TRANSMISSION RATE DESIGN

STUDY

PREPARED BY

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

June 1996

WP-96-FS-BPA-06

TRANSMISSION RATE DESIGN STUDY

TABLE OF CONTENTS

LIST OF TABLES

COMMONLY USED ACRONYMS

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

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

PNW	Pacific Northwest
POD	Point of Delivery
PSW	Pacific Southwest
PURPA	Public Utilities Regulatory Policies Act
PUD	Public or Peoples' Utility District
RAM	Rate Analysis Model (computer model)
REVEST	Revenue Estimate (computer program)
ROD	Record of Decision
RP	Reserve Power (rate)
RPSA	Residential Purchase and Sale Agreement
SAM	System Analysis Model
SI	Special Industrial Power (rate)
SPM	Supply Pricing Model (computer program)
SPOM	Surplus Power-Open Market
SS	Share-the-Savings Energy (rate)
TGT	Townsend-Garrison Transmission (rate)
UFT	Use of Facilities Transmission (rate)
USBR	United States Bureau of Reclamation
VI	Variable Industrial Power (rate)
VOR	Value of Reserves
WNP	Washington Public Power Supply System (Nuclear) Project
WPPSS	Washington Public Power Supply System
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WSCC	Western Systems Coordinating Council

1. INTRODUCTION

1.1 Purpose

The Transmission Rate Design Study (TRDS) presents an overview of Bonneville Power Administration's (BPA’ s) rate design process for developing the proposed transmission rates. In prior BPA rate proceedings, transmission cost allocation and design of the transmission component of power rates was performed in the Wholesale Power Rate Development Study (WPRDS), while design of wheeling (transmission of non-BPA power) rates occurred in the TRDS. For the first time, all transmission rate development is performed in the TRDS. The end result of the TRDS is the transmission rate schedules and associated General Rate Schedule Provisions that are published in the Wholesale Power and Transmission Rate Schedules (WP-96-A-02, Appendix). A summary of the proposed transmission rates is shown on Table 19.

Consistent with the power rates, five-year transmission rates have been developed. The five year rate period is Fiscal Years (FYs) 1997 through 2001. (A fiscal year runs October 1 to September 30.) The transmission rate for BPA power sales has been unbundled from the power rate. Customers purchasing power under 1981 Power Sales Contracts (1981 Contracts) at the Priority Firm, Industrial Firm, and New Resource Firm rate will pay for associated transmission service under the new NTP rate schedule unless they choose to convert to service under one of the open access tariffs. Customers purchasing power under 1996 Power Sales Contraccts (1996 Contracts) must take transmission service under the new open-access Network Integration (NT) or Point-to-Point (PTP) tariffs at the NT or PTP rate, respectively. DSIs taking service under Block sale 1996 Contracts pay the PTP rate. The NT and PTP rates are also available for transmission of non-Federal power.

The overall level and design of transmission rates is governed by BPA's statutory obligations, commitment to comparability, the Transmission Settlement Agreement, contractual arrangements, the transmission revenue requirement, load forecasts, and the consideration of revenue stability, rate continuity, and ease of administration. The TRDS first briefly discusses some of these factors and then discusses the methodology used in developing transmission rates.

1.2 Overview of the Basis for Rate Development

Factors influencing the level and design of transmission rates are statutory obligations, comparability, contractual arrangements, cost studies, and load forecasts.

1.2.1 Statutes. In accordance with section 4 of the Federal Columbia River Transmission System Act (Transmission System Act), BPA constructs, operates, and maintains the Federal Columbia River Transmission System (FCRTS) to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide interregional transmission facilities; and (d) maintain the electrical stability and reliability of the Federal system. 16 U.S.C. §838b.

BPA's transmission rates are established in accordance with sections 9 and 10 of the Transmission System Act (16 U.S.C. §§838g and h), section 5 of the Flood Control Act of 1944 (16 U.S.C. §825s), and the provisions of section 7 of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act). 16 U.S.C. §839e. Section 7(a)(2)(C) of the Northwest Power Act requires that BPA ". . . equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system." 16 U.S.C. §839e(a)(2)(C). Some of BPA's transmission rates are also prepared in accordance with section 212(i)(1)(b)(ii) of the Federal Power Act, as amended by the Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776. 16 U.S.C. §824k(i)(1)(B)(ii).

1.2.2 Comparability. In the Energy Policy Act of 1992 (EPA' 92), Congress approved amendments to sections 211 and 212 of the Federal Power Act that allow the Federal Energy Regulatory Commission (FERC) to order access to utility transmission systems, including the FCRTS. 16 U.S.C. §§824j and 824k(i)(1). Since passage of EPA' 92, FERC developed standards for providing comparable access to transmission services. *American Electric Power Service Corp.*, 64 F.E.R.C. ¶61,279 (1993), *reh'g granted*, 67 F.E.R.C. ¶61,168, *clarified*, 67 F.E.R.C. ¶61,317 (1994). "Comparable" refers to FERC' s new standard for determining whether access to transmission services is unduly discriminatory or anticompetitive. The analysis focuses on a determination of whether the transmitting utility is offering third parties access on the same or comparable terms and conditions, and at the same or comparable rates that the utility uses for itself. *Id*. at 61,490. FERC also issued a transmission pricing policy as a further action to address a more competitive electric industry. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 59 Fed. Reg. ¶55,301, FERC Stats. & Regs. ¶31,005 (1994) (Transmission Pricing Policy). *See* also 69 F.E.R.C. ¶61,086 (1994). The Transmission Pricing Policy is based on the premise that access to transmission services at comparable prices is critical to the development of competitive wholesale power markets.

On March 29, 1995, FERC issued a notice of proposed rulemaking: *Promoting Wholesale Competition Through Open Access Non-discrimination Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking*. 60 Fed. Reg. 61,351, FERC Stats. & Regs. ¶32,514 (1995). (NOPR) In this NOPR, FERC proposed to require all transmission-owning public utilities subject to FERC jurisdiction to file generic open access tariffs and to take transmission service, including ancillary services, for their own new wholesale electric sales and purchases under the open access tariffs. The NOPR also included a supplemental proposed rule to permit the recovery of stranded costs associated with requiring open access tariffs. On April 24, 1996, FERC issued its final rule *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21,540, FERC Stats. & Regs. ¶31,036 (1996) (Order 888). In Order 888, FERC requires all transmission-owning public utilities subject to FERC jurisdiction to file non-discriminatory open access transmission tariffs. Order 888 also requires jurisdictional utilities to take transmission service, including ancillary services, for their own new wholesale electric sales and purchases under the open access tariffs. *Id*. at 21,552. While Order 888, by its terms, does not apply directly to BPA, FERC declared its intention to apply the policies announced therein 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 21,573. Order 888, however, was issued in the final stages of the 1996 rate case. BPA was, therefore, guided throughout the 1996 rate case to arrive at rates for transmission on the FCRTS that would conform to the comparability policies announced in the Transmission Pricing Policy, and the rates, terms, and conditions of the open access tariffs provided in the NOPR.

