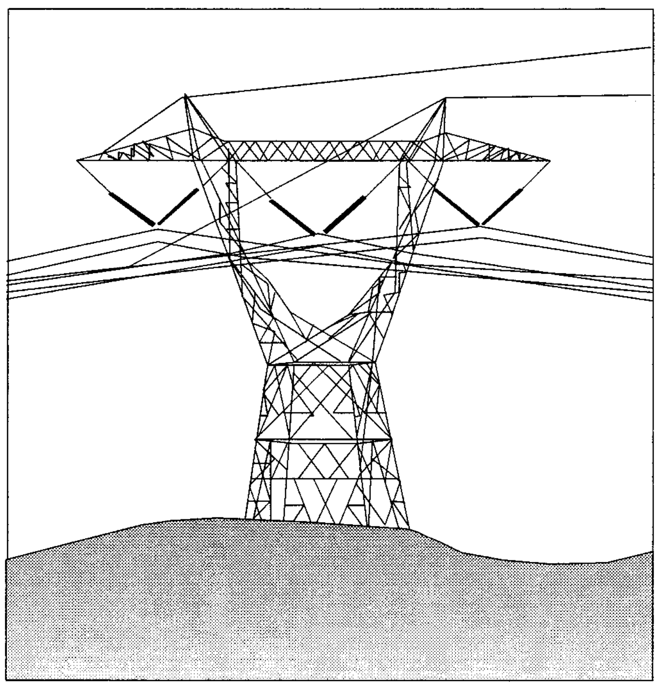
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

2002 FINAL TRANSMISSION PROPOSAL

TRANSMISSION RATE STUDY

TR-02-FS-BPA-03



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AUGUST 2000

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COMMONLY USED ACRONYMS

AC	Alternating Current
ACS	Ancillary Services and Control Area Services (Rate)
AF	Advance Funding (Rate)
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
ASC	Average System Cost
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
Btu	British Thermal Unit
CA	Control Area
CAISO	California Independent System Operator
California PX	California Power Exchange
CAS	Control Area Service
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
CPTC	Columbia Power Trades Council
CRAC	Cost Recovery Adjustment Clause
CSL	Customer-Served Load
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DOE	Department of Energy
DOI	Department of Interior
DSIs	Direct Service Industrial Customers
EIA	Energy Information Administration
Energy Northwest	Formerly Washington Public Power Supply System Project
F&O	Financial and Operating Reports
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FPT	Formula Power Transmission Rate
FTE	Full-time Equivalent
FY	Fiscal Year (Oct-Sep)
GDP	Gross Domestic Product
GI	Generation Integration
GRSPs	General Rate Schedule Provisions
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hours
HNF	Hourly Non-Firm

IDC	Interest During Construction
IE	Eastern Intertie (Rate)
IM	Montana Intertie (Rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (Rate)
IR	Integration of Resources (Rate)
IS	Southern Intertie (Rate)
ISC	Investment Service Coverage
ISO	Independent System Operator
kcfs	kilo (thousands) of cubic feet per second
kV	Kilovolt (1000 volts)
kVAr	Kilovoltampere Reactive
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LLH	Light Load Hours
m/kWh	Mills per kilowatthour
MAF	Million Acre Feet
MORC	Minimum Operating Reliability Criteria
MTPL	Monthly Transmission Peak Load
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Network Contract Demand (Service and Rate)
NERC	North American Electric Reliability Council
NF	Nonfirm Energy
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NT	Network Integration Transmission (Service and Rate)
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMB	Office of Management and Budget
OY	Operating Year (Aug-Jul)
PA	Public Agency
PBL	Power Business Line
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration (or, Interconnection)

