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

Supplemental Proposal
2007 Wholesale Power Rate Case

SUPPLEMENTAL TESTIMONY, STUDY, AND WITNESS QUALIFICATION

REACTIVE POWER

February 2006

WP-07-E-BPA-28
WP-07-E-BPA-29
WP-07-Q-BPA-54

Supplemental Proposal
2007 Wholesale Power Rate Case

SUPPLEMENTAL TESTIMONY

REACTIVE POWER

February 2006

WP-07-E-BPA-28

INDEX

SUPPLEMENTAL TESTIMONY OF

SARAH K. BERMEJO, REBECCA M. BERDAHL, THOMAS R. MURPHY,
DAVID L. GILMAN, AND TERRIN PEARSON

WP-07-E-BPA-28

Witnesses for Bonneville Power Administration

SUBJECT: INSIDE THE BAND COMPENSATION FOR GENERATION SUPPLIED REACTIVE AND VOLTAGE CONTROL

SUPPLEMENTAL TESTIMONY

SARAH K. BERMEJO, REBECCA M. BERDAHL, THOMAS R. MURPHY,
DAVID L. GILMAN, AND TERRIN L. PEARSON

Witnesses for Bonneville Power Administration

SUBJECT: INSIDE THE BAND COMPENSATION FOR GENERATION SUPPLIED REACTIVE AND VOLTAGE CONTROL

Section 1. Introduction

Q. Please state your name and qualifications.

A. My name is Sarah K. Bermejo. My qualifications are contained in WP-07-Q-BPA-03.

A. My name is Rebecca M. Berdahl. My qualifications are contained in WP-07-Q-BPA-02.

A. My name is Thomas R. Murphy. My qualifications are contained in WP-07-Q-BPA-42.

A. My name is David L. Gilman. My qualifications are contained in WP-07-Q-BPA-13.

A. My name is Terrin L. Pearson. My qualifications are contained in WP-07-Q-BPA-54.

Q. Have you previously submitted testimony in this WP-07 rate case?

A. Yes. In the initial proposal, and this supplemental testimony is meant to modify that initial proposal.

Q. What is the Purpose of your testimony?

A. The purpose of this testimony is to propose to remove the inside the band cost associated with the AEP methodology for FYs 2008 and 2009 from the generation cost allocation for Generation Supplied Reactive (GSR) described in the initial proposal. *See* WP-07-E-BPA-20. This supplemental testimony describes the policy consideration for proposing this change, the rate impacts associated with the change, and outlines possible future rate treatment for generation supplied reactive. This testimony also supports the reactive supplemental documentation, WP-07-E-BPA-29.

Q. How is your testimony organized?

A. Our testimony contains four sections including this first introductory section. The second section describes the proposed change and addresses the policy considerations that lead to this supplemental proposal, the third section evaluates the rate implications of the proposed change, and the fourth section discusses the additional process that TBL will engage in to evaluate the possible future rate treatment for GSR.

Section 2. Proposed Changes to Initial Proposal

Q. What was the initial proposal for generation input cost of GSR?

A. BPA initially forecasted annual revenues of $24.9 million for generation inputs associated with GSR for the rate period. One component of this total was based on the AEP methodology, which allocates a portion of the embedded cost of generation plant to GSR. The AEP methodology is commonly used by generators to determine compensation for inside the band operations of GSR. Applying the AEP methodology resulted in a cost allocation of $18 million for US Army Corp of Engineers (COE) and Bureau of Reclamation (BOR) facilities, and $179,000 for Columbia Generating Station (CGS). The initial proposal also allocated $2.15 million to TBL for real power losses associated with GSR. In addition the initial proposal included $364,000 for synchronous condenser plant modifications and $4.1 million for energy consumed by synchronous condensing. *See* WP-07-E-BPA-20 at 2-10.

