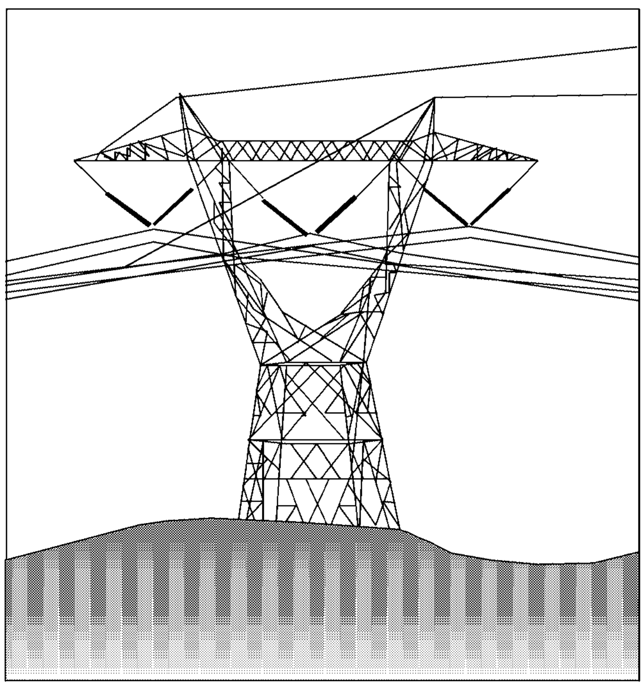
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N
T R A N S M I S S I O N B U S I N E S S L I N E

2004 FINAL TRANSMISSION PROPOSAL

ADMINISTRATOR'S RECORD OF DECISION

TR-04-A-01



MAY 2003

BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

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1.0 PROCEDURAL HISTORY

1.1 Introduction

This Record of Decision (ROD) contains the decisions of the Administrator of the Bonneville Power Administration (BPA) with respect to the adoption of transmission and ancillary services rates for the two-year rate period beginning October 1, 2003, and ending September 30, 2005 (fiscal years (FY) 2004-2005). These decisions are based on the record compiled in this rate proceeding. The transmission and ancillary services rates adopted in this ROD are the rates proposed as a result of a comprehensive settlement agreement between BPA's Transmission Business Line (BPA-TBL) and a diverse group of transmission customers, including BPA's Power Business Line (BPA-PBL), regional investor-owned utilities, partial and full requirements customers of the BPA-PBL, Direct Service Industrial (DSI) customers, and merchant generators. The decisions in this ROD to adopt the rates and charges proposed by the settlement agreement are not intended to create or imply any factual, legal, procedural or substantive precedent, or to create agreement to any underlying principle or methodology.

1.2 Procedural History Of The Rate Proceeding

BPA's 2004 Final Transmission and Ancillary Services Rate Proposal was preceded by several public processes that together formed the basis for the final transmission and ancillary services rates adopted herein. These processes are described below.

1.2.1 Other Proceedings

1.2.1.1 Programs in Review Workshops

In summer and fall 2002, TBL provided an opportunity for public participation and input on TBL program cost levels through the Programs In Review (PIR) process. PIR opened on June 19, 2002, with a widespread notification by mail to about 3,000 TBL customers and interested parties. Notices were also published on TBL's external website. During the PIR public process BPA conducted five regional workshops, beginning in July 2002, to ask for customer input. At the customers' request, an additional technical workshop was held in Portland on September 9, 2002, so staff could provide details of the proposed program levels.

A total of 130 entities attended the regional workshops. At the workshops, TBL discussed issues concerning future capital investments in the transmission system and proposed expense levels for transmission system development, operation, maintenance, and reliability for FY 2004 - 2006. TBL also provided informational materials through direct mailings, electronic mailings, and publication on TBL's external website, and through making staff available to answer questions. Workshop participants were advised that public comments and concerns offered during the process would inform the Administrator's decision with regard to spending levels. Those spending levels serve as the basis for the transmission revenue requirements, which are then used to set rates. Workshop participants provided substantial oral and written comments with regard to BPA's planned transmission capital spending and program expenditures.

The PIR process included a detailed discussion of capital spending levels and planned transmission system improvements, upgrades and reinforcement projects. The PIR workshops explored customers' and interested parties' views on: 1) operating and maintaining an aging transmission system; 2) building and maintaining a business framework in a changing energy industry; 3) building a transmission infrastructure to meet load growth, provide stability for existing contracts, ensure transmission system reliability, and integrate new resources; and 4) maintaining a skilled and trained workforce.

Customers participating in PIR asked TBL to keep transmission costs and rates low to help offset the effects of the downturn of the Northwest's economy, the higher and unstable cost of electrical power, and financial uncertainties facing most customers. The PIR process helped establish the following goals:

- Assure that rates will not rise, or that they will rise by a minimal amount through effective and efficient management of expense and capital program costs;
- Assure that there will be no shift in costs or risks with the building of infrastructure projects associated with integration of new generation projects and that those who receive the benefit of integration with the transmission system are being appropriately charged; and
- Manage the transmission system with sufficient resources and program levels to assure transmission system reliability and availability and to meet the challenges of a competitive and dynamic marketplace.

Revenue Requirement Study, TR-04-FS-BPA-01, at 4.

TBL accepted written and oral comments on proposed transmission capital spending and expenses through September 16, 2002. On December 19, 2002, I issued a letter entitled "Close out of the public process and final report on the Transmission Business Line's Programs in Review regarding expense and capital spending – Fiscal Years 2004 and 2005." My decisions were reflected in the revenue requirements, including repayment studies, in the TBL rate proposal, and are reflected in this Record of Decision.

1.2.1.2 Rate Case Workshops

In preparation for the 2004 Transmission Rate Case, the TBL held a public workshop for customers and interested parties on August 14, 2002. At that workshop, parties recommended that a rate case settlement be explored. During September and October 2002, the TBL met regularly with customers and interested parties to negotiate a settlement of transmission and ancillary service rate levels and resolution of other significant issues. The participants did ultimately reach a settlement that formed the basis of the TBL's proposal. The settlement process is discussed further in sections 1.2.2 and 1.2.2.1 of this ROD.

1.2.1.3 2002 Wholesale Power Rate Case

A number of issues that affect transmission and ancillary service rates have been addressed in BPA's 2002 Power Rate Case. On May 10, 2000, the Administrator established wholesale power rates for the period October 1, 2001, through September 30, 2006. Before the rates went into effect and before the Federal Energy Regulatory Commission (Commission) granted approval of the rates, the Administrator conducted an additional power rate proceeding and issued a supplemental Record of Decision on June 20, 2001. The Commission granted interim approval of the revised rates on September 28, 2001.

In the Power Rate Case, the Administrator made decisions regarding the following:

- a methodology for functionalizing generation and transmission costs;
- a methodology for functionalizing corporate overhead costs to the business lines;
- costs for generation inputs for ancillary services, including operating reserves, regulating reserve, and reactive power and voltage control from generation resources;
- the generation costs of station service and remedial action schemes;
- the allocation of the costs of generation integration and generator step-up transformers to the business lines;
- costs for the delivery of Federal power over third party transmission systems pursuant to General Transfer Agreements.

These decisions are not being revisited in this ROD. The decisions that were made in the power rate proceeding are incorporated into the final studies and final transmission and ancillary services rates adopted herein.

1.2.1.4 NEPA Compliance

BPA has assessed the potential environmental effects of its rate proposal, as required by the National Environmental Policy Act (NEPA). 42 U.S.C. § 4321 *et seq*. The NEPA analysis is conducted separately from the formal rate process. The following is a record of the NEPA analysis applicable to the 2004 transmission rates process.

BPA has previously evaluated the environmental impacts of a range of business structure alternatives that included, among other things, various rate designs for BPA's transmission products and services. Business Plan Final Environmental Impact

Statement, DOE/EIS-0183, June 1995 (Business Plan EIS). In August 1995, the BPA Administrator issued a Record of Decision (Business Plan ROD) that adopted the Market-Driven alternative from the Business Plan EIS. The Business Plan EIS and ROD were prepared to support a number of decisions, including decisions to establish or revise rates for products and services in rate cases in 1995 and thereafter. Business Plan EIS, section 1.4. Before reaching a final decision establishing or revising rates, the BPA Administrator reviews the Business Plan EIS and ROD to determine whether the rate proposal falls within the scope of the Market-Driven alternative evaluated in the EIS and adopted in the ROD. *Id.*; Business Plan ROD, section 8. If the rate proposal is found to be within the scope of this alternative, the Administrator may tier his decision for the rate proposal under NEPA to the Business Plan ROD and thus issue a "tiered" ROD. Business Plan ROD, section 8. Tiering a ROD to the Business Plan ROD helps BPA delineate decisions clearly, and provides a logical framework for connecting broad programmatic decisions to more specific actions. Business Plan EIS, section 1.4.

I reviewed the Business Plan EIS and ROD to determine whether BPA's 2004 Final Transmission and Ancillary Services Rate Proposal falls within the scope of the Market-Driven Alternative. BPA's 2004 Final Transmission and Ancillary Services Rate Proposal is consistent with BPA's Business Plan Environmental Impact Statement, DOE/EIS-0183, June 1995 (Business Plan EIS), and the Business Plan Record of Decision, August 15, 1995 (Business Plan ROD). As discussed in Section 5 of this ROD, this rate proposal is a direct application of the Market-Driven alternative, is not expected to result in significantly different environmental impacts from those examined for the Market-Driven alternative in the Business Plan EIS, and will assist BPA in accomplishing the goals related to this alternative identified in the Business Plan ROD. Therefore, the decision to implement this rate proposal is tiered to the Business Plan ROD.

BPA's evaluation under the Business Plan EIS is discussed in more detail in Section 5 of this ROD.

1.2.2 Formal Proceedings

Section 7(i) of the Northwest Power Act requires that BPA's wholesale power and transmission rates be established according to certain procedures. 16 U.S.C. § 839e(i). These procedures include, among other things, issuance of a Federal Register Notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, data, questions, and arguments; and a decision by the Administrator based on the record. The proceeding is governed by BPA's rules for general rate proceedings, §1010.9 of the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986) (hereinafter Procedures). These procedures implement the statutory section 7(i) requirements.