POR	Point of Receipt
PSW	Pacific Southwest
PTP	Point to Point (Service and Rate)
PUD	Public or People's Utility District
Reclamation	Bureau of Reclamation
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase Sale Agreement
RRS	Revenue Requirement Study
RTO	Regional Transmission Organization
SCADA	Supervisory Control And Data Acquisition System
Tariff	Open Access Transmission Tariff
BPA-TBL	Transmission Business Line
TCH	Transmission Contract Holder
TGT	Townsend-Garrison Transmission (Rate)
TPP	Treasury Payment Probability
TRAP	Transmission Risk Analysis Processor
TRS	Transmission Rate Study
TTSL	Total Transmission System Loading
UIC	Unauthorized Increase Charge
UFT	Use of Facilities (Rate)
USBOR	U.S. Bureau of Reclamation
VOR	Value of Reserves
WEFA	Wharton Econometric Forecasting Associates
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
1CP	One Coincidental Peak
12CP	Twelve Coincidental Peak

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1. INTRODUCTION

1.1 Purpose

The Transmission Rate Study (TRS) presents an overview of the Bonneville Power Administration Transmission Business Line (BPA-TBL) rate design process for developing the proposed transmission and ancillary service rates. The rates calculated in the TRS are published in the Transmission and Ancillary Service Rate Schedules and General Rate Schedule Provisions. 2002 Final Transmission Record of Decision, TR-02-A-01, Appendix B. A summary of the proposed rates is shown in Table 10.

BPA-TBL proposes transmission rates for a two-year rate period—Fiscal Years (FYs) 2002 and 2003. (A fiscal year runs from October 1 through September 30.) The overall level and design of transmission and ancillary service rates is governed by BPA's statutory obligations, commitment to comparability, contractual arrangements, the resolution of interbusiness line issues, and the consideration of other factors such as revenue stability, rate continuity, and ease of administration. In addition, the final transmission rate proposal is guided by the Transmission Rates and Transmission Terms and Conditions Settlement Agreement (Settlement Agreement), negotiated by BPA-TBL and the rate case parties, which specifies various rate levels and other rate provisions. The TRS first briefly discusses some of these factors and then discusses the methodology used to develop the rates.

1.2 Overview of the Basis for Rate Development

Factors influencing the level and design of transmission rates are statutory obligations, comparability, interbusiness line issues resolved in the 2002 Power Rate Case, the Settlement Agreement, and contractual arrangements.

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 <u>Comparability</u>

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 has 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 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 to its transmission facilities with 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). <u>*See*</u> <u>also</u> 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 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 possible through sections 211 and 212 of the Federal Power Act, to promote a national policy of open transmission access. *Id.* at 21,573. BPA has determined it will comply with Order 888 to the extent it is compatible with existing legislative authority.

As part of the Settlement Agreement, parties negotiated a proposed BPA-TBL Open Access Transmission Tariff (OATT) modeled on the FERC *pro forma* tariff. The proposed OATT includes terms and conditions of general applicability for open access transmission service, including Network Integration service and Point-to-Point service. In conjunction with the proposed open access transmission services, BPA-TBL proposes the Network Integration (NT) rate, Point-to-Point (PTP) rate, Southern Intertie

(IS) rate, Montana Intertie (IM) rate, and the Ancillary Services and Control Area Services (ACS) rate. In addition, the Integration of Resources (IR) rate and the Formula Power Transmission (FPT) rates are proposed for pre-OATT firm wheeling contracts.

1.2.3 <u>Interbusiness Line Issues</u>

Certain issues that affect the transmission and ancillary service rates have been decided in the 2002 Power Rate Case. These issues are: a methodology for functionalizing costs between generation and transmission, including a methodology for functionalizing corporate overhead costs to the business lines; unit costs for generation inputs for operating reserves and regulation ancillary services; the generation input cost for reactive supply and voltage control from generation sources; the generation costs of station service and remedial action schemes; and the allocation of generation integration and generator step-up transformer costs to the business lines. Also decided in the Power Rate Case is a treatment for costs of delivery of non-Federal power over third-party transmission systems, and the BPA Power Business Line's (BPA-PBL) financial support of the Delivery Charge. In calculating the proposed transmission and ancillary services rates, BPA-TBL has reflected the Administrator's decisions in the 2002 Final Power Rates Record of Decision, WP-02-A-02.