Q. How has FERC explained inside and outside the band?

A. Inside the band refers to generation operations to produce reactive power, measured in MVARs, inside a band. Individual generators have a set range of operations in which they can produce a certain amount of MVARs without significantly diminishing MW production. This range is determined by the generators’ design, as indicated by its nameplate power factor rating. When the generator is operated inside of this range it is operating inside the band, and if the generator is requested to produce more MVARs by reducing its real power production, it is operating outside the band.

Q. Does the AEP methodology include payments for inside the band?

A. The AEP methodology allocates a portion of the generation plant to GSR service without regard to, or consideration of, inside or outside the band. It is reasonable to conclude that this methodology includes payments for operations inside the band. BPA hopes to develop a methodology for determining payment for outside the band in a future rate case.

Q. What is the proposed change to the initial proposal?

A. BPA is proposing to eliminate inside the band cost and real power losses from the generation inputs cost allocation for GSR to TBL for FYs 2008 and 2009. This would result in reducing the $24.9 million allocated to generation inputs for GSR by $20.4 million in each of the latter two years of the rate period to $4.464 million for each of those 2 years. The full $24.9 million would remain for FY 2007.

Q. How are you proposing to account for synchronous condensing costs?

A. The $4.464 million of plant modification cost and energy consumed by synchronous condensing would continue to be allocated to generation inputs for GSR in FYs 2008 and 2009.

Q. Why are costs associated with synchronous condensing excluded from this change?

A. As described in BPA's initial proposal, synchronous condensing requires the generator to be operated as a motor to provide voltage support to the transmission system when the generator would otherwise be turned off. These operations consume real power from the system. *See* WP-07-E-BPA-20 at pages 8-9. BPA does not consider synchronous condensing as inside or outside the band operation and it is not part of the AEP methodology.

Q. Why are you proposing to eliminate inside the band cost from the initial proposal?

A. In Order 2003-A, FERC stated that generators should not be compensated for inside the band operation, unless the transmission provider is compensating its affiliate for inside the band operations. Beginning in 2004, several non-affiliate generators interconnected to BPA's transmission system filed rates with FERC to enable the non-affiliate generators to charge TBL for GSR inside the band, based on the AEP methodology. The costs paid to non-affiliate generators are combined with the costs allocated from PBL as inputs into TBL's ancillary service rate for GSR. As more non-affiliate generators have filed for an inside the band rate, TBL's ancillary service rate has increased. This rate is paid by all TBL transmission customers, including PBL and its preference customers. At some point the benefits to regional rate payers of PBL being compensated for an inside the band GSR allocation is outweighed by the cost all transmission customers would have to pay for compensating non-affiliate generators for these higher ancillary service rates.

Q. Are there other concerns with inside the band compensation?

A. Yes. Inside the band payments are determined using the AEP methodology, which allocates a portion of the generator's electrical plant associated with reactive power production to the GSR rate. *See* WP-07-E-20 at pages 4-8. This results in an embedded cost methodology that should treat all generators equally. A problem with this methodology is that it does not take into account the value or amount of reactive support the generator is providing to the transmission system. Instead, the methodology is based simply on the depreciated or net plant cost of the generator. This has resulted in an anomaly, where new peaking generators that may only operate occasionally and provide little reactive support to the transmission system, receive significant compensation, while older generators that are necessary to support the reactive needs of the transmission system may receive little or no compensation. Currently, in the Pacific Northwest generators are being compensated based on this methodology, but others are not being compensated at all. It is hard to see how this varying treatment represents an equitable solution. Another problem with the AEP methodology is that it requires individual FERC filings for each non-affiliate generator. These filings are expensive and difficult for BPA to staff. This creates uncertainty for BPA and its customers, because we never know when the next filing will occur.

Q. Are you aware of any guidance from FERC regarding inside the band reactive payments to non-affiliate generators?

A. Yes. As described above in Order 2003-A, FERC stated that transmission providers are only required to pay non-affiliate generators for inside the band GSR if the transmission provider is compensating its affiliate for inside the band. In a more recent opinion, issued just prior to BPA's initial proposal in this rate case, FERC granted a declaratory order to Entergy recognizing that by foregoing revenues from its own generators' operations inside the band, Entergy would not be obligated to compensate unaffiliated generators for this service. *See* Entergy Service, Inc., 113 FERC ¶ 61,040 at p.24 (2005).