On December 20, 2002, BPA published a Notice of 2004-2005 Proposed Transmission Rate Adjustment, 67 Fed. Reg. 78090 (2002). The rate proposal was made by BPA's Transmission Business Line. BPA's Standards of Conduct do not permit preferential access by BPA's Power Business Line to information on BPA's transmission and ancillary services pricing. BPA-PBL therefore was a party to the transmission rate proceeding, with all of the rights and responsibilities of a party in the rate proceeding, including prohibition of *ex parte* communications.

The TBL held a public workshop on August 14, 2002, to begin discussing with interested parties issues associated with the 2004 Transmission Rate Case. At this workshop the parties discussed proposed schedules for future workshops and for the rate case, the scope of the rate case, and possible issues. The TBL and the parties also discussed the possibility of holding settlement discussions. At the parties' suggestion, TBL and interested parties met often over the next two months to negotiate a proposed settlement of the rate case. The first meeting was held on September 12, 2003. The parties continued to meet throughout October to negotiate the resolution of outstanding issues and the language of a settlement agreement. The TBL reached agreement with all of the parties that attended the negotiation sessions. Therefore, the TBL and the parties jointly developed a proposed settlement of the rate case. In the Settlement Agreement the TBL agreed to submit an Initial Proposal that reflected the agreed terms.

On November 4, 2002, the TBL posted the final Settlement Agreement on the TBL's web site and e-mailed the agreement to the TBL's transmission customers and to parties to the 2002 rate case. The TBL indicated that it would decide whether to proceed with the Initial Proposal outlined in the Settlement Agreement based on the executed agreements it received by November 12, 2002. It further indicated that it would execute the Settlement Agreement if, based on such executed agreements, it concluded that sufficient consensus supporting the Settlement Agreement existed. Virtually all of the TBL's customers signed the agreement, and on November 27, 2002, the TBL executed the Settlement Agreement.

On December 4, 2002, the TBL sent a letter to customers and interested parties informing them that it had executed the Settlement Agreement and including the rate case schedule it intended to propose. On December 20, 2002, BPA published a Federal Register Notice to formally initiate the rate case. The notice included the same schedule that was outlined in the TBL's December 4 letter.

The formal rate proceeding began with a prehearing conference on January 13, 2003. At the prehearing conference the TBL distributed its Initial Proposal to the parties. As contemplated by the Federal Register Notice, the TBL proposed a limited schedule until it was determined whether anyone that had not signed the Settlement Agreement would file an objection. 67 Fed. Reg. at 78090-91. The Hearing Officer established the following schedule: January 16—Clarification; January 21—Objections to Initial Proposal Due; January 23—Scheduling Conference; July 28—Record of Decision. He also ordered that any party that wished to engage in clarification had to notify the TBL of its intent to do so by noon on January 15. Finally, the scheduling order provided that parties waived their rights to challenge the TBL's Initial Proposal if they failed to file a notice of objection to the Initial Proposal by January 21, the date established in the procedural order. TR-04-O-02.

No party asked for clarification of the TBL's witnesses, and clarification was cancelled. In addition, no party filed an objection to the TBL's Initial Proposal. Every party to the rate case but one had signed the Settlement Agreement. The Scheduling Conference was held on January 23, 2003. Because no party intended to challenge the TBL's Initial Proposal, no dates were established for filing of testimony by the parties or for cross-examination of the TBL's witnesses. The date for the Record of Decision was changed to March 28, 2003. TR-04-O-06. It was later changed again to May 2, 2003. TR-04-O-07.

This Record of Decision, including the proposed 2004 Final Transmission and Ancillary Services rates, will be filed with the Commission. The Commission will review the proposed rates for conformance with statutory standards, and if the rates are confirmed and approved by the Commission, they will go into effect on October 1, 2003, for a 2-year period.

1.2.2.1 Opportunity To Participate In The Settlement Process

As discussed in Section 1.2.2, above, the Northwest Power Act establishes a hearing procedure to provide for adequate process during the ratemaking process. The TBL went to great lengths to ensure that parties to the proceeding had notice of all meetings and hearings, and that parties were able to participate in settlement discussions and express any concerns regarding the settlement process or the terms of the settlement.

The TBL provided parties a full opportunity to comment on the Settlement Agreement and the settlement process, in general, as negotiations occurred. Notices of all meetings and hearings were posted on the official rate case web address. The TBL arranged a telephone bridge to provide parties the opportunity to monitor meetings by telephone. Draft settlement agreements were periodically circulated electronically to all parties for review and comment. The Settlement Agreement was negotiated in open forums to which all interested parties were invited.

At the settlement negotiations certain parties were regular or frequent attendees and actively participated in negotiating the proposed transmission rates and terms and conditions. Other parties attended the settlement discussions intermittently to comment on issues and areas of direct concern to their interests. Some parties elected not to attend any hearings or participate in settlement negotiations.

1.2.2.2 Opportunity To Comment On The Final Settlement Agreement

As stated in section 1.2.2.1, all interested parties had ample opportunity to participate in the settlement discussions and to comment on or propose terms for the settlement agreement. In addition, as also mentioned, at the prehearing conference the Hearing Officer established a date of January 21 for parties to file objections to the TBL's Initial Proposal, which was based on the Settlement Agreement. Clarification was scheduled for January 16 so that parties had an opportunity for discovery before deciding whether to object.

As stated above, no party objected to the Initial Proposal. Therefore, no further formal proceedings were scheduled and the TBL proposed its Initial Proposal as the Final Proposal to establish transmission and ancillary services rates.

1.3 Legal Guidelines Governing Establishment Of Rates

1.3.1 Statutory Guidelines

The Pacific Northwest Electric Power Planning and Conservation Act sets forth various rate directives for BPA to follow in establishing rates. Section 7 of the Act directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839 e(a)(1). Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid by power revenues) over a reasonable period of years. *Id.*

Section 7(a)(2) of the Act sets forth the overall guidelines to be used in establishing rates. Under section 7(a)(2), rates are effective upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission that the rates

- are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System [FCRPS] over a reasonable number of years after first meeting the Administrator's other costs;
- are based upon the Administrator's total system costs; and
- insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

Section 7 also includes rate directives the Administrator is to use in establishing rates for particular customer classes. Finally, section 7 establishes procedural guidelines to be used when developing rates. These include publication of notice of the proposed rates in the Federal Register, a hearing before a hearing officer, and an opportunity to submit oral and written comments and to refute or rebut other material submitted for the record. 16 U.S.C. § 839e(i). BPA has expanded on these statutory directives by promulgating rules of agency procedure to aid in the conduct of rate hearings. 51 Fed. Reg. 7611 (1986).

In addition to the Northwest Power Act, the Flood Control Act of 1944 (Flood Control Act) and the Federal Columbia River Transmission System Act (Transmission System Act) include various rate directives. 16 U.S.C. §§ 825s and 838. Section 9 of the Transmission System Act provides that rates shall be established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. 16 U.S.C. § 838g. Section 10 of the Transmission System Act allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system. 16 U.S.C. § 838h.

The Flood Control Act contains ratemaking requirements similar to those in the Transmission System Act. Section 5 of the Flood Control Act directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 also provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years.

In addition, section 6 of the Bonneville Project Act (Project Act) requires that the Administrator prepare schedules of rates and charges for electric power sold to purchasers. 16 U.S.C. § 832e. Section 212(i) of the Federal Power Act sets forth additional ratemaking requirements applicable to BPA for transmission rates in connection with transmission service ordered by the Commission. 16 U.S.C. § 824k(i).

1.3.2 The Administrator's Broad Ratemaking Discretion

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) ("widest possible use" standard is so broad as to permit "the exercise of the widest administrative discretion"); *ElectriCities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit has recognized the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) ("Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA's statutory interpretation"); *PacifiCorp v. F.E.R.C.*, 795 F.2d 816, 821 (9th Cir. 1986) ("BPA's interpretation is entitled to great deference and must be upheld unless it is unreasonable"); *Atlantic Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities"); *cf. Aluminum Company of America v. Central Lincoln Peoples' Utility District*, 467 U.S. 380, 389 (1984) ("The Administrator's interpretation of the Regional Act is to be given great weight"); *Dep't of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) ("Insofar as agency action is the result of its interpretation of its organic statutes, the agency's interpretation is to be given great weight").

1.4 Confirmation And Approval Of Rates

BPA's rates become effective upon confirmation and approval by the Commission. 16 U.S.C. §§ 839e(a)(2) and (k). The Commission's review is appellate in nature, based upon the record developed by the Administrator. *United States Dep't of Energy-Bonneville Power Admin.,* 23 F.E.R.C. ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator, but may only confirm, reject or remand them. *United States Dep't of Energy—Bonneville Power Admin.,* 23 F.E.R.C. ¶ 61,378, 61,801 (1983). The Federal Power Act ratemaking provisions that apply to BPA for Commission-ordered transmission service did not alter this process. H.R. Conf. Rep. No. 102-1018, 102nd Cong., 2d Sess. 389 (1992), *reprinted in* 1992 U.S.C.C.A.N. 2480.

1.4.1 Transmission Rates

As noted above, under the Northwest Power Act the Commission reviews BPA's rates to determine whether they: (1) are sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; (2) are based on BPA's total system costs; and (3) as to transmission rates, equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2); *See also, United States Dep't of Energy—Bonneville Power Admin.*, 39 F.E.R.C. ¶ 61,078, 61,206 (1987). This limited Commission review permits the Administrator substantial discretion in the design of rates, which is not subject to Commission jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

Sections 211 and 212(i) of the Federal Power Act authorize the Commission to order transmission providers to provide transmission service upon application by an eligible entity. Section 212(i) of the Federal Power Act contains provisions specifically applicable to the Federal Columbia River Transmission System (FCRTS):

> (1) The Commission shall have authority pursuant to section 824i of this title, section 824j of this title, this section, and section 824l of this title to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that –
>
> (i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and
>
> (ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, or section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(l)(ii).

The Federal Power Act also authorizes the Commission to establish the terms and conditions of transmission service that it has ordered pursuant to the above authority. 16 U.S.C. § 824k(i)(2)(A). If the Administrator denies an application for transmission service, or if a party seeks access under "terms and conditions different than those offered by the Administrator" and the application is "filed within 60 days of the Administrator's final determination and in accordance with Commission procedure," the Commission may determine whether to grant or deny access and may establish the terms and conditions of the access. If the Administrator has conducted a hearing, the Administrator's hearing record is, with very limited exceptions, the basis for Commission review. 16 U.S.C. § 824k(2)(B).