1.2.4 <u>Settlement Agreement</u>

BPA-TBL and the parties to the 2002 transmission rate proceeding entered into settlement discussions shortly after BPA-TBL's initial rates and terms and conditions proposals were published and the formal proceedings commenced. BPA-TBL and the parties were concerned about the need to staff the BPA-TBL rate case, the terms and conditions proceeding, and efforts to form a regional transmission organization (RTO), all of which were all on a similar schedule. The formation of the RTO is driven by the deadlines in the Federal Energy Regulatory Commission's Order 2000. In addition, certain parties wanted to know what transmission services BPA-TBL would offer, and their associated transmission rates, prior to signing power sales contracts with the BPA-PBL in Fall 2000.

On April 20, 2000, the BPA-TBL and the parties settled the transmission and ancillary service rate levels, contingent upon settling the transmission terms and conditions of the BPA-TBL OATT by June 20, 2000. BPA-TBL and the parties settled the terms and conditions of BPA-TBL's OATT and some additional rate issues on June 20, 2000. The April 20 and June 20, 2000, settlement agreements, together with the proposed OATT, comprise the TR-02/TC-02 Settlement Agreement. 2002 Final Transmission Record of Decision, TR-02-A-01, Appendix A.

In addition to specifying the proposed rate levels for the transmission services offered by BPA-TBL, a number of Settlement Agreement provisions affect BPA-TBL's rate schedule provisions. The Settlement Agreement provisions associated with the OATT also cause some rate changes; e.g., the Network Contract Demand (NCD) service proposed by BPA-TBL in the 2002 Terms and Conditions Initial Proposal, TC-02-E-BPA-01, was eliminated, and therefore, necessitates elimination of the associated NCD rate.

1.2.5 <u>Contractual Arrangements</u>

BPA-TBL and its 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. For example, some agreements 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. BPA-TBL will honor these agreements when setting and applying the new transmission rates.

2. RATE METHODOLOGY

2.1 Rate Construct

The transmission and ancillary service rates are set at levels specified in the Settlement Agreement. The Settlement Agreement provides i) rate levels which are the combination of the transmission rate (PTP, NT, IS) and the two required Ancillary Service rates (Scheduling, System Control, and Dispatch (Scheduling) Service and Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service); ii) specific rate levels (FPT, IR, Utility Delivery Charge); and iii) other information regarding ratesetting (DSI Delivery Charge, Unauthorized Increase Charge, short-term firm and non-firm rates). Rates that were not specified in the Settlement Agreement were to be set at levels not to exceed the rate levels in the 2002 Initial Transmission Rate Proposal (IM, IE, remaining Ancillary Service rates).

The relationship among the rates that exists for the current 1996 rates is continued with the proposed 2002 rates. The combination of the transmission rates (PTP, IR, and NT Base Charge) plus the two required Ancillary Service rates are set equal to each other. Again, as in 1996, the 2002 FPT rate is not included in this construct because of its different rate design. However, the increase in the FPT and IR rates (both of which include the two required Ancillary Services) is the same as the PTP increase, including the two required Ancillary Services.

Similar to the rate development for the current 1996 transmission rates, transmission service for BPA-PBL is accounted for in the same manner as for all other transmission customers. To calculate rates and forecast revenues under proposed rates, BPA-TBL forecasts Network and Intertie transmission sales to each transmission customer under each service. The BPA-PBL uses the transmission system under Open Access service agreements and such use is forecasted in the same manner as for all other transmission customers. Firm PTP contract demands are assigned to BPA-PBL's grandfathered sales and exchanges, consistent with current treatment of these bundled contracts.

2.2 Cost

The Revenue Requirement Study (TR-02-FS-BPA-01) determines the test period revenue requirement for transmission and ancillary services. From that, the revenue requirement for each segment is determined. The Segmentation Study (TR-02-FS-BPA-02) identifies the transmission facilities and associated investment and O&M cost for each transmission segment and, thus, provides a basis for segmenting the revenue requirement.