Q. What are the concerns of BPA as a whole that are driving this proposal to change the initial proposal?

A. BPA is concerned that TBL is at risk of incurring uncertain and potential high costs to compensate many additional generators for GSR inside the band. BPA anticipates that generators currently receiving compensation will file for increases in reactive payment after the current TBL settlement with certain non-affiliate generators expires. This could create a significant impact on the total cost of delivered power for all rate payers. Allocating GSR costs for inside the band to TBL has benefited PBL preference customer power rates, but that benefit has declined significantly as more non-affiliate generators have filed rates to charge TBL for GSR inside the band increasing power preference customer transmission rates. BPA is also interested in compensating generators that provide valuable GSR to the system through an outside the band methodology.

Q. Why is this change being proposed in the PBL rate case instead of the TBL rate case?

A. In the WP-02 Rate Case and in this WP-07 rate case, PBL has priced all the generation inputs for ancillary services and TBL uses these cost allocations to establish its ancillary service rates in their transmission rate case. The change proposed in this supplemental testimony is consistent with that practice. TBL will be using the outcome of this rate case, as well as other factors, when it establishes its ancillary services rates for FY 2008 and 2009.

Q. What effect would this proposed change have on various regional stakeholders?

A. As described in Section 2, Table 1 of WP-07-E-BPA-29, the affect on the cost of delivered power will be different for different customer groups. For PF customers, there is a slight rate increase for delivered power at the current level of compensation to non-affiliate generators. However, if TBL payments to non-affiliate generators increase in the future, as expected, this proposal will ultimately result in a benefit to PF customers. In addition, any payments PBL may receive for outside the band GSR would also offset costs to the preference customers. IOUs and other transmission only customers will realize a significant benefit from this proposal, because it will lead to a lower ancillary service rate. If TBL is successful in the necessary FERC filings, non-affiliate generators could be exposed to a significant loss in revenues they currently receive under their FERC approved rates for GSR inside the band.

Q. Please explain why this proposed change will potentially benefit preference customers?

A. Preference customers pay for GSR through TBL's ancillary service rate and PBL pays this same rate when it purchases transmission for surplus sales. When the only cost allocated to TBL's ancillary services rate were inputs from federal generation, preference customers were receiving the benefit of lower delivered power rates because the cost of GSR was spread to all transmission customers. Once TBL had to start paying non-affiliate generators for GSR, TBL's ancillary service rate increased and there was no associated benefit in preference customer's power rates. The proposed change is the first necessary step to eliminating this upward pressure on the ancillary service rate.

Q. This proposed change is only for FYs 2008 and 2009. How are costs for GSR proposed to be treated in FY 2007?

A. For FY 2007, BPA is proposing to treat cost allocation of GSR consistent with the initial proposal, including compensation for inside the band operations based on the AEP methodology.

Q. Why is the change in methodology proposed to take effect one-year into the rate period?

A. BPA is proposing the change for FYs 2008 and 2009, because TBL has committed to pay certain non-affiliate generators that have filed rates with FERC for GRS inside the band until September 30, 2007. This commitment was made in a FERC approved settlement agreement, and neither BPA nor the non-affiliate generators can request a rate change from FERC until the end of FY 2007. BPA's objective is to enable TBL to avoid paying generators for GSR inside the band, and it hopes to accomplish this on the same date for all generators. Therefore, it is reasonable to propose changing the PBL cost allocation at the same time that TBL hopes to end its obligation to pay the non-affiliate generators.