To implement comparability principles, BPA is proposing a construct under which transmission rates and tariffs will apply individually to each PF, IP and NR power sale. This will ensure compliance with the principle of transparency for these sales. For BPA' s remaining business, the power busines (also referred to as "GenCo") will have the option of purchasing PTP service under the same rates, terms and conditions as other wheeling customers and bundling that transmission with power products in a flexible manner.

A second key aspect of the construct is the use of contract demand or its equivalent for cost allocators. Until the 1996 rate case, BPA allocated costs using one method, 12 coincidental peaks, while calculating rates based on non-coincidental demand billing determinants for power customers and contract demand and energy for wheeling customers. However, in the 1996 rate case, BPA uses contract demand or its equivalent for allocation factors which aids in designing rates that are the same for power customers and wheeling customers.

A third key aspect of the rate construct is a major revision of the segmentation of BPA’ s transmission system. The former Fringe segment has been eliminated, with the BPA transmission facilities portion of the segment now included in the Network segment. The DSI Delivery segment includes facilities at and below 34.5 kV; Utility Delivery includes facilities below 34.5 kV. The new Delivery Charge applies to all power--Federal and non-Federal--delivered over these facilities. Facilities at higher voltages are now segmented to the Network.

In a process concurrent with the 1996 rate case, BPA proposed terms and conditions of general applicability for Network Integration and Point-to-Point transmission service. BPA’ s tariffs were modeled on the tariffs in the FERC NOPR. In conjunction with the proposed open access transmission services, BPA developed new rate schedules (Network Integration (NT), Point-to-Point (PTP), Reserved Nonfirm (RNF), and Montana Intertie (IM) rates) and revised other rate schedules (Southern Intertie (IS) and Energy Transmission (ET) rates) to correspond to the new tariffs. BPA is also proposing a new rate schedule, the Ancillary Products and Services (APS-96) rate that will allow it to sell ancillary services. The APS rate is discussed in the WPRDS (WP-96-FS-BPA-05). In addition, a new transmission rate schedule, NTP, for the transmission associated with PF power purchased under 1981 Contracts reflects the unbundling of transmission cost from power cost. BPA also has rates for existing firm Network wheeling contracts: the Integration of Resources (IR) rate and the Formula Power Transmission (FPT) rate.

1.2.3 Settlement. In the month following cross examination of witnesses, BPA and representatives of the active parties in the 1996 rate case reached a settlement of all issues regarding BPA’ s transmission rate proposal and the terms and conditions proposal contained in BPA’ s Network and Point-to-Point tariffs. The settlement is contained in the Transmission Rates and Terms and Conditions Settlement Agreement (Transmission Settlement Agreement or Settlement Agreement).

WP-96-A-02, Attachment 1. Representatives for a majority of BPA’ s existing power and wheeling customers joined the Transmission Settlement Agreement. Parties participating in the Transmission Settlement Agreement ranged from full and partial wholesale requirements power customers to transmission-only customers, including competing power suppliers. The Settlement Agreement for the terms and conditions, and for the rates reflects the provisions of the NOPR, as adapted to Pacific Northwest (PNW) practices. BPA and the parties relied heavily on the NOPR; Orders 888 and 889 were not available until after the Transmission Settlement Agreement was executed. The settling parties intend that the Transmission Settlement Agreement will settle issues relating to all of BPA’ s transmission rates, and terms and conditions for open access transmission service for the five year period from October 1, 1996 through September 30, 2001. The Administrator is adopting the Settlement Agreement for BPA’ s final rate proposal. The rate development and rate schedules described herein reflect the provisions of the Settlement Agreement. Some of the provisions of the Transmission Settlement Agreement are:

- the IR rate will not exceed $1.001/kW/month; and the PTP rate, NT Base Charge, and NTP Base Charge will equal the IR rate;
- the overall increase in total revenues for FPT service will be no more than 13.5% over revenues from current FPT rates;
- the Utility Delivery Charge shall be $0.75/kW/month assessed on the customer’ s demand on the facilities;
- the Utility Delivery segment shall only include facilities below 34.5 kV;
- General Transfer Agreement cost shall be allocated entirely to power rates and Delivery segments;
- the PTP rate schedule shall incorporate the “no points of integration” proposal for calculation of the PTP billing factor;
- Northern Intertie facililties shall be included in the Network segment, and the Northern Intertie rate schedule shall be eliminated.

1.2.4 Contractual Arrangements. BPA and its wheeling customers enter into transmission agreements that can affect the transmission rates charged customers. Transmission agreements negotiated prior to the Transmission System Act reflect conditions and policies prevalent at the time of negotiation. Some agreements, for example, to which the Formula Power Transmission (FPT) rate applies, specify that transmission rates can be changed annually, while other agreements limit rate adjustments to once every 3 years. In addition, contractual provisions in some agreements stipulate methods for determining transmission rates.

2. TRANSMISSION RATE METHODOLOGY

2.1 Rate Construct

One aspect of BPA's rate construct is to set the PTP rate, the IR rate, and the Base Charge for the NT and NTP rates equal to each other. The FPT rate is not included in this construct because of its different rate design. In addition, the Network allocation factors are annual contract demands or their equivalent. For customers without contract demands (NT rate customers and 1981 Power Sales Contract customers under the NTP rate), the sum of their forecasted annual noncoincidental peaks is used as the contract demand equivalent.

The portion of the NT/NTP allocation factor that represents the difference between the classes' coincidental peak demand and their annual noncoincidental peaks is the basis for the Transmission Load Shaping allocation factor; the remaining portion of the NT/NTP allocation factor is included in the determination of the Base Charge. The NT/NTP Transmission Load Shaping allocation factor is also adjusted for transmission losses.

In the calculation of Network and Intertie rates, all uses of the transmission system are identified. Previously, costs were allocated to loads only; now, costs are allocated to all uses of the transmission system including storage and other coordination transactions. Firm PTP contract demands are assigned to BPA's existing surplus sales and exchanges and forecasted Firm Products and Services (FPS) rate transactions. The full flexibilities of the PTP service are assumed in modelling the BPA power business' nonfirm uses of the transmission system. To the extent that the firm PTP demands are available, nonfirm energy sales and other nonfirm uses of the transmission system are assumed to use the PTP demands at no additional cost.

2.2 Transmission Cost.

BPA determines a transmission revenue requirement that is divided among identified segments of the FCRTS. The Segmentation Study (WP-96-FS-BPA-03) identifies the transmission facilities and associated investment for each transmission segment and, thus, provides a basis for segmenting the revenue requirement. The Revenue Requirement Study (WP-96-FS-BPA-02) determines the test period revenue requirement for transmission, and from that, the revenue requirement for each transmission segment.

2.2.1 Segmentation Study. BPA operates and maintains the FCRTS to provide various transmission services throughout the Pacific Northwest (PNW) region. Because many services do not require the use of the entire system, the Segmentation Study categorizes the facilities of the FCRTS according to the types of services they provide. The Segmentation Study produces the segmented historical FCRTS investment base and the segmented averages of the last 3 years' actual operations and maintenance (O&M) expenses. This provides the basis for segmenting the transmission revenue requirements used to develop rates.