The Federal Power Act preserved all existing ratemaking standards. In addition, the transmission rates for transmission service ordered by the Commission pursuant to the Federal Power Act must not be unjust and unreasonable or unduly discriminatory or preferential. 16 U.S.C. § 824k(i)(1)(B)(ii) and (ii).

The Joint Explanatory Statement of the Committee of Conference reinforces Congress's intent to leave prior law governing BPA intact. The Conference Report makes clear that, except for adding a new standard for Commission-ordered transmission, amendments to the Federal Power Act did not change the Commission's authority to review BPA's transmission rates:

> Rates for transmission services provided by BPA under an order issued under section 211 are to be established by BPA and reviewed by Commission through the same process and using the same statutory requirements as are applicable to all other transmission rates established by BPA, with the additional requirement that such rates for transmission services must also be just and reasonable and not unduly discriminatory or preferential as determined by the Commission, taking into account BPA's other statutory authorities and responsibilities.

H.R. Conf. Rep. No. 1021018, 102nd Cong., 2d Sess. 381 (1992) *reprinted in* 1992 U.S.C.C.A.N. 2472, 2480 (Conference Report). Thus, the Administrator's rate decisions remain entitled to substantial deference by the Commission.

In its final rule *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (Order 888), the Commission included a reciprocity provision applicable to all non-public utilities, such as municipal power authorities and federal power marketing administrations. 61 Fed. Reg. 21,540, 21,610-14, FERC Stats. and Regs. ¶ 31,036 (1996). Under the reciprocity provision, non-public utilities may voluntarily submit to the Commission a transmission tariff and a request for a declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. 61 Fed. Reg. at 21,613. If the Commission finds that a tariff contains terms and conditions that substantially conform or are superior to those in the Order 888 pro forma tariff, the Commission will deem it an acceptable reciprocity tariff and will require public utilities to provide open access service to that non-public utility. *Id.* at 21,614. In order to find that a non-public utility's tariff is consistent with the Commission's comparability standards, the Commission must have sufficient information to conclude that the rates the non-public utility charges itself are comparable to the rates it charges others. *Id.*

2.0 SETTLEMENT AGREEMENT

The TBL's rate proposal reflects the terms of the Settlement Agreement the TBL entered into with the parties. As noted above, all parties to the rate case but one executed the Settlement Agreement, and no party filed any objection to any aspect of the TBL rate proposal. Therefore, the TBL recommended that the Administrator establish rates consistent with the Settlement Agreement. In this Record of Decision, I adopt the proposed rates.

Under the Settlement Agreement, most Transmission and Ancillary Services rates are increased by 1.5%, while the Network Integration (NT) rate is increased by 2.6%. The additional increase in the NT rate is intended to recover $1 million in the cost of redispatch. Metcalf et al., TR-04-E-BPA-03, at 2. The NT rate includes a Base Charge and a Load Shaping Charge. The Base Charge is increased by 1.5%. The Load Shaping Charge is increased by 1.5% plus an additional $0.015/kilowatt per month to recover the additional $1 million, resulting in the overall increase in the NT rate of 2.6%. *Id.* at 3. Under the Settlement Agreement, the TBL will pay the PBL $3 million per year for redispatch services. A fixed annual payment is appropriate because of the difficulty of calculating the actual costs of redispatch. During the rate period, the TBL will work toward developing a methodology for determining the costs of redispatch and compensating parties that provide redispatch. *Id.* at 8.

In addition to the rate increase, the Settlement Agreement included several changes to the rate schedules. The rate schedule for Scheduling, System Control and Dispatch Service has been revised to clarify that the billing factor for each rate is based on all PTP transmission service the customer has reserved regardless of whether the customer actually schedules the transmission. This is how the TBL applies the rate now, and this revision is merely a clarification. *Id.* at 4.

The Energy Imbalance and Generation Imbalance rates are also being revised to establish three Deviation Bands for each rate and to eliminate the 100 mills per kilowatthour penalty charge except in the case of Intentional Deviations. Under the new Deviation Bands, Deviation Band 1 will apply to deviations within 1.5% of the scheduled amount, or 2 megawatts (MW), whichever is larger; Deviation Band 2 to the portion of the deviation that exceeds the larger of 1.5% or 2 MW but that is less than the larger of 7.5% or 10 MW; and Deviation Band 3 to any deviation outside of Band 2. *Id.* at 5. In addition, the charge for deviations increases as the size of the deviation increases: deviations in Band 1 are charged or credited BPA's incremental cost; those in Band 2 are charged or credited incremental cost plus or minus 10%; while those in Band 3 are charged incremental cost plus or minus 25%. The Band 3 rate is essentially a penalty, since deviations this large should not occur if the customer employs good scheduling practices. This rate design should encourage accurate scheduling while not penalizing customers that have only minor deviations. *Id.*

In addition, wind resources and new resources undergoing testing before commercial operation will be exempt from the Band 3 rate. The output of wind resources is not as predictable as the output of other resources. Therefore, even with good scheduling practices wind resources will be unable to consistently avoid the penalty rate.

Likewise, it is not generally possible to schedule accurately while testing new resources. Therefore, the penalty rate of Band 3 would not be a deterrent to poor scheduling practices in these cases, and it is appropriate to exempt these resources from the Band 3 rate. *Id.* at 6.

The Operating Reserves rate schedules are being revised to require generators in the BPA control area to pay for or return energy provided by BPA in the event of a contingency at that generator. Under current rate schedules, transmission customers pay for the cost of energy supplied during a contingency. In a given hour, however, several customers may be purchasing power from a given generator and scheduling that power. This has made it difficult to appropriately assign costs. In addition, parties to the power sales contracts have often had to adjust the contracts to avoid having the power purchaser pay twice for the same energy. This problem is avoided if the generator must pay for contingency energy. *Id.* at 6-7.

Finally, the generator can take action to minimize the number and duration of contingencies. Therefore, assigning the cost obligation to the generator is more consistent with principles of cost causation. *Id.* at 7.

The Unauthorized Increase Charge (UIC) is also being revised. Currently this charge is four times the monthly Point-to-Point (PTP) rate for long-term service. The new charge will be two times the rate applicable to the customer's transmission service, capped at two times the monthly charge for long-term service. For short-term service, this rate depends on the length of the customer's transmission reservation. The new UIC rate is more in line with the industry standard. *Id.*

The Settlement Agreement is attached as Appendix A to this ROD.

3.0 TRANSMISSION REVENUE REQUIREMENT

3.1 Introduction

BPA is a self-financed power marketing agency within the Department of Energy (DOE). Sales of electric power and transmission services provide BPA's primary sources of revenue. *See Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1116 (9th Cir. 1984). BPA's transmission and ancillary services rates are based on the Administrator's total system costs, and must produce revenues which are sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C.§ 839e(a)(2)(A) and (B). At the same time, BPA must set transmission and ancillary services rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. 16 U.S.C. § 825s, § 839g, and § 839(a)(1).

The proposed transmission and ancillary services rates established herein are designed to recover BPA's costs as set forth in the transmission revenue requirement. Rates to recover the costs set forth in BPA's generation revenue requirement were established in BPA's 2002 power rate case. *See* Final Power Rate ROD, WP-02-A-02 and Supplemental Power Rate ROD, WP-02-A-09. BPA has determined separate revenue requirements for generation and transmission since 1984, pursuant to a Commission order. *See United States Department of Energy - Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

Consistent with BPA's statutory obligations, the transmission revenue requirement is comprised of the Administrator's total transmission-related costs, including costs to assure the timely repayment of the Federal investment in BPA's transmission assets. The transmission revenue requirement establishes the level of revenue required to recover all of BPA's costs of transmitting electric power, which include: the Federal investment in transmission and transmission-supporting facilities; operations and maintenance (O&M) expenses; transmission marketing and scheduling expenses; the cost of generation inputs for ancillary services and reliability; and all other transmission-related costs incurred by the Administrator. *See* Final Revenue Requirement Study, TR-04-FS-BPA-01, at 1.

3.2 Revenue Requirement Development

BPA develops its revenue requirement to recover its costs in conformance with its statutory obligations and the financial, accounting, and repayment requirements of the Department of Energy's Order No. RA 6120.2.

The transmission revenue requirement for the FY 2004-2005 rate period was developed using a cost accounting analysis comprised of three components:

- Repayment studies are conducted to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission. Repayment studies are conducted for each year of the two-year rate test period, and include a 35-year repayment period.

- Operating expenses functionalized to transmission and minimum required net revenues (if needed) are projected for each year of the rate test period.

- Annual planned net revenues for risk (PNRR), if any, are determined based on the risks identified, BPA's cost recovery goals, and risk mitigation measures.

Id. at 1-2.

Based on these analyses, the transmission revenue requirement is set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives. Order No. RA 6120.2 requires that BPA demonstrate the adequacy or inadequacy of its existing rates to recover its costs. BPA conducted a current revenue test to determine whether revenues projected from current rates meet its cost recovery requirements and objectives for the rate test and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test demonstrated that current revenues are insufficient to meet cost recovery requirements and objectives for the rate test period and the repayment period. *Id.* at 2, 19.

Order No. RA 6120.2 also requires that BPA demonstrate the adequacy of proposed rates to recover its costs. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test and repayment period. The revised revenue test demonstrates that revenues from proposed transmission and ancillary services rates will recover transmission costs in the rate test period and over the ensuing 35-year repayment period. *Id.* at 2, 19-20. In this proceeding, rate test period costs are demonstrated to be recovered with a high confidence level. Risks have been quantified and analyzed, and risk mitigation measures designed to achieve at least a 95 percent probability that planned payments to Treasury will be recovered on time and in full over the two-year rate period. *Id.* at 2, 6-7.

The Settlement Agreement did not result in any changes to the method that BPA uses to develop the revenue requirement. *See* Settlement Agreement, Appendix A Changes from the initial proposal revenue requirement and repayment studies to the final proposal revenue requirement and repayment studies reflect updates based on actual financial data. In addition, in 2002 BPA issued short-term bonds that will come due during the rate period, in 2005. The maturities of these bonds were altered in the repayment study so as not to artificially increase the amortization schedule and the revenue requirement. In the final proposal revenue requirement BPA has adjusted the terms of these bonds to a 15-year period to conform to BPA's usual financing practice of issuing 15-year bonds. Homenick, Jensen et al., TR-04-E-BPA-05, at 10.