2.2.1 Segmentation Study

BPA-TBL operates and maintains the FCRTS to provide 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 for the transmission segments. The Study also provides the historical investment base and test year O&M associated with ancillary services. This provides the basis for segmenting the revenue requirements used to develop rates. Corps of Engineers (COE) and Bureau of Reclamation (USBR) transmission facilities are not included in the Segmentation Study. Instead, COE and USBR Network and Delivery transmission costs are included in the BPA-PBL revenue requirements and charged to the BPA-TBL through interbusiness line transfers. Final Power Rates Record of Decision, WP-02-A-02, at 5-69 – 5-70. *See* Revenue Requirement Study, TR-02-FS-BPA-01.

In the Segmentation Study, the FCRTS is divided into six transmission 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. The Utility Delivery and DSI Delivery segments include facilities with voltages below 34.5 kV. In addition, an ancillary services segment, further divided into six sub-segments, is developed.

2.2.2 Revenue Requirement Study

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. The Revenue Requirement Study for transmission is prepared consistent with BPA's statutory obligation to set rates to recover, in accordance with sound business principles, all costs of transmitting electric power, including the repayment of the Federal investment in the FCRTS over a reasonable number of years, and all other FCRTS costs.

The process used to develop each revenue requirement consists of three parts. First, repayment studies are prepared for the transmission function to determine the projected annual interest expense and amortization of 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 FCRTS are compiled. Third, planned net revenues determined by the Administrator's financial objectives are calculated, if necessary, and added to the operating and net interest expense. *See* Revenue Requirement Study, TR-2-FS-BPA-01.

Thus, transmission revenue requirements are set at levels sufficient to meet the annual operating expenses of the FCRTS, to cover interest expense, and to recover planned net revenues that ensure BPA's ability to make annual amortization payments on the Federal investment as determined by the transmission repayment studies. The segmented transmission revenue requirements for FYs 2002 and 2003 are shown in Table 1.

2.2.2.1 <u>General Transfer Agreement (GTA) Cost</u>

The revenue requirement includes a cost item for "General Transfer Agreements for nonfederal power." *See* Table 1, lines 1.11 and 1.28. BPA-TBL shall pay up to $6.5 million annually to acquire Network-equivalent transmission for the non-Federal power purchases of GTA customers and shall roll this cost into the Network. 2002 Final Power Rates Record of Decision, WP-02-A-02, Chapter 9. BPA-TBL forecasts this cost to be $2.0 million per year.

2.2.3 Revenue Credits and Cost Adjustments

The segmented transmission revenue requirement is adjusted for revenue credits to arrive at the segment cost used to set the two required Ancillary Service rates and to determine the cost to be recovered from the BPA-PBL for Generation-Integration cost. The adjusted segmented revenue requirements are referred to in the TRS tables as "rate development costs." Expected revenues from various sources are identified and segmented in Table 2. These revenue credits are revenues from sources other than the general transmission rates developed in the TRS.

The segmented revenue credits are subtracted from the appropriate segment revenue requirement. *See* Table 3. Two additional adjustments are made to the revenue requirement to determine the rate development costs. The net cost of the Eastern Intertie is allocated and the stability reserves credit is calculated and allocated. The net cost of the Eastern Intertie equals 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 calculation of the stability reserves credit of $0.543 million per year. The DSI IR and PTP contracts provide for a credit to be given to DSIs for BPA-TBL's right to instantaneously disconnect DSI loads from the electrical power system using a high-speed load-tripping scheme known as the Import Contingency Load Tripping Scheme. This system protects against Southern Intertie outages when the Intertie is used to import power into the PNW. The credit is a formula rate based on the change in the Industrial Firm Power (IP) rate. The stability reserves reservation fee currently in effect is applied to forecasted DSI transmission demand for smelter loads. The cost of providing the stability reserves credit is segmented to the Southern Intertie. In addition, the difference between the DSI Delivery Segment net cost and the DSI Delivery Charge revenue is allocated to the Network.