BPA has revised its segmentation from the method used in previous rate cases. In previous rate cases, BPA identified nine segments; in the current rate proposal, the Fringe, IOU Delivery, and Northern Intertie segments have been combined with other segments. The FCRTS is now divided into six segments: (1) Network (or, Integrated Network); (2) Southern Intertie; (3) Eastern Intertie; (4) Generation-Integration; (5) Utility Delivery; and (6) Direct Service Industry (DSI) Delivery. In addition, the Utility and DSI Delivery segments are now more narrowly defined. The Utility Delivery segment includes facilities with voltages below 34.5 kV; the DSI Delivery segment includes facilities with voltages at or below 34.5 kV. Higher voltage facilities are now reclassified as Network.

Previously, the Fringe segment cost was composed of the cost of a portion of BPA transmission facilities, used only to serve Federal power, and a large part of the "wheeling budget," including the cost of the General Transfer Agreements (GTA). Under GTAs, transmission-owning utilities provide bulk power transfers to BPA wholesale power customers. The BPA transmission facilities portion of the Fringe is now in the Network; the wheeling budget costs are divided between Network and Delivery segments based on voltage level--facilities with voltages equal to or higher than 34.5 kV are now segmented to Network; those below 34.5 kV are segmented to Delivery. (In a later step, the GTA costs in the Network are subtracted out and allocated to the BPA power business. *See* section 2.2.3.) In addition, the current IOU Delivery and Northern Intertie segments are rolled into the Network.

2.2.2 Revenue Requirement Study. The Revenue Requirement Study is prepared consistent with BPA's statutory obligation to set rates to recover, in accordance with sound business principles, all costs of acquiring, conserving, and transmitting electric power, including the repayment of the Federal investment in the Federal Columbia River Power System (FCRPS) over a reasonable number of years, and all other FCRPS costs. In compliance with the FERC order dated January 27, 1984 (26 F.E.R.C. ¶61,096 (1984)), BPA determines separate revenue requirements for the generation and transmission functions of the FCRPS.

Each revenue requirement consists of two parts. First, power repayment studies are prepared for the generation and transmission functions to determine the projected annual interest expense and amortization payments on the Federal investment. These studies are conducted for the rate test period and extend through the repayment period. Second, projections of annual operating expenses of the FCRPS are compiled and, with the planned net revenues determined by the Administrator, are functionalized into the generation and transmission functions of the FCRPS.

The GTA portion of the wheeling budget expense is computed in the TRDS by multiplying the transferors' charges times forecasted BPA GenCo sales subject to those charges. Transfer rates to BPA are assumed to grow at 2% per year; UFT-type charges are included as well. The forecast of GTA costs is shown in Appendix C, column M.

Thus, BPA's revenue requirements are set for each function at levels sufficient to meet its share of the annual operating expenses of the FCRPS, to cover interest expense, to make annual amortization payments on the Federal investment as determined by the corresponding power repayment studies, and to recover planned net revenues. The segmented transmission revenue requirement is shown on Table 1.

2.2.3 Revenue Credits and Direct Cost Reassignments. The segmented transmission revenue requirement is adjusted for revenue credits and cost reassignments to arrive a the segment costs used to set the adjustable transmission rates (referred to in the TRDS tables as "rate development costs"). First, expected revenues from fourteen revenue credits are identified and segmented in Table 2. Transmission revenue credits are transmission revenues from sources other than the general transmission rates developed in the TRDS. These credits are subtracted from the appropriate segment revenue requirement in Table 3 before costs are allocated.

The net cost of the Eastern Intertie is allocated on Table 3. This net cost represents the Eastern Intertie revenue requirement less the expected revenues from the Townsend-Garrison Transmission rate. The net cost is allocated to the remaining segments based on net plant in each segment.

Table 3 also shows the resegmentation of the DSI Delivery cost underrecovery. The DSIs will pay for DSI Delivery facilities through UFT charges. Appendix I documents the forecasted DSI revenues from UFT charges. The difference between the forecasted revenues and segment cost ($4.8 million for five years) is assigned to the Network. In addition, Table 3 shows the reassignment of the Utility Delivery cost underrecovery and the Network portion of GTA costs to the BPA power business. The underrecovery of Utility Delivery costs represents the difference between an average segment cost of $12.97/kW/year and the proposed Utility delivery Charge of $9.00/kW/year provided in the Settlement Agreement. *See* Table 18. Also, as specified in the Settlement Agreement, GTA costs are excluded from Network transmission rates. Therefore, the portion of GTA costs in the Network segment (*See* section 2.2.1) are reassigned to the BPA power business in Table 3.

Finally, the Generation-Integration segment cost is associated with transmission facilities that integrate Federal resources to the Network. These costs are assigned wholly to power customers and recovered through power rate charges. Table 3, column A shows the adjusted Generation-Integration cost that is assigned to the BPA power business. (*See* the WPRDS, WP-96-FS-BPA-05, for further discussion of the treatment of Generation-Integration and other direct assignment transmission costs in power rate development.)

2.3. Transmission Loads

2.3.1 Network Demands. BPA proposes to offer five firm Network transmission services and associated rates: Integration of Resources (IR); Formula Power Transmission (FPT); Network Integration under 1981 power sales contracts (NTP); Network Integration (NT) under the NT Tariff; and Point-to-Point (PTP). Network allocation factors for the IR, FPT, and PTP rates are forecasted contract demands; and for the NT and NTP rates are forecasted annual noncoincidental demands (NCD) as a contract demand equivalent. With the exception of the FPT rate, the rates include the same Base Charge. The NT and NTP rates also include a Transmission Load Shaping Charge. The Base Charge is calculated using the Network costs allocated to IR and PTP, and the portion of the Network cost allocated to the NT/NTP monthly coincidental demands. The Transmission Load Shaping Charge is developed from the allocated Network costs using the difference between the NT/NTP Base Charge billing determinants (monthly coincidental demands) and the contract demand equivalent (NCDs). The allocation factor for Transmission Load Shaping includes a 1.6% losses adjustment; thus, the transmission of losses for NT and NTP service are paid through the Transmission Load Shaping Charge.

BPA power customers will use the NTP, NT, or PTP rate for the transmission service associated with their BPA power purchases. NTP is available for the transmission of PF, IP, and NR power sold under 1981 power sales contracts; NT and PTP are available for the transmission of Federal and non-Federal power for 1996 Contracts and, with a contract amendment, for 1981 Contracts. Benton County PUD, Franklin County PUD, and Grays Harbor PUD are forecasted to take NT service. All other PF load is assumed to take NTP service. No PF customers are assumed to take PTP service. The monthly 12 CP allocation factors for the non-generating customer group, shown on Table 6, lines 6.1-6.2, are calculated using the coincidence factors calculated in Appendix G and shown on Table 5. These coincidence factors are based on 4 years of actual data --October 1990 through September 1994 --and are applied to forecasted energy loads (Table 4). The remaining CRCs under the PF rate are forecast to take service at the NTP rate. Their Base Charge allocator is the class' s average of 12 NCDs shown on Table 6. *See* Appendix B.

The allocation factor for the Transmission Load Shaping Charge in the NT and NTP rate schedules is based on forecasts for the entire PF class. The Transmission Load Shaping allocation factor (Table 6, line 6.4) equals the load shown on Table 4, line 4.4 (the difference between the annual contract demand equivalent and the 12 CP Base Charge allocation factor), plus losses on the contract demand equivalent. *See* Appendix B, B-36, for the calculation of the Transmission Load Shaping allocation factor.