3.3 Changes in Calculation of Revenue Requirement

3.3.1 Revenue Financing

Revenue financing is an alternate financing mechanism to fund transmission capital investments. In calculating the revenue requirement, BPA assumes that cash generated annually by the transmission business operation is used to finance capital projects in lieu of issuing traditional debt instruments such as bonds. Homenick, Jensen et al., TR-04-E-BPA-05, at 2. In the initial proposal the transmission revenue requirements for Fiscal Years 2004 and 2005 included $20 million per year for revenue financing of capital investments. The Final Rate Proposal includes revenue financing of $15 million per year. Final Revenue Requirement Study, TR-04-FS-BPA-01, at 9.

The primary reason for utilizing revenue financing is to help BPA manage its borrowing authority constraints. As a government agency, BPA has a debt borrowing ceiling of $3.75 billion, established by the Federal Columbia River Transmission System Act of 1974, Pacific Northwest Electric Power Planning and Conservation Act of 1980, Continuing Appropriations for 1983 and Energy and Water Development Appropriation Act of 1984. (Congress increased BPA's borrowing authority by $700,000,000 after the rate case process concluded. That increase does not affect the analysis of appropriate revenue financing in this case.) Current projections of capital expenditures show that BPA would run out of borrowing authority around FY 2005 or FY 2006. Through revenue financing BPA preserves a portion of its finite borrowing authority by avoiding the issuance of additional debt. Revenue financing also improves BPA's financial profile because BPA is not relying entirely on debt financing. Rating agencies look more favorably on entities that use less than 100% debt financing. Therefore, a balanced approach that combines debt financing and revenue financing may result in higher financial ratings for BPA and lower interest rates on future BPA bonds. Homenick, Jensen et al., TR-04-E-BPA-05, at 3.

Although no revenue financing was included in 2002 rates, BPA has used revenue financing in the past. In each case, the amount of the revenue financing has been about 5% of the projected capital investments for the rate period. The $20 million of revenue financing in the initial proposal also represents about 5% of projected capital investments. *Id.* at 3-4. In the final proposal the revenue financing was reduced to $15 million per year to accommodate increased interest expense because 2002 borrowings were greater than forecast in the initial proposal. By reducing revenue financing by $5 million per year BPA is able to demonstrate cost recovery in both 2004 and 2005. For each year of the rate period the revenue financing is manifest as the difference between the increase in long-term debt, or the projected borrowing for the year, and the cash used for utility plant, or the projected capital expenditures for the year. That difference affects the annual increase or decrease in cash, which factors into the determination of Minimum Required Net Revenues. *Id.* at 4-5.

3.3.2 Sales of Delivery Facilities

As in the last rate filing, the sale of Delivery segment facilities resulting from the 1996 Sale of Facilities Policy has had an effect on the revenue requirements, because of both actual and forecasted sales. From FYs 1997 through 2002, sales proceeds totaled $41 million, with a book value for the facilities sold of $33.3 million. Proceeds from sales closed in FYs 1997 through 1999 were applied as additional amortization to transmission debt ($23.4 million) to reduce overall repayment obligations, consistent with the transfer of title of these assets. An additional $9.9 million remains to be applied as amortization. In order to provide the same effect in revenue requirements as if this amount had been used for amortization, it is included in the transmission cash reserves to provide interest income to offset interest expense on outstanding debt. As such, it is not available for risk mitigation. Homenick, Jensen et al., TR-04-E-BPA-05, at 4-5.

TBL staff identified the facilities projected to be sold by the end of the current rate period. The gross investment in those facilities was removed from the plant-in-service in 2003. The forecasted proceeds, along with the actual proceeds, were included in the calculation of interest income on cash balances that is an offset to interest expense in the revenue requirement. The amount equivalent to the book value is unavailable for risk mitigation. Although the sales policy will remain in effect during the rate period, the revenue requirement does not reflect any sales during the rate period. *Id.* at 6.

3.3.3 Reshaping Amortization

For the test of the adequacy of proposed rates to recover costs, it was necessary to move $1.5 million of planned amortization from FY 2004 to FY 2005. *See* Final Revenue Requirement Study, TR-04-FS-BPA-01, at 20. The proposed revenues were insufficient to cover all cash requirements in FY 2004, but were more than sufficient in FY 2005. Consequently, the planned amortization was reshaped to accommodate this pattern. This reshaping did not change the total amount of amortization in the rate period. Reshaping amortization has been a long-standing practice in previous rate filings in order to ensure adequate cash flows from proposed rates to meet annual cash requirements. Because reshaping was not necessary in establishing 2002 rates, however, this is a change from the current rate period.

3.4 Repayment Studies

Repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

In this rate filing, as in the previous transmission rate filing, the repayment period has been set at 35 years. This study horizon reflects the fact that the longest term of bonds BPA has issued has been 35 years. As such, all outstanding appropriations and bonds in the transmission system are fully repaid within this period.

The Revenue Requirement Study includes the results of transmission repayment studies for each of the two years in the rate test period, FYs 2004 and 2005. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations on appropriations and on bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also is included in the repayment study, consistent with the requirements of RA No. 6120.2. Final Revenue Requirement Study, TR-04-FS-BPA-01, at 10.

Historical appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 40 years, taking into account the estimated average service lives for investments and prudent financing and cash management factors. In the repayment studies, all projected bonds have a term of 35 years for transmission investment and 15 years for environmentally-related investment in transmission maintenance projects. The repayment study establishes a schedule of planned amortization payments and resulting gross interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period. *Id.* at 10-11.

3.5 Planned Net Revenues for Risk

In the 1993 Final Rate Proposal BPA determined that, as a long-term policy, it would plan to set its total rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each 2-year rate period. 1993 Final Rate Proposal, Administrator's ROD, WP-93-A-02, at 72-73.

The probability of meeting its Treasury payment obligation is the primary measure of BPA's ability to recover its costs. To achieve the above Treasury payment probability (TPP), the following risk mitigation "tools" were considered:

1. Starting reserves: Starting financial reserves include cash in the BPA Fund and the deferred borrowing balance attributed to the transmission function. The risk-adjusted value for starting reserves is projected to total $182 million at the beginning of FY 2004. Revenue Requirement Study, TR-04-FS-BPA-01, at 6.

2. Planned Net Revenues for Risk: PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in costs and revenues and achieve the TPP goal. No PNRR were required to meet the TPP standard in this rate filing. *Id.* at 6-7.

3. Two-Year Rate Period: The rates established in this record will be effective for a two-year rate period. The ability to revise rates after two years, or more frequently if necessary, serves as an important risk mitigation tool. A two year rate period limits the effects of uncertainty. *Id.* at 7. Moreover, even

though I am adopting the rate settlement in this ROD, BPA retains the right to raise rates even during the rate period if necessary.

3.6. Transmission Risk Analysis

To quantify risks, the effects of uncertainty in costs and revenues on transmission cash flows was analyzed using a Monte Carlo simulation method. The analysis estimated the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year transmission cash reserve, after Treasury payments are made, is sufficient to cover the transmission working capital requirement of $20 million. The working capital threshold is based on the monthly net cash flow patterns and requirements for the transmission function. *Id.*

The risk analysis covers the period FY 2003 through FY 2005, using FY 2002 as the historical period. This time frame is used to permit analyzing the change in revenues, costs, and accrual to cash adjustments that is expected to occur between the development of the final rate proposal and the end of the rate period. The advantage to this approach is that cash reserves at the start of the FY 2004-2005 rate period may be estimated, thus helping define the starting conditions for the next rate period. *Id.* at 8.

The foundation of the risk analysis Monte Carlo simulation is a transmission financial spreadsheet model. This model was developed to estimate the effects of risk and risk mitigation on end-of-year cash reserves and the likelihood of successful Treasury payment during the rate period. Cash reserve levels at the end of the fiscal year determine whether BPA is able to meet its Treasury payment obligation. *Id.* If cash reserves are sufficient to cover working capital requirements at the end of the fiscal year, it can be assumed that the Treasury payment was made in full and on time that fiscal year. End-of-year cash reserves during the rate period are the main outcome of interest in the model. Parameters for the probability distributions were developed from historical data and analysis of risk factors. *Id.*

The transmission risk analysis simulation performed for this rate case resulted in a Treasury payment probability greater than 95% for the FY 2004 through 2005 rate period. *Id.* at 2, 6.

4.0 TRANSMISSION AND ANCILLARY SERVICES RATES

4.1 Description of Transmission Rates and Ancillary Services Rates

BPA's 2004 Final Transmission and Ancillary Services Rate Proposal is attached as Appendix B to this ROD. The rates reflect the rate provisions of the Settlement Agreement. The majority of the proposed rates apply to transmission service under BPA-TBL's proposed OATT. The rates applicable to the OATT are the Network Integration (NT-04) rate, Point-to-Point (PTP-04) rate, Southern Intertie (IS-04) rate, Montana Intertie (IM-04) rate, and the Ancillary and Control Area Services (ACS-04) rates. The proposed Use of Facilities (UFT-04) rate and Advanced Funding (AF-04) rate may be used in conjunction with open access service. The UFT-04 and AF-04 rates also apply to pre-OATT transmission service. The ACS-04 rate schedule includes rates for the six ancillary services included in OATT service, plus rates for four control area services that are required for reliability of resources and loads in the BPA Control Area. In addition, the Integration of Resources (IR-04) rate and the Formula Power Transmission (FPT-04) rates are proposed for pre-OATT firm transmission contracts. Two rates, Townsend-Garrison (TGT-04) and Eastern Intertie (IE-04), are available to parties to the Montana Intertie Agreement. A variety of other charges are also proposed, including a Delivery Charge for use of low-voltage DSI and utility delivery facilities, a Power Factor Penalty Charge, and a GTA Delivery Charge.