Q. In the initial proposal, it was explained that GSR is an important service used by TBL *to maintain reliability. Please explain why you are now proposing that federal generators should not be compensated for GSR inside the band?*

A. BPA still believes that generators providing GSR is an important service, but BPA has calculated that compensating generators for inside the band under the AEP methodology is not a benefit to regional rate payers. FERC has stated that generators do not need to be compensated for inside the band operations, and these operations can be a requirement of all generators in order to be interconnected to the grid reliably. FERC has also stated that all generators should be compensated when the transmission provider requests that they operate outside of the band. BPA has not yet developed a methodology for compensating generators for outside the band operations, but BPA is hopeful that an outside the band methodology can be developed that compensates generators based on the actual cost the generator incur to supply outside the band reactive to the transmission system.

Section 3. Rate Impacts of Proposed Change

Q. How would this proposal be incorporated into the final rate studies?

A. The final rate studies for the WP-07 rate case will make appropriate adjustments to reflect reduced revenues from inside the band generation supplied reactive and voltage control that reduces the revenue credit used to set the final firm power energy rate and slice rate over the rate period consistent with the Administrator’s decision based on the supplemental record developed on this issue.

Q. What impacts will this proposal have on the PF rate?

A. Although this proposal will not take effect until FY08, the base PF rate is proposed to be set based on assumptions over the three-year rate period. Thus, this proposal will slightly increase the base PF rate by approximately 0.18 mills that will be spread proportionally to the firm power energy rate and slice rate. *See* Section 3, Table 1 WP-07-E-BPA-29.

Q. Are there any other rates that would be impacted by the proposed change?

A. Yes. The proposed change will have a slight impact on per unit generation input costs for Operating Reserves and Regulating Reserves. The net power revenue requirement specific to each of these per unit costs reflects a revenue offset equal to the total annual costs of generation inputs to provide reactive power and voltage control to TBL. This revenue offset will be reduced, which increases the revenue requirement that establishes the total costs to be recovered for provision of Operating Reserves and Regulating Reserves service. The net impact is an increase to the per-unit generation input costs for Operating Reserves and Regulating Reserves, respectively.

Q. What are the impacts to the Operating Reserves and Regulating Reserves generation input cost?

A. Operating Reserves per unit costs will increase by approximately $0.17 kw-month and Regulating Reserves will increase by about $0.19 kw-month. These per unit costs will then be multiplied by an unchanged quantity of PBL supplied generation inputs estimated to be 420 and 150 annual hourly average megawatts respectively, for Operating Reserves and Regulating Reserves, which will yield higher annual revenue forecasts of approximately $900,000 and $360,000, respectively.

Q. Are there any other risks associated with the proposed change?

A. Yes. If the expected value of revenues received from TBL associated with provision of reactive and voltage control service is not recovered due to FERC rejection of an outside the band reactive compensation or for some other unanticipated reason, then a small revenue under-recovery problem will arise. If this occurs, BPA expects to make any appropriate adjustments in subsequent rate cases, wherever appropriate. For this rate period, BPA will reflect in the planned net revenue for risk an expected range of $4 million to $20 million annual of estimated outside the band reactive payments for FYs 2008 and 2009 each.

Q. Why is the expected risk proposed to be modeled at $4 million to $20 million?

A. BPA is proposing to continue to allocate the cost of synchronous condensing to TBL in FYs 2008 and 2009 and this represents the floor amount of $4 million. BPA is hopeful that an outside the band methodology can be developed for FYs 2008 and 2009. PBL believes the $4 to $20 million is a conservative estimate of what total compensation might be under an outside the band methodology, but it is not meant as a cap or limitation for future rate proceedings.

Section 4. Future of Generation Supplied Reactive

Q. How will the proposed change affect TBL's ancillary service rate for generation supplied reactive and voltage control?

A. In the 2006 transmission rate case, TBL developed formula rates to reflect, among other things, changes in PBL generation input allocations established in the 2007 power rate case. The TBL will use the results of the 2007 power rate case, when it sets transmission and ancillary service rates for FY 2008-2009.