BPA' s forecast assumes that the entire class of DSIs will take service at the PTP rate. The 1996 Contract that most Direct Service Industrial customers (DSIs) executed will use PTP transmission service. DSIs under 1981 Contracts are assumed to purchase transmission service under the NTP rate. However, the NTP rate for DSIs is equivalent, for ratemaking purposes, to the PTP rate (the NTP rate for DSIs is the Base Charge only, which equals the PTP rate).

In addition, BPA is assigning the PTP rate to its own third-party sales. Transactions with PSW entities are combined into a single, consolidated PTP demand because they all share the same Network POD. For BPA sales, only the PODs are relevant under the proposed "no POI" billing factor for the PTP rate. *See* WP-96-A-02, at 430-432.

FPT and IR contract demands are forecasted using the current and expected contract demands. *See* section 2.3.2., Wheeling Load Forecast. BPA is forecasting that wheeling customers will continue their current FPT and IR contracts. In addition, Grays Harbor PUD is forecasted to terminate its FPT contract for the wheeling of Centralia and take NT service covering all of its firm Network needs.

Table 4 shows the forecasted firm loads for the IP class and IR and FPT wheeling classes. Since these loads represent annual contract demands, they are also the allocation factors shown on Table 6. BPA's PTP loads on Table 4 are shown as the average of 12 NCDs; the annual contract demand equivalent is determined in Appendix B and shown on Table 6.

2.3.2 Wheeling Load Forecast. The TRDS develops demand and energy forecasts of wheeling loads (non-Federal power using BPA's transmission system) for the rate period. The wheeling load forecast is shown on four tables in Appendix A. Transmission Demands shown in Appendix A, Table 1, are forecast for the Network and the Southern Intertie. Demand forecasts are based on Transmission Demands in firm wheeling contracts. Total Network wheeling demand is used to calculate the FPT and IR rates. Total firm demands on the Southern Intertie are used, along with firm BPA demands, to calculate the firm Southern Intertie (IS) rate.

To determine the amount of non-Federal energy on the FCRTS, wheeling loads are forecast for four services: (1) firm Southern Intertie; (2) nonfirm Southern Intertie; (3) Energy Transmission; and (4) firm Network. Since Intertie service requires use of Network facilities, all four of these forecasts are needed to determine total non-Federal Network loads.

Separate forecasts of firm and nonfirm wheeling are developed. Total firm wheeling is the sum of the wheeling energy forecast for each resource or wheeling arrangement; total nonfirm wheeling is wheeling energy forecast at the utility level. Appendix A, Tables 2 and 3, show the projected energy use of each firm arrangement for transmission. Appendix A, Table 4, presents nonfirm wheeling projections:

Energy forecasts of firm wheeling of specific resources are developed from three sources: (1) two statistical equations relating firm wheeling to pertinent causal variables such as transmission demand, projected maintenance, and system load; (2) estimates provided by the purchasing utility; and (3) utility submittals of resource operations to the NWPP Operating Program. The statistical equations are unchanged from the 1987 TRDS. *See* WP-87-FS-BPA-07, Appendix C, equations 1 and 2. Energy forecasts for nonfirm wheeling of imports from Canada, sales to the PSW, and intra-regional nonfirm transactions reflect FY 1991-FY 1995 averages by company. Appendix A, Table 4, shows these forecasts aggregated by rate schedule for the company paying transmission. Forecasted ET wheeling for customers with IR contracts are amounts assumed in excess of their respective IR demands. Eugene Water and Electric Board and Snohomish PUD are forecast assuming 95% of their nonfirm wheeling fits within their IR demands; Portland General Electric, Puget Sound Power & Light, and Seattle City Light fit 90%; Washington Water Power fits 75%, and Montana Power Company fits 50% of its nonfirm Network needs within their IR demands. Similarly, the IS nonfirm wheeling forecast excludes amounts from the historical forecast base likely to be scheduled under Non-Federal Participation (NFP) rights. Three-fourths of Puget's and Snohomish's nonfirm PSW Intertie loads fit within their NFP demands; one half of Pacificorp's and Seattle's; and one fourth of Tacoma City Light's are assumed to be under NFP. *See* Appendix A, Table 4, footnote 2.

2.3.3 Network Energy Loads.

Network energy loads are needed to calculate the ET rate. Firm loads for the classes of service shown in Table 6 are expressed in energy terms in Table 8. Total Network firm and nonfirm transmission loads are shown in Table 8. Table 7 shows the categories and forecasts of nonfirm transmission loads for Federal and non-Federal power.

The forecast for PF and DSI customers is developed in the Loads and Resources Study. *See* WP-96-FS-BPA-01. BPA nonfirm energy sales are forecast in the Nonfirm Revenue Analysis Program (NFRAP). *See* WP-96-FS-BPA-05A. Energy forecasts for BPA third-party sales are based on amounts specified in contracts, assuming the power sales mode for sales/exchanges. Energy forecasts for capacity/energy exchanges include deliveries, returns, and exchange energy. Federal uses of the transmission system for other than immediate sales for storage and Pacific Northwest Coordination Agreement (PNCA) deliveries are included as nonfirm transmission uses (Table 7). These transmission system uses represent transactions with off-system customers not included in the BPA GenCo power sales shown in Tables 6 and 7. These uses are based on five years of historical data, FY 91 through FY 95. Appendix D discusses the Federal nonfirm transmission forecast.

Forecasts of non-Federal energy under the FPT, IR, and ET rates are developed in Appendix A, Tables 2 through 4. Non-Federal energy using the transmission system must be forecast separately for IR customers because the ET rate, although developed on all loads, does not apply to IR or PTP wheeling within contract demand.

2.3.4 Utility Delivery Loads. The billing determinants for the Utility Delivery Charge are developed by point of delivery. The Delivery Charge is applicable to loads being served directly or through GTAs below the 34.5 kV level of service. Appendix C shows the development of the Delivery billing determinant. The Appendix shows the apportionment of the forecasted energy shown in column J (and in aggregate, in Table 4) over points of delivery by customer according to FY 1993 sales. The point-level forecast shown in Appendix C includes updated information on new and obsolete points provided by field and System Engineering staff. Column E indicates whether the point of delivery is included in the Utility Delivery ("UD") charge billing determinant totals (Appendix C, page 18, and Table 18).

2.3.5 Southern Intertie Loads. The TRDS forecasts eight different uses of the Southern Intertie: (1) BPA power purchases; (2) BPA exchanges; (3) BPA firm power contract sales; (4) BPA nonfirm energy sales; (5) Storage Deliveries; (6) Storage Returns; (7) nonfirm wheeling; and (8) firm wheeling. BPA's forecast of power purchases, exchanges, and contract sales is shown on Table 6. BPA nonfirm energy sales are forecast in the NFRAP and shown in Table 7; generation for storage using the Southern Intertie is also shown in Table 7. Table 7, line 7.15, indicates that although BPA stores in the PSW (line 7.12), it provided no storage for PSW entities from FY 91 through FY 95. Firm and nonfirm wheeling is forecast in the wheeling load forecast. *See* section 2.3.2., above.