4.2 Equitable Allocation

4.2.1 The Equitable Allocation Standard

Section 7(a)(2)(C) of the Northwest Power Act provides that the Commission will confirm and approve BPA's rates upon a finding that "such rates equitably allocate the costs of the Federal transmission system to Federal and non-Federal power using the system." 16 U.S.C. § 839e(a)(2)(C). In addition to the equitable allocation standard, section 7(A)(1) of the Northwest Power Act and section 10 of the Transmission System Act provide that rates must be established to recover the costs associated with transmission of electric power "in accordance with sound business principles." 16 U.S.C. § 839(a)(1), 16 U.S.C. § 838h. Section 7(a)(1) of the Northwest Power Act incorporates by reference section 9 of the Transmission System Act, which provides that rates "shall be fixed and established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles." 16 U.S.C. § 838g. Similar language is also contained in section 5 of the Flood Control Act. 16 U.S.C. § 825s.

Taken together, the "equitable allocation" and "widest possible use consistent with sound business principles" standards evince a Congressional intent to give BPA substantial ratemaking discretion. The equitable allocation standard does not expressly or implicitly mandate that each of BPA's transmission rates must reflect costs that are equitably allocated. Rather, it requires equitable allocation of transmission rates in the aggregate.

Furthermore, Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the authority to determine the appropriate method for recovering transmission costs that have been allocated to Federal use. Section 7(e) provides that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time of day, seasonal rates or other rate forms." 16 U.S.C. § 839e(e). Accordingly, BPA can choose among a variety of rate designs for particular transmission rates, as long as BPA's transmission rates in total are designed to ensure that the costs of the transmission system are equitably allocated.

4.2.2 Comparability

With enactment of Energy Policy Act of 1992 (EPA'92), Congress declared a national policy choice of encouraging the development of competitive power markets through the availability of open transmission access. EPA'92 amended sections 211 and 212 of the Federal Power Act to allow the Commission to order transmitting utilities to provide transmission service to eligible transmission customers. The definition of transmitting utility includes a Federal Power Marketing Administration, such as BPA. The Federal Power Act, as amended, contains provisions specifically applicable to the FCRTS. 16 U.S.C. § 824k(i)(1).

Since passage of EPA'92, the Commission has actively declared its policy to remove barriers to competition in the electric energy industry by promoting open access transmission, both through rulings on a case-by-case basis, and through rulemaking. Order No. 888, 61 Fed. Reg. at 21,550. The construct that has emerged relies on the concept of "comparability." As the Commission stated in Order 888:

> The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive. In reaching that conclusion, the Commission broadened its undue discrimination analysis . . . to include a focus on the rates, terms and conditions of a utility's own uses of the transmission system.

Id. at 21,548. The Commission further stated that "an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of the system." *Id.,* citing *American Electric Power Service Corporation*, 67 FERC. ¶ 61,317, at 61,490 (1994). In addition, the Commission required that certain ancillary services that are needed to provide basic transmission service be provided to transmission customers. Order 888, 61 Fed. Reg. at 21,581. The Commission has also required jurisdictional utilities to functionally unbundle transmission from generation. *Id.* at 21,552.

Although Order 888 does not apply to BPA, the Commission has declared its intention to apply the policies it announces as broadly as it can through sections 211 and 212 of the Federal Power Act, to promote a national policy of open transmission access. *Id.* at 21,572-73. In furtherance of this goal, the Commission included a reciprocity provision in Order 888, allowing non-public utilities to voluntarily submit to the Commission a tariff and a request for a declaratory order that the tariff meets the Commission's comparability standards. *Id.* at 21,613. Thus, BPA sets rates for transmission over the FCRTS to conform to the policies announced in Order No. 888. Equitable allocation and comparability are similar concepts in that, under each, Federal and non-Federal power have access to the FCRTS under the same or comparable rates, terms and conditions. *Id.*

4.2.3 Settlement Rates Satisfy Equitable Allocation Standard And Comparability

The proposed transmission and ancillary service rates provide an equitable allocation of Federal transmission costs between Federal and non-Federal power. In previous rate cases, BPA segmented the transmission system and developed a methodology to allocate costs between Federal and non-Federal power using the transmission system. These segmentation and cost allocation methodologies formed the basis for the demonstration that costs were equitably allocated. BPA has not performed a segmentation study for this rate case. Nevertheless, for two reasons the proposed settlement rates represent an equitable allocation between Federal and non-Federal power using the system. TR-04-E-BPA-03, at 9.

First, equitable allocation between Federal and non-Federal power is achieved through adherence to the principle of comparability. Prior to 1996, when most transmission for Federal power was provided for in bundled power sales contracts, an allocation of costs in the rate case was needed to demonstrate equitable allocation of transmission costs between Federal and non-Federal power. Under BPA's Open Access Transmission Tariff, purchasers of transmission for Federal power, including both the PBL and the PBL's customers, receive the same service and pay the same rates as purchasers of transmission for non-Federal power. An equitable allocation of transmission costs between Federal and non-Federal power is achieved through application of the same rates to the two classes of service. *Id.*

Second, equitable allocation is demonstrated by the breadth of the settlement and the diversity among the settling parties. The settling parties include the PBL and PBL full requirements customers; large partial requirements customers that both buy Federal power and wheel large amounts of non-Federal power; large wheeling customers, such as the region's Investor Owned Utilities, which purchase little Federal power; and power marketers and resource developers. BPA would not have been able to obtain the agreement of such a large group of customers with such diverse interests unless the proposed allocation of costs was equitable.

5.0 Environmental Analysis

BPA first established separate rates for power, transmission and ancillary services products and services in the 1996 rate proceeding. BPA unbundled these services and proposed separate rates in response to both the competitive market for wholesale bulk power and Order 888. 1996 Final Rate Proposal Administrator's Record of Decision, WP-96-A-02, Chapter 2. Although Order 888 does not apply directly to BPA, BPA has committed to voluntarily provide open access transmission services and associated rates in a manner comparable to that required of public utilities regulated by the Commission under the Federal Power Act. In the 2004 Transmission Rate Proceeding new Transmission and Ancillary Services rates are being established to be effective October 1, 2003.

In order to participate successfully in the increasingly competitive wholesale electricity market, BPA needed an adaptive policy to guide the agency in meeting both its business and public benefit missions. BPA therefore prepared the Business Plan EIS and Business Plan ROD to support a number of decisions, including decisions to establish rates for products and services in rate cases in 1995 and thereafter. Business Plan EIS, section 1.4. BPA identified several goals, including: achieving strategic business objectives; competitively marketing BPA's products and services; providing for equitable treatment of Columbia River fish and wildlife; achieving BPA's share of the Northwest Power Planning Council conservation goal; establishing rates that are easy to understand and administer, stable, and fair; recovering costs through rates; meeting legal mandates and contractual obligations; avoiding adverse environmental impacts; and establishing productive government-to-government relationships with Indian Tribes. *Id.* section 1.2; Business Plan ROD, sections 5 and 6.

BPA's Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. Business Plan EIS, section 2.4. A series of policy options, or modules, was developed for four key areas, including rate design, to allow variations of the alternatives. The alternatives and modules are designed to cover the range of options for the important issues affecting BPA's business activities, as well as the impacts of those options, and variations can be assembled by matching issues and substituting modules among the six alternatives. *Id.* section 2.1.2. All of the alternatives and modules are examined under two widely different hydro operations strategies that serve as "bookends" for reasonably possible hydro operations. These alternatives thus represent a range of reasonable alternatives for BPA's business activities and BPA's ability to balance costs and revenues.

The 19 key policy issues analyzed across the alternatives include several issues related to transmission services: Unbundling of Transmission and Wheeling Services; Transmission and Wheeling Pricing; Transmission System Development; Transmission Access; Assignability of Rights Under BPA Wheeling Contracts; Retail or DSI Wheeling; Customer Service Policy and Sub-transmission; and Operations, Maintenance, and Replacement of the Transmission System. *Id.* section 2.4. These issues incorporate information about the various rate designs and charges that could be implemented for BPA's transmission products and services. *Id.* sections 2.4.1.6 and 2.4.2.2, Appendix B. Table 2.4-1 of the EIS shows how the alternatives evaluated in the EIS treat these issues, and Figure 2.4-3 shows the major influences, including products and pricing, on transmission development.

The Business Plan EIS focuses on BPA's relationships to the market. The environmental impacts are determined by the market responses to BPA's marketing actions, rather than by the actions themselves. *Id.* sections 2.1.5 and 4.1.2. Four types of market responses are identified: resource development; resource operations; transmission development and operation; and consumer behavior. These market responses determine the environmental impacts, which include air, land, and water impacts, as well as socioeconomic impacts. *Id.* Figure 2.1-1 and figure S-2. Figure 2.4-1 shows how decisions on key issues that change BPA rates affect market responses and the environment. *Id.* section 2.4.2.1.

To determine the potential environmental consequences of the various alternatives, the EIS identifies general market responses to the 19 significant policy issues. *Id.* Table 4.2-1. The market responses to products and services and to rates are discussed for each of the alternative business directions. *Id.* sections 4.2.1 and 4.2.2. The market responses and the environmental consequences are discussed both in general terms and in terms specific to each alternative. *Id.* section 4.3. Table 4.3-1 details the typical environmental impacts from power generation and transmission. Section 4.4 presents the market responses and environmental impacts by alternative, under two "bookend" hydro operation scenarios. Table 4.4-19 summarizes the key environmental impacts by alternative. *Id.* section 4.4.3.8. In addition, Appendix B to the Business Plan EIS includes an extensive evaluation of rate design, including market response and environmental impacts. *Id.* Appendix B.

As can be seen from the environmental analysis presented in the Business Plan EIS, the potential environmental impacts of all business direction alternatives fall within a fairly narrow band, and several of the key impacts are virtually identical across alternatives. In addition, the costs of environmental externalities differ only slightly among alternatives. *Id.* Table 4.4-20. Thus, the differences among alternatives in total environmental impacts are relatively small. Each of the alternative business directions examined in the Business Plan EIS is also evaluated against the purposes for the action to determine how well each of the alternatives meets the need. *Id.* section 2.6.5; Business Plan ROD, Table 2.

Based on the evaluation of potential environmental impacts and the comparison of each alternative to the identified purposes, the Administrator chose the Market-Driven alternative. Business Plan ROD, section 6. Although the Status Quo and the BPA Influence alternatives were the environmentally preferred alternatives, the differences among alternatives in total environmental impacts were relatively small, and BPA's ability to meet its public and financial responsibilities would be weakened under these two alternatives. In addition, other business aspects, including loads and rates, showed greater variation among the alternatives. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also assists BPA in maintaining the financial strength necessary to continue a relatively high level of support for public service benefits, such as energy conservation and fish and wildlife mitigation activities.