Finally, the Generation Integration segment is comprised of transmission facilities that integrate Federal resources to the Network. The net cost of the Generation Integration segment, $7.302 million per year (Table 3, column A, line 3.17), is assigned wholly to the BPA-PBL and recovered through power rate charges. 2002 Final Power Rates Record of Decision, WP-02-A-02, at 5-69 - 5-70.

2.3 Loads

Transmission loads on the Network and Southern Intertie are forecast using contract demands in long-term contracts, point of delivery load forecasts for NT service, and FY 2000 short-term sales. The forecasts are shown on Tables 4 and 5. For the forecast of Network and Southern Intertie loads, current contract demands that are effective through the FY 2002 and 2003 rate period are determined first. Then, for the Network, BPA-TBL forecasted which Network service(s) it expects will be used by the remaining customers.

Customers have a number of choices with regard to Network transmission service and have options to switch their current service to an OATT service. BPA-TBL has four long-term firm services on the Network. The proposed OATT provides a window to allow customers to convert their current service to an OATT service (PTP, NT). In addition to the conversion option, customers who are currently taking transmission service under their 1981 power sales contracts, or whose existing PTP, IR, FPT, or NT agreements are expiring before or during the 2002 rate period must select an OATT service.

2.3.1 <u>Sales from Long-Term Contracts</u>

Long-term Network and Southern Intertie transmission demands are shown in Table 4. The demands for FPT, IR and PTP on the Network and Southern Intertie reflect current contracts that are effective during the forecast period. Several PTP contracts that expire prior to FY 2002 were assumed to extend through the rate period. *See* Appendix A. PTP service on the Network and Southern Intertie is shown separately for BPA-PBL grandfathered contracts and for all other PTP service agreements.

For the customers that are not covered by a current long-term contract, loads and revenues are forecasted for both NT and PTP service in order to determine which service the customer would likely take. *See* section 2.3.1.1, Network Rate Choice. Non-generating public utility load forecasts are based on an analysis of recent history. Appendix D describes the non-generating public utility load forecast methodology and provides a list of the utilities that this method was used for. The forecasted non-generating utility monthly loads coincident with BPA-TBL's monthly system peak are the NT Load Shaping Charge billing determinants. These same monthly loads, adjusted for Customer Served Load (CSL), are the NT Base Charge billing determinants. Load served under IR, FPT, and PTP contracts is considered to be CSL. PTP demands are forecast to be each utility's highest forecasted monthly demand after adjustment for load served under IR, FPT, and PTP contracts. The IR, FPT, and PTP contract demands subtracted from the non-generating public utility's system load to forecast PTP and NT Base Charge billing determinants are taken from Appendix A.

The generating public utility forecast is based on load information contained in the Northwest Power Pool's Operating Program, December 1998, or the Pacific Northwest Loads and Resources Study (White Book), December 1998, and 17 months of actual sales (October 1998 through February 2000). The forecasted billing determinants for generating public utilities under the NT Base Charge and PTP rate exclude service to the customer's load that is served by internal generation or under IR, FPT, or PTP contracts. Appendix D, Table 2, contains generating public utility forecasted system loads and other information used to forecast billing determinants under both NT and PTP services, and to estimate internal generation. The contract demands subtracted from the generating public utility's system load to forecast PTP and NT Base Charge billing determinants are taken from Appendix A.

2.3.1.1 Network Rate Choice

The selection of Network transmission service for most customers is forecast from an analysis that determines the customer's least costly service. In general, the PTP contract demand service is less expensive for utilities with high load factors and little diversity from the total transmission system peak. NT service costs less than PTP contract demand service for low load factor customers with system peaks that differ from the overall transmission system peak. The forecast of customers' Network service is shown in Appendix E, Column B.

Seventeen transmission customers are assigned a Network service without regard to the results of the "choice analysis." Their assignment is based on information from the customer directly or from the customer's transmission account executive. Fifteen of the 17 utilities are modeled under NT service, and two utilities are modeled under PTP service in contrast to the choice analysis result. Additionally, all PNGC utilities are assumed to take NT service.