Q. What additional steps will TBL need to take to eliminate inside the band payments to non-affiliate generators?

A. TBL is bound by the FERC approved settlement agreement to pay certain non-affiliate generators through the end of FY 2007. Depending on the outcome of this WP-07 rate proceeding, TBL would have to file with FERC and request that the non-affiliate generators' rate schedules be suspended beginning in FY 2008, reflecting the fact that TBL will no longer be compensating its affiliate for GSR inside the band.

Q. Do you anticipate any further rate development regarding generation supplied reactive in the future?

A. Yes. The FERC Staff Report dated February 4, 2005, on "Principles for Efficient and Reliable Reactive Power Supply and Consumption" suggests that pricing principles and regulatory policy are evolving. BPA expects that any such change in FERC policy on reactive compensation, for either inside or outside the band, will be considered in upcoming rate cases and will inform BPA policy on GSR compensation. Additionally, BPA expects to pay close attention to all legal activity surrounding this matter that may help inform internal policy on rate treatment. BPA will be investigating appropriate rate methodologies for compensating generators for outside the band operations.

Q. *Is there any FERC precedent to support an outside the band methodology?*

A. Yes. FERC has stated that generators are entitled to compensation when a transmission provider requests the generator to operate outside the band to supply or absorb reactive power, but FERC has only accepted an outside the band methodology for the New York Independent System Operator. However, recently FERC has indicated that opportunity costs and marginal costs are reasonable methods to consider for outside the band compensation.

Q. *What is the anticipated timing for developing an outside the band rate methodology?*

A. BPA hopes to have an outside the band rate methodology developed to include in the upcoming transmission rate case for FY 2008 and 2009.

Q. *In Section 3 of this testimony you described a range of risk for FYs 2008 and 2009 as $4 to $20 million. Would this range act as a limit on the amount that could be collected under an outside the band methodology?*

A. No, the rate treatment for outside the band GSR is an issue for a future BPA rate case. The reasoning behind the $4 to $20 million range is to reflect potential revenue and an expected range of risk around that revenue, including synchronous condensing costs, to set power rates.

Q. *On pages 6 and 7 of your initial proposal testimony, WP-07-E-BPA-20, you described the power factor used in the AEP methodology and explained why BPA was* *proposing to use the 0.95 power factor. Would this same power factor be used for an outside the band methodology?*

A. Not necessarily. BPA believes it is premature to make any assumptions regarding an outside the band methodology and will look to FERC for guidance as well as how the system is planned and operated to determine an appropriate methodology.

Q. Does this conclude your testimony?

A. Yes

Supplemental Proposal
2007 Wholesale Power Rate Case

SUPPLEMENTAL STUDY

REACTIVE POWER

February 2006

WP-07-E-BPA-29

SUPPLEMENTAL STUDY

REACTIVE POWER

TABLE OF CONTENTS

Page

ACRONYMS

ACRONYM	Definition
AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
Btu	British Thermal Unit
C&R	Cost and Revenue
C&R Discount	Conservation and Renewables Discount
California PX	California Power Exchange
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
EPP	Environmentally Preferred Power
F&O	Financial and Operating Reports
FBS	Federal Base System

FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth Northwest Conservation and Electric Power Plan
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
FY	Fiscal Year (Oct-Sep)
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
GTRSPs	General Rate Schedule Provisions
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLH	Heavy Load Hour
HNF	Hourly Non-Firm
IJC	International Joint Commission
IOUs	Investor-Owned Utilities
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IP	Industrial Firm Power (rate)
ISC	Investment Service Coverage
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
L/R Balance	Load/Resource Balance
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatthour
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOP	Minimum Operating Pool

MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OY	Operating Year (Aug-Jul)
PA	Public Agency
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PSW	Pacific Southwest
PTP	Point to Point
PUD	Public or People's Utility District
PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)
Reclamation	Bureau of Reclamation
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)

RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase Sale Agreement
SCCT	Single-Cycle Combustion Turbine
SS	Share-the-Savings Energy (rate)
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TPP	Treasury Payment Probability
TRL	Total Retail Load
UDC	Utility Distribution Company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
WY	Watt-Year

1. INTRODUCTION

The purpose of this study is to describe the reasons for the proposed changes needed to remove the inside the band cost allocation associated with the AEP methodology for FYs 2008 and 2009 from the generation cost allocation for Generation Supplied Reactive and Voltage Control (GSR). *See* WP-07-E-BPA-28. This study contains three sections including this first introductory section. The second section provides a table and description of the potential impacts the proposed policy change should have on the various regional stakeholders and the third section outlines possible future rate treatments for GSR based on planned net revenues for risk.