Recognizing that the Administrator could select a variety of actions, BPA included many mitigation response strategies in the Business Plan EIS and ROD to address changed conditions and allow the agency to balance costs and revenues. These strategies include measures that BPA could implement to increase revenues (including rates), decrease spending, and/or transfer costs if its costs and revenues do not balance. Business Plan EIS, section 2.5; Business Plan ROD, section 7. The strategies enable BPA to best meet its financial, public service, and environmental obligations, while remaining competitive.

The Business Plan EIS and ROD also documented a decision strategy for tiering subsequent business decisions to the Business Plan ROD. Business Plan EIS section 1.4; Business Plan ROD, section 8. For each such decision, the BPA Administrator reviews the Business Plan EIS and ROD to determine whether the proposed action falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the action is found to be within the scope of this alternative, the Administrator may tier his decision for the proposed action to the Business Plan ROD and thus issue a "tiered" ROD. Tiering a ROD to the Business Plan ROD helps BPA delineate decisions clearly, and provides a logical framework for connecting broad programmatic decisions to more specific actions. Business Plan EIS, section 1.4.

Based on a review of the Business Plan EIS and ROD, I have determined that the 2004 Final Transmission and Ancillary Services Rate Proposal is a direct application of the Market-Driven alternative. This rate proposal is consistent with the competitive and unbundled yet cost-based characteristics of the Market-Driven alternative, and the issues related to this proposal are consistent with the analysis of key policy issues related to transmission services identified for the Market-Driven alternative. *Id.* sections 2.2.3 and 2.6. In addition, this rate proposal is similar to the type of rate designs evaluated in the Business Plan EIS. *Id.* sections 2.4.1.6 and 2.4.2.2, Appendix B. Because of these consistencies and similarities, implementation of this rate proposal would not be expected to result in significantly different environmental impacts from those examined for the Market-Driven alternative in the Business Plan EIS.

Furthermore, the 2004 Final Transmission and Ancillary Services Rate Proposal will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD. This alternative was selected as BPA's business direction because, among other reasons, it allows BPA to: (1) recover costs through rates; (2) competitively market BPA's products and services; (3) develop rates that meet customer needs for clarity and simplicity; and (4) continue to meet BPA's legal mandates. The current rate proposal allows BPA to continue to recover its transmission and ancillary service costs though its rates while remaining competitive. In addition, the rate design included in the rate proposal has been made as clear and simple as possible, given the various types of service covered in the proposal. Finally, BPA believes that it will be able to meet its legal mandates under the rate proposal.

Thus, the 2004 Final Transmission and Ancillary Services Rate Proposal falls within the scope of the Market-Driven alternative identified and evaluated in the Business Plan EIS and adopted by the Administrator in the Business Plan ROD. The decision to implement this rate proposal therefore is tiered to the Business Plan ROD, as provided for in the Business Plan EIS and Business Plan ROD.

6.0 ADMINISTRATOR'S DECISION

As required by law, the transmission and ancillary services rates established and adopted by this ROD have been set to recover the costs associated with the transmission of electric power, including the amortization of the Federal investment in the FCRTS over a reasonable period of years, and all other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. The rates have been established with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. In addition, the transmission and ancillary services rates are designed to equitably allocate the cost of the Federal transmission system between Federal and Non-Federal power using the system. Finally the rates satisfy the Commission's comparability standards, as the transmission of Federal power will be charged the same rates as the transmission of non-Federal power under BPA-TBL's open access transmission tariff.

BPA must establish its transmission and ancillary services rates in a proceeding pursuant to section 7(i) Northwest Power Act. BPA began a formal 7(i) proceeding on January 13, 2003. The hearing officer has assured that all interested parties in that proceeding were afforded the opportunity for a full and fair evidentiary hearing, as required by law. BPA must also evaluate the potential environmental impacts of the rate proposal and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan EIS details the environmental impacts of BPA's 2004 Transmission and Ancillary Services rate proposal. The environmental analysis contained in the Business Plan EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and the requirements of law, I hereby adopt the attached Transmission and Ancillary Services Rate Schedules as the Bonneville Power Administration's 2004 Final Transmission and Ancillary Services rate proposal. The rate levels and other provisions in the attached rate schedules are consistent with the rates proposed in the Settlement Agreement. In accordance with the Commission's filing requirements applicable to Federal power marketing administrations, 18 CFR § 300.10(g), I hereby certify that the Transmission and Ancillary Services rate proposal adopted herein are consistent with applicable laws and are the lowest possible rates, consistent with sound business principles.

Issued in Portland, Oregon this 2nd day of May, 2003.

Stephen J. Wright
Administrator
Bonneville Power Administration

Appendix A

Settlement Agreement

SETTLEMENT AGREEMENT
Bonneville Power Administration 2004 Transmission Rate Case

The undersigned signatories to this Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2004 Transmission Rate Case (Rate Case), the Transmission Business Line (TBL) will submit a proposal (Initial Proposal) commencing the rate process for the period FYs 2004 – 2005 (Rate Period) that reflects the following:

   a. Current 2002 transmission rates will be increased by 1.5%, and the 2002 transmission rate schedules and the general rate schedule provisions will otherwise be unchanged except as explicitly set forth below. If a rate schedule includes a maximum charge for any rate, the increase in rate level will be applied to the maximum charge. The following transmission rates will be increased by 1.5%: FPT-02.1; IR-02; NT-02 (Base Charge and Load Shaping Charge); PTP-02; IS-02; IM-02; and Delivery Charge (Utility Delivery). The FPT-02.3 charges will remain in effect for FY 2004, and will be increased by 3% for FY 2005. The increase in the FPT-02.3 rate shall be considered an adjustment to such rate. Therefore, such rate will next be subject to adjustment on October 1, 2007.

      In addition, the General Transfer Agreement Delivery Charge will increase 1.5%.

   b. In addition to the above increase, the NT Load Shaping Charge will be increased by an additional $0.015/kW per month to recover approximately $1 million of the total amount paid by the TBL to the BPA Power Business Line (PBL) for redispatch associated with NT service. The NT rate schedule will otherwise be unchanged.

   c. The ACS rate schedule and General Rate Schedule Provision Spill Condition definition will be as specified in Attachment 1 to this Settlement Agreement.

   d. The Unauthorized Increase Charge (UIC) rate under all rate schedules that apply to Point-to-Point Transmission Service (the PTP, IS, and IM rate schedules) will equal two times the transmission rate (which, for short-term service, is based on the length of the reservation), but shall not in any month exceed 2 times the monthly rate for Long-Term Firm Transmission Service under such rate schedule. The UIC under the NT rate schedule will equal two times the NT Base Charge. Examples of the calculation of the UIC charge are shown in Attachment 2.

   The Initial Proposal transmission and ancillary service rates are shown in Attachment 3.

2. Redispatch

   a. The signatories recognize and agree that there is value associated with the redispatch of hydro resources. The signatories further agree that during the FY 2004-2005 Rate Period they will work towards devising an approach so that hydro-electric and other generation can be appropriately compensated for redispatch in future rate periods. If TBL develops information during the Rate Period regarding the amount of redispatch by PBL, TBL will provide such information to any party requesting it.

b. The revised Open Access Transmission Tariff (OATT) Attachment K (shown in Attachment 4 to this Settlement Agreement) will replace the existing Attachment K. The TBL will compensate the PBL for redispatch services associated with Attachment K by paying PBL $3 million per year in FY 2004 and FY 2005 for all such services provided during such period. In the interest of reaching a settlement the signatories have agreed to this amount of compensation to the BPA PBL for providing redispatch during the Rate Period. However, nothing in this Settlement Agreement nor actions taken pursuant to section 2.a, above, will serve as a precedent for any methodology for implementing or valuing redispatch for future rate periods, or for the purpose of determining the rights of an RTO or any other regional transmission provider to require redispatch.

c. TBL will submit the revised Attachment K (Attachment 4 to this Settlement Agreement) to the Federal Energy Regulatory Commission (FERC) as a proposed amendment to BPA's Open Access Transmission Tariff, and will request that it be effective as of October 1, 2003. The signatories agree not to challenge the approval of the revised Attachment K by FERC, and, if FERC approves the revised Attachment K without change, the signatories agree not to challenge such approval in any judicial forum.

3. The TBL will convene a Business Practices and Systems Forum as set forth in Attachment 5 to this Settlement Agreement.

4. No later than October 1, 2003, TBL will have appropriate scheduling and reservation systems in place so that customers are able to redirect firm transmission service by modifying points of receipt and delivery and are able to return to their original points upon expiration of the redirected service, in accord with FERC policy. To the extent permitted by FERC policy, customers will be permitted to redirect firm transmission irrespective of other requests for firm transmission if and to the extent that the redirected firm transmission service would make the same use of the same constrained paths as the original transmission service to the original points of receipt and delivery. TBL will make all reasonable efforts to have such systems available for testing by March 1, 2003.

5. The signatories agree not to contest any aspect of the TBL's Initial Proposal, including but not limited to the level of any transmission or ancillary or control area services rate or any of the elements thereof, the methodologies and principles used to derive such rates, or any aspect of the rate schedules, and agree to waive their rights to cross-examination and discovery with respect thereto. If, however, the TBL does not submit an Initial Proposal consistent with the terms of this Settlement Agreement, the signatories may contest any aspect of the TBL's proposal.

6. If no party in the Rate Case contests any aspect of the TBL Initial Proposal, the TBL will propose to the Administrator that he adopt the TBL's Initial Proposal and establish rates consistent therewith.

7. The signatories will move the Hearing Officer to specify a date within a reasonable time of the prehearing conference by which any party to the Rate Case that has not executed this Settlement Agreement i) must object to the settlement proposed in this Settlement Agreement and identify each issue such party chooses to preserve for hearing; or ii) be deemed to have waived any right to object to the settlement proposal or preserve issues for hearing. If no party objects to the settlement proposal and preserves issues for hearing, the TBL shall propose to the Administrator that he adopt the Initial Proposal in its entirety. In the event that any party does so object, the TBL may, but shall not be required to, revise the

Initial Proposal as it believes appropriate, either after such party states its objection or after parties file their direct testimony. If the TBL decides not to revise its Initial Proposal, the TBL will propose to the Administrator that he adopt the Initial Proposal in its entirety. If the TBL decides to revise its Initial Proposal, the TBL and the parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing the TBL a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. The signatories may contest any aspect of such revised proposal.