2.3.6 BPA GenCo's Nonfirm Transmission Forecast. BPA's unused firm PTP and IS demands shown in Table 6 are available for nonfirm transmission at no additional cost. Over fifty percent of BPA GenCo's forecasted nonfirm use of the Network and twenty percent of its forecasted nonfirm use of the Southern Intertie is estimated to fit within firm demands. Amounts in excess of demands which are subject to the ET and the IS nonfirm rates are shown in Table 7, lines 7.30 through 7.35. An analysis of historical hourly loads is used to estimate amounts in excess of demands. These amounts are based on estimates of total hourly schedules, firm and nonfirm, minus PTP or IS firm demands for all hours that total forecasted schedules exceeded demands. Forecast of nonfirm sales to the PNW and PSW from NFRAP are combined with estimates of forecasted firm wheeling and historic needs for storage and PNCA deliveries to produce the forecast of total BPA GenCo hourly schedules. Appendix D describes this analysis further.

2.4 Network Cost Adjustment and Allocation

The segmented transmission revenue requirement is allocated based on relative use between Federal and non-Federal power utilizing the FCRTS. Network costs are allocated among firm Network rates, as in previous rate cases. Adjustments to Network costs are made before rate charges are calculated. *See* Table 3. The hourly nonfirm ET rate is not allocated costs, but is developed over all uses and applied equally to Federal and non-Federal uses.

2.4.1 Adjustment for ET Revenues. Transmission costs are not allocated to nonfirm uses of the Network. Instead, revenues from the ET hourly nonfirm transmission rate for Federal and non-Federal use are forecasted and credited against Network costs. *See* Table 10. BPA has included downward flexibility in its nonfirm transmission rates for the first time. Average revenues from the ET rate are forecast to be 0.25 mills/kWh beneath the published cap to reflect the rate's downward flexibility. Annual ET revenues of $37.3 million are subtracted from Network rate development costs (Table 10) prior to allocating Network cost to firm classes of service.

2.4.2 Network Cost Allocation. Network costs adjusted for ET revenues are allocated to the firm rate classes using forecasted contract demands as allocation factors for IR, FPT, and PTP and forecasted annual noncoincidental demands (NCDs) as a contract demand equivalent for NT and NTP. Table 11 is a summary of the cost allocations. Although FPT is allocated costs based on contract demands like the other firm Network rates, its effective allocation is determined by the Transmission Settlement Agreement provision that overall FPT revenues are not to exceed 13.5% from current FPT-95.1/FPT-95.3 rates.

2.5 Rate Calculations

After calculating the ET rate and crediting Network costs with excess revenues from ET, the firm Network rates are calculated. The FPT rate is calculated, with the revenue underrecovery assigned to the other firm Network classes. The remaining Network rates, the IR rate, PTP rate, and NT/NTP Base Charge, which are all equal, and the NT/NTP Transmission Load Shaping Charge, are then calculated.

The firm and hourly nonfirm Southern Intertie (IS) rates are based on total Southern Intertie cost and all IS energy use. The load factor associated with all firm IS demands is applied to the average IS cost to calculate the firm IS rate. The Montana Intertie (IM) rates are based on BPA's annual cost under the TGT rate, and the capacity of BPA's share of the facility.

2.5.1 Energy Transmission Rate Calculation. The calculation of the ET rate for hourly nonfirm service is shown on Table 8. The ET rate equals the total Network cost from Table 1 ($403 million per year) divided by total forecasted energy use on the Network (159,791 MW per year). This rate, 2.52 mills per kWh, is the ET nonfirm transmission rate cap.

2.5.2 FPT Rate Calculations. The first step in calculating the FPT rate is to develop an unconstrained rate shown on Table 16 by dividing subsegmented Network costs by subsegmented regional power flows. This rate is then constrained so the average overall FPT rate increase and the average increase to Pacificorp doees not exceed 13.5% consistent with the Transmission Settlement Agreement. This is accomplished by developing a uniform constaining ratio and applying it to each FPT rate component.

2.5.2.1 Subsegmentation of Network Facilities. Facilities in the Network segment are divided into two major subsegments --the Main Grid and the Secondary System. Facilities operated at 500 kV, 345 kV, and 230 kV constitute the Main Grid. The Secondary System is comprised primarily of facilities at voltages between 69 kV up to, but not including, 230 kV. The subsegmentation analysis excludes the cost of 34.5 kV facilities which are included in the Network for this rate case. The Main Grid and Secondary System subsegments are further divided into groups of like facilities, based on the function they perform. These components are listed in Table 13, which shows the cost associated with each type of facility. The sum of the Main Grid and Secondary System facility costs equals the Network revenue requirement exclusive of the costs of 34.5 kV facilities. Facility costs in Table 13 are net of revenue credits and other adjustments shown in Table 3 as well as ET excess revenue credits.

2.5.2.2 <u>Power Flow Analysis</u>. The amount of power flowing through Network facilities is determined from a power flow study made for the winter peak hour of the test period. The power flow used for this rate proposal is a simulation of January 1997 peak load conditions.

Assumptions for this power flow study are consistent with assumptions used in past rate filings. Loads and resources are based on BPA's "1996 Pacific Northwest Loads and Resources Study" published in December 1995. Individual load forecasts for public agencies and DSIs, developed by the customers in conjunction with BPA, are used. The forecasts for IOUs and large generating public utilities are provided by the utilities. All DSI loads are included. Updated load and generation forecasts are incorporated if available.

The power flow study incorporates firm interchange schedules between other regions. All large thermal generation scheduled to be available is assumed to be operating, and hydro generation forecasts assumes approximately median water conditions. The transmission system is operated as planned, as of 1997, with all lines in service.

The analysis of the power flow is made by examining the line and transformer flows at each substation in the Network segment and using power flow summaries of losses and MW-miles. A summary of the results is shown in Table 14.

2.5.2.3 <u>Calculation of the FPT Rate Components</u>. The calculation of the FPT rate components is summarized in Table 16. The FPT rate is developed in two steps. First, the FPT component costs are divided by the peak power flows, Federal and non-Federal, over those components. (*See* Table 16, Columns A-D.) The result of this calculation is shown in Column D of Table 16 and is referred to as the "Unconstrained Rate Component."

Second, the unconstrained FPT rate components are modified to produce the final FPT rate charges. They are multiplied by the constraining ratio to produce an overall increase from existing FPT rate levels no greater than 13.5%. Table 15 shows the constraining ratio calculation; Table 16, Column E, shows the final FPT rate components; and Table 17 shows utility and resource level revenues from FPT customers. Appendix F shows the development of the FPT compensation factors for each resource wheeled under FPT.

2.5.3 <u>Firm Network Rate Calculations.</u> After the FPT rate is calculated and revenues are forecasted, the remaining firm Network rates are determined. *See* Table 12. First, the difference between the Network cost allocated to FPT and FPT revenues (the FPT revenue deficiency) is prorated between the Base Charge and the Transmission Load Shaping Charge. The Base Charge (which includes the IR and PTP rates, and the NT/NTP Base Charge) is directly allocated $227.5 million per year and receives an additional $10.2 million per year of the FPT revenue deficiency. The resulting $237.7 million is divided by an average annual billing determinant of 19,206 MW to produce the Base Charge of $1.000/kW/month. The PTP and RNF weekly and daily rates are calculated from the Base Charge in accordance with FERC methodology.