2. REGIONAL STATKEHOLDER IMPACTS

Table 1 illustrates the effect this proposed change would have on various regional stakeholders' cost of delivered power. The table represents the distribution of costs and benefits of the proposed policy eliminating GSR payments inside-the-band. More specifically, Line #1 of the table identifies the inside the band compensation paid by TBL to PBL. The actual compensation in 2005 through 2006 is $23 million annually. Based on BPA's initial testimony, this annual payment would be $20.4 million in FYs 2007 through 2009. Lines # 2 and #3 identify the current and projected payments to non-affiliated generators. The annual value of $7.6 million in 2006 (Column B) is based on non-affiliate generator GSR filings that have been accepted for filing by FERC. The values in Column C are based on an assumption that the existing non-affiliate generators will file to increase their GSR rates to $11.2 million when the TBL Settlement expires in FY07, but that no additional non-affiliate generators will file GSR rates with FERC. Column D assumes that additional non-affiliate generators will propose GSR filings totaling $4.6 million and IOU generators will also propose GSR filings totaling $9.2 million. Lines #4 through #7 identify the net cost of BPA GSR policy by customer group. Net cost is defined as total compensation for GSR (if any), less costs paid for GSR through TBL GSR rate. Column A shows the actual distribution of costs and benefits in 2005 when all the net benefits accrued to Preference Customers. In 2006 (Column B), Preference Customer benefits have declined and non-federal generators began receiving a net benefit. Net costs to DSI/IOU and extra-regional customers will increase over 2005. With the expected increase in GSR payments by 2008 (Column D), all customer groups will incur net costs except for the Marketers/non-federal generators. Column E reflects the expected result of the proposed policy to stop compensating all generators for GSR service inside the band and indicates that all customer groups will benefit except for the unaffiliated generators. *See* Section 2, WP-07-E-BPA-28.

Table 1

COSTS OF CURRENT AND PROPOSED REACTIVE PAYMENT POLICY ON CUSTOMER GROUPS

		A	B	C	D	E
				$ Millions		
		2005 ACTUAL	2006 EXPECTED	2008 EXPECTED WITH CURRENT NON-FEDERAL GENERATORS	2008 ESTIMATE WITH ADDITIONAL NON-FEDERAL GENERATORS	ESTIMATED IMPACT OF PROPOSAL
1	TBL compensation to PBL for reactive "within the band"	$ 23	$ 23	$ 21.0	$ 21.0	$ (21.0)
2	Payments to non-affiliated Generators	$ -	$ 7.6	$ 13.0	$ 17.6	$ (17.6)
3	Payments to IOU Generators	$ -	$ -	$ -	$ 9.2	$ (9.2)
	Net Cost By Customer Group 1/					
4	Preference Customers	$ (10.3)	$ (6.1)	$ (2.2)	$ 5.4	$ (5.4)
5	IOU/DSI	$ 5.4	$ 7.1	$ 7.9	$ 1.9	$ (1.9)
6	Extra-regional customer	$ 2.5	$ 3.4	$ 3.7	$ 5.2	$ (5.2)
7	Marketers/non-federal generators	$ 2.4	$ (4.4)	$ (9.4)	$ (12.6)	$ 12.6
						$ -
8	**Net Cost to Regional Ratepayers (Line A + Line B)**	**$ (4.9)**	**$ 1.1**	**$ 5.7**	**$ 7.3**	**$ (7.3)**

1/ GSR compensation less incremental increase in cost of GSR transmission purchases

3. REACTIVE REVNUE RISK ANALYSIS

Table 2 below illustrates the planned net revenue for risk model output from an expected range of $4 million to $20 million of revenues received over the entire power rate period. These are estimates for the purpose of proposing to set final power rates. *See* Section 3 WP-07-E-BPA-28.

