (113)	NA	27.01%
TOTAL (117)	A	100.00%

Note 1 – Rating represents the average of the latest reports issued by Standard and Poor's, Moody's, and Fitch rating agencies as of November 2008. The average rating is calculated by assigning a score, 1 to 10, with 1 being a 'AAA' and 10 being a 'BBB-", to the top ten rating categories for each agency and then taking the average score for each issuer. The average score was then assigned a rating of either 'AAA', 'AA', 'A', or 'BBB' based on the range with which it fell. NR designation stands for "not rated."

Note 2 – Percentage shares of participation in the JOA are based on the projected utility Total Retail Loads in relation to total regional Consumer Owned Utility loads.