Table 12 also shows the calculation of the NT/NTP Transmission Load Shaping Charge. The Transmission Load Shaping Charge equals the allocated Network costs ($38.5 million per year) plus a share of the FPT underrecovery ($1.7 million per year) divided by the Transmission Load Shaping billing determinant (an average of 6218 MW per year).

2.5.4 Delivery Charge Calculation. The Transmission Settlement Agreement provides for a Utility Delivery Charge of $9.00/kW/year. This charge results in an underrecovery of $6.3 million per year. *See* Table 18. The 12 CP billing determinants used to compute the underrecovery are developed in Appendix C. Table 3 shows the Utility Delivery underrecovery assigned to the BPA power business. Appendix J demonstrates that half of the underrecovery is met by cost cuts, consistent with the Transmission Settlement Agreement. A comparison of the $6.3 million per year underrecovery to cost cuts since the supplemental rate proposal that benefit the BPA power business, demonstrates that these cuts are much larger than the underrecovery from the Utility Delivery Charge.

2.5.5 Intertie Rate Calculations

2.5.5.1 Southern Intertie Rate Calculation. Table 9 shows the development of the IS rate. Adjusted Southern Intertie costs from Table 3 are divided by all projected energy (firm, nonfirm, Federal, and non-Federal) over the Federal portion of the Southern Intertie to compute the hourly nonfirm IS rate. This number is rounded up by .01 mills to 2.54 mills/kWh to recover the IS revenue requirement. Total forecasted firm use on the Southern Intertie including nonfirm amounts estimated to fit within BPA GenCo’s firm IS demands determines the appropriate firm load factor on the Southern Intertie. This load factor (0.69) multiplied by the nonfirm IS rate cap times the hours in the year (8.76) yields the firm IS annual demand charge of $1.274/kW/month. These rates apply equally to Federal and non-Federal sales and uses of the Southern Intertie. The IS weekly and daily rates are calculated in accordance with FERC methodology.

2.5.5.2 Montana Intertie Rate Calculation. The Montana Intertie rate equals BPA's payment under the TGT rate for the Montana Intertie facilities divided by its capacity allocation of 185 MW. The IM weekly, daily, and hourly rates are calculated in accordance with FERC methodology. *See* Table 9.

2.5.5.3 Eastern Intertie Rate Calculation. The IE rate for nonfirm service is developed by dividing the Eastern Intertie segment cost (Table 1) by the forecast amount of Colstrip energy. (*See* Table 9.) The proposed IE-96 rate cap is 1.68 mills/kWh. The primary purpose of the IE rate is to credit the TGT rate.

3. TRANSMISSION RATE SCHEDULES

3.1 Formula Power Transmission Rates (FPT-96.1 and FPT-96.3)

The FPT-96.1 and FPT-96.3 rates are available for firm transmission for non-Federal power on the Network for both full-year and partial-year service. (Nonfirm wheeling may not be done at the FPT rate.) The embedded cost FPT rates include a distance component for transmission lines and various transformation and terminal charges. The FPT-96.1 rate is used for contracts allowing annual rate adjustments. The FPT-96.3 rate is used for contracts that allow a rate change only once every 3 years. Both FPT rates are adjusted in this rate proposal and have the same charges. FPT service does not allow assignment of Transmission Demand to third parties. The FPT rates apply only to existing contracts.

The FPT rate schedules also include the Reactive Power Charge, the Reservation Fee for Transmission Capacity, and notice regarding ancillary services. *See* section 3.11 for further discussion of these provisions.

3.2 Integration of Resources Rate (IR -96)

The proposed IR -96 rate is a "postage stamp" rate (independent of distance) with a demand charge in the embedded cost rate. The IR rate applies to existing agreements for the transmission of non-Federal power; such agreements are used to integrate multiple resources and transmit power to multiple points of delivery at the customer's system. Nonfirm wheeling, up to the contractually specified total Transmission Demands, may be done at the IR rate, subject to the availability of transmission capacity. Contractually specified IR Transmission Demands for Points of Integration are based on the annual peak output of a generating resource or annual peak demand in a purchase power agreement. The billing factor for the embedded cost IR demand charge is Total Transmission Demand. Upon agreement, the IR rate may be applied to other services, such as access to an intertie. IR service does not allow assignment of Transmission Demand to third parties.

BPA proposes to continue the Short Distance Discount (SDD) which decreases the IR rate by up to 40 percent when the distance between Point of Integration and Point of Delivery is less than 75 circuit miles. This is an exception to the postage-stamp demand charge for transactions that customers can demonstrate use only specific FCRTS facilities for a distance of less than 75 circuit miles. This demonstration is made as part of the process of negotiating an agreement that uses this rate schedule. The proposed SDD has been altered slightly in response to the elimination of the IR energy charge. The SDD is determined by the following formula:

$$.6 + \frac{.4 \ \text{x} \ \text{transmission distance}}{75 \ \text{miles}}$$

The IR rate schedule also includes an opportunity cost rate, the Delivery Charge, the Reactive Power Charge, the Reservation Fee for Transmission Capacity, notice regarding ancillary services, and notice of BPA's intent to charge incremental cost rates for new or increased IR service under specified conditions. *See* section 3.11 for further discussion of these provisions.

3.3 Network Integration Rate for 1981 Contracts (NTP-96)

The proposed NTP rate is available for delivery of Federal power under the 1981 Contracts and is applicable to utilities participating in the Residential Purchase and Sale Agreements. The NTP rate represents the unbundling of the transmission cost from the power cost for service to BPA's 1981 Contracts. The transmission costs allocated to the NTP rate have previously been bundled in the Priority Firm rate charges.

The charges for service over the Network facilities include the Base Charge, Transmission Load Shaping Charge, and the Reserved Capacity Charge. The Base Charge is applied to the amount of the customer's PF purchase on the hour of the Monthly Transmission Peak Load for Metered Requirements Customers (MRC), and to the highest hourly HLH PF purchase for Computed Requirements Customers (CRC). The Transmission Load Shaping Charge is applied to the highest hourly PF purchase for MRCs, and to the customer's monthly Computed Maximum Requirement for CRCs. Only the CRCs are subject to the Reserved Capacity Charge which is assessed on the difference between their Transmission Load Shaping Charge and Base Charge billing factors. The Reserved Capacity Charge is set at 1/12 of the monthly Base Charge so that BPA receives some compensation for the firm transmission capacity reserved for CRCs but not used.

The CRCs have an option to waive all or a portion of their CMR. If they waive, then the Base Charge is applied to their adjusted CMR and the Transmission Load Shaping Charge is applied to their CMR less the smallest declared waived amount for the year. The Reserved Capacity Charge is not assessed if the customer waives CMR.

Transmission service for DSIs under 1981 Contracts is charged the Base Charge applied to their Operating Level. RPSA utilities are charged the Base Charge and Transmission Load Shaping Charge applied to the demand associated with the utility's residential load.