8. If the TBL submits an Initial Proposal consistent with the terms of this Settlement Agreement, and does not submit a revised proposal pursuant to section 7, the signatories agree not to enter any evidence into the Rate Case or make any argument in the Rate Case contesting any provision of section 36 of BPA's current OATT. If the Administrator establishes transmission rates consistent with the TBL's Initial Proposal and submits such rates to FERC for confirmation and approval, the signatories agree not to make any such argument before the FERC or any judicial forum during the Rate Period.

9. Nothing in this Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's transmission rates or the signatories' rights to challenge such revisions.

10. If the Administrator establishes transmission rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval only under the applicable standards of the Northwest Power Act and as part of a reciprocity filing, the signatories agree not to challenge such confirmation and approval of such rates or any element thereof, including the methodologies and principles used to establish such rates, or support or join any such challenge, and agree not to challenge such rates or any element thereof, including the methodologies and principles used to establish such rates, in any judicial forum. In addition, the TBL's commitment in section 4 of this Settlement Agreement shall apply only if the Administrator establishes rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval.

11. The signatories agree that they will not assert in any forum that anything in this Settlement Agreement or any action with regard to this Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

12. By executing this Settlement Agreement, no signatory waives any right to pursue BPA OATT dispute resolution procedures consistent with BPA's OATT (including without limitation any complaint concerning implementation of BPA's OATT) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.

13. Nothing in this Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Settlement Agreement may be executed in counterparts.

__________________________for

____________________________ Date ______

Party

Attachment 1

SCHEDULE ACS-04
ANCILLARY SERVICES AND
CONTROL AREA SERVICES Rate

SECTION I. AVAILABILITY

This schedule supersedes Schedule ACS-02. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k). Service under this schedule is subject to BPA-TBL's General Rate Schedule Provisions (GRSPs).

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Provider is required to offer to provide (a) Operating Reserve – Spinning, and (b) Operating Reserve – Supplemental to the Transmission Customer serving load with generation located in the Transmission Provider's Control Area. The Transmission Customer serving load with generation located in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Service rates available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve -- Spinning Reserve Service
6. Operating Reserve -- Supplemental Reserve Service

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations, but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) criteria.

Control Area Service rates available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve -- Spinning Reserve Service
4. Operating Reserve -- Supplemental Reserve Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control and Dispatch Service from BPA-TBL. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control and Dispatch Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.166 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.008 per kilowatt per day

(b) Day 6 and beyond $0.005 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.48 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a, 1.b(1), and for Hourly Firm PTP Transmission Service specified in 1.b(2) shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b(2) for Hourly Non-Firm Service shall be the scheduled kilowatthours.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A of the Network Integration Rate Schedule (NT-02).

SECTION II. ANCILLARY SERVICE RATES

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources Service from BPA-TBL. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.067 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Nonfirm Service

(a) Days 1 through 5 $0.003 per kilowatt per day

(b) Day 6 and beyond $0.002 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.19 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a, 1.b(1) and for Hourly Firm PTP Transmission Service specified in 1.b(2) shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b(2) for Hourly Non-Firm Service shall be the scheduled kilowatthours.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A of the Network Integration Rate Schedule (NT-02).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA-TBL's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

SECTION II. ANCILLARY SERVICE RATES

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.30 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

SECTION II. ANCILLARY SERVICE RATES

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA-TBL. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a schedule hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TBL will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each hour) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TBL will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy taken by the Transmission Customer in a schedule hour is less than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during the that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy taken by the Transmission Customer in a schedule hour is less than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the PNW. If no adequate hourly index exists, an alternative index will be used. The index to be used will be posted on the OASIS at least 30 days prior to use for determining the BPA incremental cost and will not be changed more often than once per year unless BPA-TBL determines that the existing index is no longer a reliable price index.

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any hour of that day.

c. **Intentional Deviation**

For any hour(s) that an imbalance is determined by BPA-TBL to be an Intentional Deviation:

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

SECTION II. ANCILLARY SERVICE RATES

E. OPERATING RESERVE -- SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve -- Spinning Reserve Service from BPA-TBL and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. For a Transmission Customer's load (located inside or outside of the BPA Control Area) served by generation located in the BPA Control Area, the Transmission Customer's Spinning Reserve Requirement shall be determined consistent with applicable NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of the Transmission Customer's Spinning Reserve Requirement.

b. For energy delivered, the generator shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Spinning Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Spinning Reserve Requirement equal to the sum of:

(i) Two and a half percent (2.5%) of the hydroelectric generation dedicated to the Transmission Customer's firm load responsibility; and

(ii) Three and a half percent (3.5%) of non-hydroelectric generation dedicated to the Transmission Customer's firm load responsibility.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION II. ANCILLARY SERVICE RATES

F. OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve -- Supplemental Reserve Service from BPA-TBL and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. For a Transmission Customer's load (located inside or outside the BPA Control Area) served by generation located in the BPA Control Area, the Transmission Customer's Supplemental Reserve Requirement shall be determined consistent with applicable NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Supplemental Reserve Requirement.

b. For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA-TBL, either :

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports (see section 2.a(iii)). The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

a. The Billing Factor for Supplemental Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Supplemental Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the Transmission Customer's firm load responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the Transmission Customer's firm load responsibility, plus

(iii) Any power scheduled into the BPA Control Area that can be interrupted on ten (10) minutes' notice.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA-TBL transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.30 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TBL will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each hour) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TBL will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy delivered from the generation resource is greater than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the PNW. If no adequate hourly index exists, an alternative index will be used. The index to be used will be posted on the OASIS at least 30 days prior to use for determining the BPA incremental cost and will not be changed more often than once per year unless BPA-TBL determines that the existing index is no longer a reliable price index.

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than schedules) for any hour of that day.

c. **Intentional Deviation**

No credit is given for negative deviations (actual generation greater than schedules) for any hour(s) that the imbalance is an Intentional Deviation (as determined by BPA-TBL).

For positive deviations (actual generation less than schedules) which are determined by BPA-TBL to be Intentional Deviations, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

d. **Exemptions from Deviation Band 3**

The following resources are not subject to Deviation Band 3:

i) wind resources; and
ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than ± 1.5% or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

SECTION III. CONTROL AREA SERVICE RATES

C. OPERATING RESERVE -- SPINNING RESERVE SERVICE

Operating Reserve -- Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TBL, and such Spinning Reserve Service is not provided for under a BPA-TBL transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Spinning Reserve Requirement

b. For energy delivered, the customer shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Spinning Reserve Service is determined in accordance with applicable WECC and NWPP standards. Application of current standards establish a minimum Spinning Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the customer's firm load responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the customer's firm load responsibility.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

D. OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

Operating Reserve -- Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TBL, and such Supplemental Reserve Service is not provided for under a BPA-TBL transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards.

1. RATES

a. The rate shall not exceed 8.39 mills per kilowatthour of Supplemental Reserve Requirement

b. For energy delivered, the customer shall, as directed by BPA-TBL, either:

(i) Purchase the energy at the hourly market index price applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TBL.

2. BILLING FACTORS

a. The Billing Factor for Supplemental Reserve Service is determined in accordance with applicable WECC and NWPP guidelines. Application of current guidelines establish a minimum Supplemental Reserve Requirement equal to the sum of:

(i) Two and one half percent (2.5%) of the hydroelectric generation dedicated to the customer's firm load Responsibility, plus

(ii) Three and one half percent (3.5%) of non-hydroelectric generation dedicated to the customer's firm load responsibility, plus

(iii) Any power scheduled into the BPA Control Area that can be interrupted on ten (10) minutes' notice.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA §212 specified in section II.D of the GRSPs.

61. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

Attachment 2
Unauthorized Increase Charge (UIC) Examples

1. **<u>Reservation</u>**

The customer purchases 10 MWs of PTP for 9 days, January 29 to February 6.

<u>Unauthorized Increase (UI)</u>

On January 30, the customer schedules 15 MWs under this reservation, a UI of 5 MWs. This is the highest UI for this Reservation for the month of January.

<u>PTP rate for 9-day service (Short-Term Weekly Service)</u>

(5 days*.047) + (4 days*.035) = $0.375 per kW

<u>PTP rate for Long-Term service</u>

$1.028 per kW per month

Since the 9-day rate for short-term weekly service is less than the monthly rate for long-term service, the 9-day rate is used.

<u>UIC rate</u>

2 * .375 = $0.75 per kW

<u>UIC charge for January</u>

5,000 kW * $0.75 per kW = $3,750

2. Reservation

The customer purchases 10 MWs of IS for 40 days, January 20 to February 28.

Unauthorized Increase (UI)

On January 30, the customer schedules 15 MWs under this reservation, a UI of 5 MWs. This is the highest UI for this Reservation for the month of January.

IS rate for 40-day service (Short-Term Monthly Service)

(5 days * .054) + (35 days * .040) = $1.670 per kW

IS rate for Long-Term Service

$1.176 per kW per month

Since the 40-day rate for short-term monthly service is greater than the monthly rate for long-term service, the monthly rate for long-term service is used to calculate the UIC.