2.3.2 <u>Short-Term and Hourly Sales</u>

The forecast of short-term sales is shown in Table 5. Daily and hourly sales on the Network and Southern Intertie are forecast using a previous forecast for FY 2000 as the basis of the 2002/2003 rate period forecast. Short-term sales are adjusted for changes in long-term demands from FY 1999. Sensitivity coefficients of –0.700 and –0.442 between long-term and short-term sales are assumed for the Network and Southern Intertie, respectively. This forecasting model is calibrated to actual short-term revenues earned during the first seven months of FY 2000. Schematically, this forecast approach is represented as:

New Forecast = Old Forecast + (Demand Delta * Coefficient) + Calibration Term

The monthly, weekly, and daily sales produced by the forecasting model are converted to the Block 1 (first 5 days of a reservation) and Block 2 (day 6 and beyond of a reservation) sales to reflect the new rate structure. This conversion relies on the frequency and duration of reservations in FY 1998 and FY 1999.

The inverse relationships between short-term and long-term sales (the sensitivity coefficients) account for the trade-off between these markets. Increases in long-term sales should result in decreased short-term sales. Long-term sales on the Southern Intertie have increased substantially in recent years. For the rate review period, long-term sales on the Southern Intertie are 2.5 times what they were forecast in the 1996 rate case. The 44 percent Southern Intertie relationship reflects the estimated sensitivity of BPA-PBL's Southern Intertie short-term transmission purchases to changes in their long-term transmission purchases during FY 1998. Appendix D, Table D3 shows the summary statistics supporting this estimated relationship. The 70 percent coefficient for Network sales is an assumed relationship.

2.3.3 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 over Utility Delivery facilities at voltages below 34.5 kV. Appendix C shows the utilities and points of delivery forecasted to be subject to the Utility Delivery Charge. In addition to the substations already sold, the forecast assumes that customers will purchase additional substations during the remainder of the current rate period. All but two of the utilities appearing in Appendix C are non-generating publics. *See* Appendix D for forecast information for the non-generating publics. Utility delivery points for Clark Public Utilities and Grant County PUD are estimated from recent billing information.

2.4 Rate Calculations

To implement the Settlement Agreement, the two required Ancillary Service rates (Scheduling Service and Generation Reactive Service) are calculated. When these two rates are calculated, the PTP, NT, and IS rates, and the Unauthorized Increase Charge can be determined. Of the remaining rates, the FPT and IR rates are calculated by increasing the current 1996 rates by 24.3%. The Settlement Agreement specifies the level of the Utility Delivery Charge and the methodology for the DSI Delivery Charge. Finally, the IM and IE rates, and the remaining Ancillary Service rates are set at the levels proposed in the Initial Proposal, consistent with provisions in the Settlement Agreement.

The Montana Intertie (IM) rate is based on BPA-TBL's annual cost under the TGT rate, and the capacity of BPA-TBL's share of the facility. The IS and IM daily and hourly rates are calculated using the same methodology as that used for the PTP rate.

2.4.1 Ancillary Service Rates

The two required Ancillary Services rates, Scheduling, System Control, and Dispatch (Scheduling) Service and Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service, are calculated in this Study. The Regulation and

Frequency Response Service rate, and Spinning and Supplemental Operating Reserve Services rates are set at the levels calculated in the Initial Proposal. TR-02-E-BPA-03, at 66.

Rates are not calculated for the Energy Imbalance/Generation Imbalance Services. Under these Imbalance services, energy return is required if customers stay within an imbalance band; otherwise, customers pay a penalty rate. Control Area Service rates for Regulation and Frequency Response Service, and Spinning and Supplemental Operating Reserve Services are the same as the Ancillary Service rates. CAS rates allow a party to satisfy all of its reliability obligations for resources or loads in the BPA Control Area.