The NTP Unauthorized Increase Charge is applied to CRCs who exceed their CMR. The NTP rate schedule includes the Reactive Power Charge and the Delivery Charge. *See* section 3.11 for further discussion of these charges.

3.4 Network Integration Rate (NT -96)

The proposed NT -96 rate applies to Transmission Customers taking transmission service under the Network Integration Service Tariff and to certain Full Requirements Customers under 1996 Contracts. The NT Tariff provides transmission service for a customer's retail load. The NT rate schedule includes rates for Network use and rates for Delivery use. Charges for use of the Network include a Base Charge and a Transmission Load Shaping Charge. The NT Base Charge is billed on a net load basis: it is applied each month to the customer's total load that occurs on the hour of the Monthly Transmission Peak Load (MTPL) less Declared Customer-Served Load (Declared CSL). Declared CSL is the monthly amount of capacity load the customer declares it will serve on a firm basis without using NT transmission service. The Actual CSL, the amount of the customer's load that is actually served without using NT service, must be greater than 60 percent of the Declared CSL on average over all the Heavy Load Hours (HLH). If the customer fails to maintain its Actual CSL at this level, it will be billed for its total retail load on the hour of the MTPL. In addition, if the Actual CSL is less than the Declared CSL on the hour of the MTPL, the NT Unauthorized Increase Charge is applied to the difference between the Actual and Declared CSL.

The Transmission Load Shaping Charge is applied to the customer's Network Load on the hour of the MTPL. This Charge recovers the cost of having transmission available to serve the customer's annual peak load as well as the cost of transmission losses.

The NT rate schedule also includes the Redispatch Credit which provides for a credit to an NT customer whose resource is redispatched pursuant to the NT tariff. In addition, the NT rate schedule includes the Reactive Power Charge, the Delivery Charge, notice regarding ancillary services, notice of BPA's intent to charge incremental cost rates under specified conditions, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. Finally, the rate schedule provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.5 Point-to-Point Rates for Network Service

BPA proposed to provide PTP service on the Network under three rate schedules: the PTP rate for firm service; the Reserved Nonfirm (RNF) rate for short-term nonfirm service; and the Energy Transmission (ET) rate for hourly nonfirm service.

3.5.1 Point-to-Point Rate (PTP-96). The proposed PTP-96 rate applies to firm Network transmission service on a contract path basis. PTP service may be used to serve native load and transactions with third parties over Network (with access to the Interties) and Delivery facilities. NT customers must use PTP service for sales to third parties. The PTP rate schedule also applies to DSIs that execute a 1996 Contract but have not executed a PTP Service Agreement. The PTP rate schedule includes monthly, weekly, and daily rates for Network use and rates for Delivery use.

The embedded cost PTP Network demand charge is applied to the sum of Transmission Demands at POIs or PODs, whichever is greater. Only Transmission Demands for generating units that are not located within BPA's Control Area and for generating units that are located within BPA's Control Area but are not subject to redispatch by BPA are used to calculate the PTP billing factor. The proposed billing factors for DSIs that have not executed a PTP Service Agreement are tailored to provisions of their 1996 Contract and apply to the highest demand requested. The Short-Distance Discount in the PTP rate schedule is very similar to the SDD in the IR rate.

The PTP rate schedule includes the Redispatch Credit which provides for a credit to a PTP customer whose resource is redispatched pursuant to the PTP tariff. The PTP rate schedule also includes the Delivery Charge, an opportunity cost rate, the Reactive Power Charge, notice regarding ancillary services, the Reservation Charge for Transmission Capacity, notice of BPA's intent to charge incremental cost rates under specified conditions, an Unauthorized Transmission Increase charge, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. Finally, the rate schedule provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.5.2 <u>Reserved Nonfirm Transmission Rate (RNF-96).</u> The proposed RNF rate schedule is available for Short-Term Nonfirm service of Federal and non-Federal power over Network facilities. Short-Term Nonfirm service is reserved and/or scheduled daily, weekly, or monthly for renewable terms of not more than 30 days each. The rate schedule is similar to the PTP rate schedule: the charges are the same as those in the PTP rate schedule except that, under the RNF rate schedule, they are caps and are downwardly flexible. If service is interrupted, the Transmission Customer is credited by prorating the hours of interruption over the total hours in the period.

The RNF rate schedule also includes an Unauthorized Transmission Increase charge, the Reactive Power Charge, notice regarding ancillary services, and the Rate Adjustment Due to FERC Order Under FPA §212. <u>*See*</u> section 3.11 for further discussion of these provisions.

3.5.3 Energy Transmission Rate (ET-96). The proposed ET rate schedule is available for Hourly Nonfirm service of Federal and non-Federal power. This energy rate is a cap and is downwardly flexible.

The ET rate schedule includes notice regarding ancillary services, the Reactive Power Charge, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions.

3.6 Point-to-Point Rates for Intertie Service: Southern Intertie Rate (IS-96) and Montana Intertie Rate (IM-96)

The IS and IM rate schedules are applicable to all transmission service on the Southern Intertie and Montana Intertie, respectively, under the terms and conditions of the PTP tariff. In addition, the IS rate schedule applies to transmission contracts for Southern Intertie service in effect prior to October 1, 1996. The IS and IM rate schedules include rates for firm, short-term nonfirm, and hourly nonfirm service. The short-term nonfirm and hourly nonfirm rates are caps that are downwardly flexible. The IS rates are applicable to north-to-south and south-to-north transactions. The IM rate is new and provides for service over BPA's 185 MW of east-to-west capacity rights. BPA is not proposing a Northern Intertie rate in accordance with the Transmission Settlement Agreement.

The IS and IM rate schedules include an opportunity cost rate for firm service, the Reactive Power Charge, an Unauthorized Transmission Increase charge, the Reservation Fee for Transmission Capacity, notice regarding ancillary services, notice of BPA's intent to charge incremental cost rates under specified conditions, notice of BPA's intent to charge incremental cost rates under specified conditions, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. In addition, the rate schedules provide for a credit for interruption of short-term nonfirm service. Finally, the rate schedules provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.7. Townsend -Garrison Transmiss ion Rate (TGT -96) and Eastern Intertie Rate (IE -96)

The proposed TGT and IE rates are proposed based on provisions of the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended). The TGT -96 rate recovers the cost of the Towsend-Garrison facilities. The IE -96 rate is available to parties to the Montana Intertie Agreement for nonfirm transmission service on the Eastern Intertie on the portion of the Eastern Intertie capacity above BPA's firm transmission rights. The stated rate, an energy charge, sets the cap and is downwardly flexible. Revenues from these transactions are treated as a revenue credit against the TGT rate. IE rate revenues are used also to credit TGT -96 to the extent other TGT participants anticipate nonfirm transmission revenues.

3.8 Market Transmission Rate (MT -96)

The MT -96 rate is available for Western Systems Power Pool (WSPP) transactions using FCRTS facilities for wheeling services under the WSPP Agreement. This rate conforms to the pricing requirements of the FERC order approving the WSPP on a permanent basis (*See* 55 F.E.R.C. ¶61,099 (1991), and 55 F.E.R.C¶61,495 (1991)), and specifies pool -wide cost -based transmission rate levels for hourly, daily, weekly, and monthly transactions. The rate schedule remains the same with the exception of the addition of the Reactive Power Charge and Ancillary Service provision. *See* section 3.10 for further description of these provisions.