UIC rate

2 * 1.176 = $2.352 per kW

UIC charge for January

5,000 kW * $2.352 per kW = $11,760

Attachment 3
Initial Proposal Rates

RATE	$/kW/mo (except where noted)
FPT-04.1	
Main Grid	
• Distance	$0.0511/mile
• Interconnection Terminal	0.53
• Terminal	0.59
• Miscellaneous Facilities	2.91
Secondary System	
• Distance	$0.5021/mile
• Transformation	5.49
• Intermediate Terminal	2.12
• Interconnection Terminal	1.50
FPT-04.3 (FY 2005) *	
Main Grid	
• Distance	$0.0518/mile
• Interconnection Terminal	0.54
• Terminal	0.60
• Miscellaneous Facilities	2.96
Secondary System	
• Distance	$0.5095/mile
• Transformation	5.57
• Intermediate Terminal	2.15
• Interconnection Terminal	1.52
* FPT-04.3 rates will remain at FPT-02.3 levels for FY 2004, and increase by 3% (shown here) over FPT-02.3 levels for FY 2005.	
IR-04	1.261
NT-04	
• Base	1.028
• Load Shaping	0.425 *
	*(reflects 1.5% + $1M)
PTP-04	
• Long-Term	1.028
• Short-Term (per day)	
• Days 1-5	.047
• Day 6 and beyond	.035
• Hourly	2.96 mills/kWh

Attachment 3
Initial Proposal Rates (cont'd)

RATE	$/kW/mo (except where noted)
IS-04	
• Long-Term	1.176
• Short-Term (per day)	
• Days 1-5	.054
• Day 6 and beyond	.040
• Hourly	3.39 mills/kWh
IM-04	
• Long-Term	1.258
• Short-Term (per day)	
• Days 1-5	.058
• Day 6 and beyond	.042
• Hourly	3.61 mills/kWh
Utility Delivery Charge	.946
GTA Delivery Charge	.946
Unauthorized Increase Charge	• PTP Service: Not to exceed 2 times the monthly rate for Long-Term Service • NT Service: $2.056/kW/mo
ACS-04	
Scheduling	
• Long-Term	.166
• Short-Term (per day)	
• Days 1-5	.008
• Day 6 and beyond	.005
• Hourly	0.48 mills/kWh
Generation Reactive	
• Long-Term	.067
• Short-Term (per day)	
• Days 1-5	.003
• Day 6 and beyond	.002
• Hourly	0.19 mills/kWh
Regulation and Frequency Response (Ancillary & Control Area rates)	.30 mills/kWh
Operating Reserves (Ancillary & Control Area rates)	8.39 mills/kWh

Attachment 4

Open Access Transmission Tariff
Revised Attachment K

For the period October 1, 2003, through September 30, 2005, to the extent the Transmission Provider determines that redispatch of Network Resources is necessary to maintain Network Integration Transmission (NT) Service, the Transmission Provider shall implement redispatch in accordance with the provisions of this Attachment K. Attachment K addresses only circumstances in which the Tariff requires NT and Point-to-Point (PTP) uses on a constraint be reduced on a comparable basis.

1. The Transmission Provider shall not issue redispatch instructions under this Attachment K to increase ATC.

2. The BPA Power Business Line (PBL) will inform the Transmission Provider of all non-power constraints that limit the PBL's ability to redispatch generation resources. The Transmission Provider will not violate these non-power constraints unless an emergency situation leaves no other alternative for maintaining system reliability or providing safety to individuals or property. Notwithstanding any other provision of Attachment K, the protection of transmission system reliability and the safety of people and property will be the primary criteria the Transmission Provider will use in an emergency situation.

3. PBL will provide the Transmission Provider federal hydroelectric generation resource set points. The Transmission Provider may request changes to such set points. Not all changes to set points are redispatch.

4. For redispatch that occurs within the hour of delivery:

   If the Transmission Provider determines that a redispatch of federal hydro-electric projects is necessary to maintain the reliability of the FCRTS in real-time and the Transmission Provider is unable to calculate the portion of the constraint attributable to NT schedules, the Transmission Provider may redispatch the federal hydro-electric projects as necessary to relieve the constraint for the remainder of the hour and, if the event occurs twenty minutes past the hour, for the next hour also. However, the Transmission Provider must make the determination described in section 5 as soon as possible, not to exceed 100 minutes after the need for redispatch arises, and adjust the redispatch instructions accordingly.

5. For Day-ahead and Hour-ahead redispatch:

    a. The Transmission Provider will use redispatch only to manage congestion on the FCRTS that would impact NT schedules. The Transmission Provider will redispatch the system only to the extent necessary to maintain the NT schedules.

    b. The Transmission Provider will not issue any redispatch instructions until it has curtailed all non-firm schedules across the constrained path.

    c. If the Transmission Provider determines that a constraint can be relieved by redispatching federal hydro-electric projects, the Transmission Provider will determine what portion of the constraint is caused by NT schedules and what portion is caused by PTP schedules. Then the Transmission Provider will issue a redispatch instruction in an amount that will relieve the NT portion of the constraint and will curtail the PTP schedules in an amount necessary to relieve the PTP portion of the constraint.

    d. If the Transmission Provider determines that the portion of the constraint caused by NT schedules cannot be relieved by only redispatching federal hydro-electric projects, the Transmission Provider will contact the PBL schedulers and inform the PBL schedulers of the amount of NT schedule associated with the constraint. The PBL schedulers will attempt to relieve the constraint by the least cost means, including, but not limited to, purchasing alternative transmission from a third party, purchasing replacement generation from a third-party and redispatching federal generation accordingly, or requesting third party generation to decrease and using federal generation to replace the third-party generation. In making these arrangements the PBL will act as a purchasing agent for the Transmission Provider.

6. The Transmission Provider will not request redispatch for any purpose under the Tariff other than that stated herein or otherwise required by the Tariff.

Attachment 5

Business Practices and Systems Forum

BPA TBL will meet with Transmission Customers at least three times between November 2002 and September 2003 to discuss Business Practices and systems used to implement TBL's Open Access Transmission Tariff and its Transmission and Ancillary Service Rate Schedules. TBL agrees to discuss the following issues identified during TBL Rate Case Workshops held in September and October 2002:

1. TBL's Business Practices on Operating Reserves – Spinning and Supplemental Services,
2. Real Power Losses,
3. Curtailment during Real-Time, including PTP curtailment based on contract demand vs. schedules, and
4. Scheduling practices and associated systems, including wind resource scheduling.

Prior to the first meeting, TBL will draft and circulate principles to govern the meetings. TBL will post on its website the meeting location and agenda at least 10 days prior to each meeting. The first meeting will take place no later than December 13, 2002.

TBL and the Transmission Customers agree to use best efforts to ensure that the appropriate technical, and other, staff attend the meetings (either in person or by telephone conference) to facilitate meaningful discussions.

The parties agree that these meetings are designed to supplement, not revise, TBL's existing process to develop its Business Practices and systems. Further, while TBL agrees to work in good faith to discuss and address Transmission Customer concerns, TBL retains discretion to determine whether to make any changes to its Business Practices or systems as a result of the meetings. TBL will use the meetings to solicit feedback for use in developing or revising its Business Practices or systems, but is under no obligation to develop new Business Practices or systems or make any changes to existing Business Practices or systems. If TBL changes its Business Practices or systems, whether on its own or as a result of Transmission Customer input at the meetings, it will use its best efforts to implement those changes in a timely manner pursuant to TBL's established Business Practice process. The Transmission Customers retain all rights under TBL's Open Access Transmission Tariff, as it may be amended, to challenge TBL's Business Practices.

SIGNATORIES TO THE
2004 TRANSMISSION RATE CASE
SETTLEMENT AGREEMENT

Alcoa, Inc.
Avista Corp.
Avista Energy, Inc.
Bonneville Power Administration Power Business Line
Clallam County Public Utility District
Clark Public Utilities
Columbia Falls Aluminum Company, LLC
Town of Eatonville
City of Ellensburg
Emerald People's Utility District
Fairchild Air Force Base 92nd Contracting Squadron
Golden Northwest Aluminum, Inc.
Idaho Energy Authority
- *Signing for:*
- City of Burley
- City of Declo
- East End Mutual Electric Co., Ltd.
- Farmer's Electric Company
- City of Heyburn
- Idaho County Light & Power Cooperative, Inc.
- Idaho Falls Power
- Lower Valley Energy, Inc.
- City of Minidoka
- Riverside Electric Co., Ltd
- City of Rupert
- City of Soda Springs
- South Side Electric, Inc.
- United Electric Cooperative, Inc.

Idaho Power, Inc.
Industrial Customers of Northwest Utilities
Kittitas Public Utility District
City of Klamath Falls
Lakeview Light & Power
Lewis County Public Utility District
Mason Public Utility District No. 1
Mason County Public Utility District No. 3
City of Milton

Northwest Requirement Utilities

Signing for:

City of Ashland

Benton REA

Big Bend Electric Cooperative

Canby Utility

City of Cascade Locks

Central Lincoln Public Utility District

Columbia Basin Electric Cooperative

Columbia Power Cooperative

Columbia REA

Columbia River Public Utility District

East End Mutual Electric Company

Ferry County Public Utility District #1

Flathead Electric Cooperative

City of Forest Grove

Harney Electric Cooperative

Hood River Electric Cooperative

City of Idaho Falls

Inland Power & Light

Klickitat County Public Utility District

McMinnville Water & Light

Midstate Electric Cooperative

Modern Electric Water Company

City of Monmouth

Nespelem Valley Cooperative

Northern Wasco County Public Utility District

Orcas Power & Light Cooperative

Oregon Trail Electric Cooperative

City of Richland

City of Rupert

Salem Electric

Skamania County Public Utility District

Surprise Valley Electrification Corp.

Tanner Electric Cooperative

Tillamook People's Public Utility District

United Electric Cooperative

Vera Water & Power

Wasco Electric Cooperative

Wells Rural Electric

Western Montana Electric G&T Cooperative

Northwestern Energy

Northwestern Wind Power, LLC

OHOP Mutual Light Company

PacifiCorp, Inc.

PacifiCorp Power Marketing, Inc.

Pacific County Public Utility District No. 2

Pacific Northwest Generating Cooperative
Signing for:
Blachly-Lane Electric Cooperative
Clearwater Power Company
Consumers Power Inc.
Fall River Rural Electric Cooperative
Okanogan County Electric Cooperative
Umatilla Electric Cooperative
West Oregon Electric Cooperative
Central Electric Cooperative
Coos-Curry Electric Cooperative
Douglas Electric Cooperative
Lane Electric Cooperative
Northern Lights, Inc.
Salmon River
Raft River Rural Electric Cooperative
Parkland Light & Water Company
Peninsula Light Company
City of Port Angeles
Portland General Electric
Power Resource Managers, LLP
Signing for:
Benton Public Utility District
Franklin Public Utility District
Grays Harbor Public Utility District
Powerex Corp.
Public Generating Pool
Signing for:
Cowlitz County Public Utility District No. 1
Douglas County Public Utility District No. 1
Grant County Public Utility District No. 2
Pend Oreille County Public Utility District No. 1
City of Seattle, City Light Department
Public Power Council
Puget Sound Energy, Inc.
Renewable Northwest Project
Snohomish County Public Utility District
Town of Steilacoom
Tacoma Public Utilities
TransAlta Energy Marketing
Wahkiakum Public Utility District

Bonneville Power Administration
PO Box 3621 Portland, Oregon 97208-3621
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