Table 2

	Initial Proposal	Proposed Policy Change	Difference
Avg. Annual PNRR	$97 million	$108 million	$11 million
3-Year Avg. Rate	30.34 mills	30.52 mills	0.18 mills
Annual Avg Rates			
FY 2007	32.22 mills	32.45 mills	0.23 mills
FY 2008	30.52 mills	30.64 mills	0.12 mills
FY 2009	28.29 mills	28.48 mills	0.19 mills

1. **For this analysis, we assumed that it was equally likely that annual revenues from TBL could be any value between $4 and $20 million for FY 2008-9.**

2. **As the table shows, this increases the annual PNRR by an average of $11 million, with a corresponding average annual rate increase of 0.18 mills/kwh. The rate effect is largest in FY 2007.**

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

Supplemental Proposal
2007 Wholesale Power Rate Case

WITNESS QUALIFICATION

February 2006

WP-07-Q-BPA-54

QUALIFICATION STATEMENT OF

TERRIN L. PEARSON

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Terrin L. Pearson. I am employed by the Bonneville Power Administration, 5.11 NE Hwy 99, Vancouver, WA 98666

Q. In what capacity are you employed?

A. I am a Public Utilities Specialist in the Transmission Contracts, Strategy and Assessment Group in the Transmission Business Line.

Q. Please state your educational background.

A. I received a Bachelor of Science degree in Physics from University of Washington in 1971. My fields of concentration were quantum physics and mathematics. I am also a member of Phi Beta Kappa.

Q. Please summarize your professional experience.

A. In June 1970, I began work at BPA in the Engineering pool. In April 1972, I completed a variety of assignments required in the pool and was placed in the Division of Power Supply. My first assignment was in the Hydrometeorology section where I completed work on a stream flow forecasting computer model. While there, I also calculated Variable Energy Content Curves and Flood Control Elevation, and coordinated operations with the Reserve Control Center at the U.S. Army Corps of Engineers.

In November 1980, I began working in the Operations Planning branch where I was on the negotiating team for the Regional Act Power Sales Contract negotiations, represented BPA at the Centralia Owners' Meeting and the Trojan Fuels Subcommittee, and monitored compliance under the Computed Demand Contracts and the Service Exchange Agreements.

I moved to the Power Scheduling branch in July 1982. My principle duties in that group were to deal with the Pacific Northwest Coordination Agreement (PNCA) operational transactions and Hourly Coordination transactions. In addition, I provided scheduling procedures for contracts being negotiated.

In March 1992, I moved to the Contracts branch where I monitored studies of expected surpluses and deficits and made recommendations on economic actions to take to handle the surpluses and deficits. I was also Power Supply's representative to the Direct Services Industries.

In April 1994, I moved to the Resource Optimization Branch as a technical team lead for the groups which handle the Assured Operating Plan and the Detailed Operating Plan under the Canadian Treaty, the PNCA firm planning and operational scheduling, including the 30-day and 90-day forecasts. I was selected for a detail to head the BPA Trading Floor in March 1996.

When the detail ended in September 1996, I went to the Mid-Term Planning group where I analyzed and made recommendations on handling surpluses and deficits associated with the Federal Systems generation.

In June 1998, I came to Generation Scheduling to manage the training of new scheduler trainees and was on the negotiating team for the Slice Contract negotiating team.

I came to my current job in the Contracts, Strategy and Assessment Group of the Transmission Business Line in July 2003. I deal with FERC and Tariff Issues with FERC staff in Washington DC.

Q. *Please state your experience as a witness in previous proceedings.*

A. I was an expert witness in the 2002 PBL Rate Case where I dealt with questions relating to the Slice Rate.