3.9 Use-of-Facilities Transmission Rate (UFT -96)

Wheeling transactions over specifically identified facilities occur under the UFT -96 formula-based rate. The UFT rate schedule now provides explicitly for UFT charges on a sole-use basis, a common practice for establishing UFT charges when only one customer uses specified facilities. In addition, the Reactive Power Charge and notice regarding ancillary services has been added to the rate schedule.

3.10 Advance Funding Rate (AF -96)

This new rate schedule allows BPA to collect the capital and related costs of specified BPA -owned transmission facilities through advance funding when such advance payment is provided for in an agreement with a customer. Such facilities could include interconnection and resource integration facilities, and upgrades, reinforcements, and replacements to the FCRTS. Following commercial operation of the specified facilities, a true -up of estimated costs with actual costs would occur. Application of this rate shall be pursuant to FERC transmission pricing policy.

3.11 Other Charges and Provisions

3.11.1 Delivery Charges. The Delivery Charge is in the IR, NT, NTP and PTP rate schedules and recovers the cost of the facililities in the DSI Delivery and Utility Delivery segments. The Delivery Charge is applied to both Federal and non-Federal power using Delivery facilities. DSIs are charged for DSI Delivery facilities through UFT charges. The rate for Utility Delivery is fixed at $0.75/kW/month in accordance with the Transmission Settlement Agreement.

The Delivery Charge is described in section II.F.in the General Rate Schedule Provsions (GRSPs) and will apply to all power flowing over Delivery facilities with the exception of those Delivery facilities being charged a UFT rate under existing contracts. For most customers, the Delivery Charge will be assessed to the demand on the Delivery facilities on the hour of the Monthly Transmission Peak Load. However, the billing factor for CRCs for the Delivery Charge shall be the customer' s peak purchase from BPA during HLHs in accordance with the Transmission Settlement Agreement. Therefore, the hour of the CRCs peak purchase from BPA will be used to determine the Delivery Charge billing factor for CRCs for both power purchases and wheeling.

When a CRC purchases no power under its 1981 Contract during HLH, but is using a Delivery facility for wheeling, the billing factor will be all power using the Delivery facilities on the hour of the Monthly Transmission Peak Load. For new IR demand, the uniform Delivery Charge will be applied for use of specific Delivery facilities not covered in a UFT charge. The Delivery Charge will be based on the total amount of power flowing over the facilities less the amount of transmission service used in calculating the UFT charge in order to avoid double-charging for the Delivery facilities.

3.11.2 Reactive Power Charge . BPA is proposing to charge customers for their reactive power requirements. The Reactive Power Charge will replace the Power Factor Adjustment provisions in BPA' s current power rates and will also apply to wheeling customers. BPA will bill the customer directly for measured quantities of reactive demand and reactive energy which fall outside a specified deadband. The deadband for the first three years of the rate period will be equal to 33% of the highest real power demand (equivalent to 95% power factor) at the POI/POD during the billing month. The deadband will be reduced to 25% of the highest real power demand (equivalent to 97% power factor) at the POI/POD during the billing month for the last two years of the rate period. Half of the installed costs attributable to reactive power are assigned to the reactive demand, and the other half to reactive energy. The Reactive Power Charge will only apply to lagging reactive demand and energy during Heavy Load Hours and only to leading reactive demand and energy during Light Load Hours. The demand charge for lagging reactive power is based on the installed cost of capacitors; the demand charge for leading reactive power is based on the installed cost of reactors.

A two-year, eleven-month ratchet will be applied to the demand charge. There will be separate ratchets for leading and lagging reactive demand. Customers can reset the ratchet at a POI or POD to zero if they maintain their reactive demand at the point to 25% or less of the real power demand for a continuous 12-month period. BPA calculated the reactive energy charge based on an estimate of the annual reactive energy flowing on the transmission system. The same energy charge applies to both lagging and leading reactive energy. Calculation of the Reactive Power Charge is shown in Appendix H.

The Reactive Power Charge, section II.O. in the General Rate Schedule Provisions and included in BPA's power and transmission rate schedules, is applied hourly to each POI and POD between BPA and the customer where the flow of real power (MW) is from BPA to the customer. A customer taking power under multiple rate schedules will pay for its reactive power requirements at each point as if it were taking service under only one rate schedule.

3.11.3 Reservation Fee for Transmission Capacity. The Reservation Fee for Transmission Capacity, section II.P. in the General Rate Schedule Provisions, is included in most of the firm transmission rate schedules (FPT, IR, PTP, IS, and IM) for application to customers who enter into a contract with BPA for new or increased firm transmission service on the FCRTS and want to postpone service for up to 5 years. The Reservation Fee is modeled on provisions in the PTP tariff. Payment of one-twelfth of the annual revenues allows a customer with an executed contract for transmission service to reserve transmission capacity for 1 year, or portion thereof. If BPA receives a request for service over the same transmission path and there is insufficient capacity to accommodate both, the original transmission customer may begin paying the full monthly transmission rate or release the reserved capacity.

3.11.4 Opportunity Cost Rates. A charge is included in the firm transmission rates (IR, PTP, IS, and IM rates) to allow BPA to charge an opportunity cost rate for requests for firm transmission service over constrained Federal transmission capacity. Transmission service over unconstrained capacity would not be subject to the opportunity cost rate. BPA will apply the opportunity cost rate consistent with FERC's "or" pricing: the higher of embedded cost or opportunity cost would be charged, but not the sum of the two.

3.10.4 Incremental Cost Rates. BPA provides notice in most of the firm rate schedules that requests for new or increased firm transmission service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates. Such rates would be developed pursuant to section 7(i) of the Northwest Power Act. Similar to the opportunity cost rate option discussed above, transmission service over available capacity would not be subject to an incremental cost rate. BPA will apply the incremental cost rate consistent with FERC's "or" pricing: the higher of embedded cost or incremental cost would be charged, but not the sum of the two.

3.11.5 Unauthorized Transmission Increase Charge

For rate schedules under the PTP tariff (PTP, RNF, IS, and IM), BPA is proposing to include a Unauthorized Transmission Increase Charge. The charge for exceeding transmission demands is set at the annual PTP rate of $12.00 per kW per month. The Unauthorized Transmission Increase charge would not be applied if the transmission customer arranges for nonfirm transmission prior to exceeding contracted amounts.

3.11.6 Ancillary Services

See discussion of Unbundled Products in the WPRDS (WP-96-FS-BPA-05).

3.11.7 Rate Adjustment Due to FERC Order Under FPA §212. This provision is included in the NT, PTP, RNF, ET, IS, and IM rate schedules which are designed to offer service comparable to BPA's use of the system. These rate schedules, after review by FERC, may be modified to satisfy statutory standards for FERC-ordered transmission service. For customers taking non-FERC-ordered transmission service, the modifications shall be effective only prospectively from the date of the final FERC order that grants final approval of the rate schedule for FERC-ordered transmission.