2.4.1.1 <u>Cost</u>

The two required Ancillary Service rates are based on the adjusted revenue requirement for Ancillary Services in Table 3. The revenue credit to the Ancillary Services revenue requirement is segmented among the Ancillary Services. Table 7, columns B and C. For customers taking FPT service, the two required services of Scheduling and Generation Reactive have not been unbundled. Therefore, the revenue requirements for these two required services are further adjusted to account for the portion of the revenue requirement being recovered through the FPT rates. Table 7, column D. The portion of FPT revenues associated with Ancillary Services is determined in Table 6 by prorating the revenues based on the relative proportions of Network rate development cost and Network-related Ancillary Service costs.

2.4.1.2 <u>Scheduling and Generation Reactive Rates</u>

Scheduling Service and Generation Reactive Service rates are charged to all users of the Network and Interties on the same basis as their transmission service. The billing determinant is all forecasted long-term and short-term use of the Network and Southern Intertie, excluding FPT use. Table 7, lines 7.3-7.4. For the Generation Reactive rate, the total billing determinant is also adjusted for forecasted self-supply of Generation Reactive. Self-supply of Generation Reactive is limited to resources that meet specified criteria, and is estimated at 1,125 MW. Table 7, line 7.6. The resulting Scheduling rate is \$0.164/kW/month, and the Generation Reactive rate is \$0.066/kW/month. The rates are structured so that they may be used in conjunction with NT transmission service and PTP transmission service (PTP, IS, and IM rates), and can be applied to all long-term and short-term uses of the transmission system. *See* section 2.4.2 for a description of the PTP rate design.

2.4.2 <u>Network and Southern Intertie Rates</u>

After the two required Ancillary Service rates are calculated, the remaining Network rates (IR, PTP, and NT) and the Southern Intertie (IS) rate are calculated. *See* Table 8. First, the Base Charge (PTP, NT) of \$1.013/kW/month is calculated by subtracting the two Ancillary Service rates from the Settlement Agreement cap of \$1.243/kW/month. The IR rate is set at the Settlement Agreement cap of \$1.243/kW/month. The NT Load Shaping Charge is the Settlement Agreement NT cap of \$1.647/kW/month less the \$1.243/kW/month cap. The IS rate of \$1.159/kW/month is calculated by subtracting the two Ancillary Service rates from the Settlement Agreement IS cap of \$1.389/kW/month.

Next, the PTP and IS daily Block 1 rate (first five days of a reservation), daily Block 2 rate (day 6 and beyond of a reservation), and the hourly rate are calculated. The Block 1 daily rate is calculated by dividing the annual rate by 365 days and 5/7, and the Block 2 daily rate is calculated by dividing the annual rate by 365 days. The hourly rate is calculated by dividing the annual rate by the number of peak hours in the year (5 days per week, 16 hours per day).

2.4.3 Montana Intertie and Eastern Intertie Rates

The Montana Intertie rate for long-term service, $14.87/kW/year, equals BPA-TBL's payment under the TGT rate for the Montana Intertie facilities divided by BPA-TBL's capacity allocation of 185 MW. The IM daily and hourly rates are calculated using the same method described in section 2.4.2. *See* Table 9.

The IE rate for nonfirm service is set at the level calculated in the Initial Proposal, 1.38 mills/kWh. The basis for this rate was the Eastern Intertie segment cost divided by the forecast amount of Colstrip energy. *See* TR-02-E-BPA-03, at Table 9. This rate is set pursuant to the Montana Intertie Agreement.

2.4.4 Delivery Charge

The Delivery Charge is charged to transmission customers taking delivery of power, either Federal or non-Federal, over transformers that are in the Utility or DSI Delivery Segments. The Utility Delivery Charge is set at the level specified in the Settlement

Agreement, \$0.932/kW/month. The DSI Delivery Charge uses the UFT method to determine the charge to the customer.

3. TRANSMISSION AND ANCILLARY SERVICE RATE SCHEDULES

3.1 <u>Formula Power Transmission Rates (FPT-02.1 and FPT-02.3)</u>

The FPT-02.1 and FPT-02.3 rates are available for firm transmission of 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 FPT rates include a distance component for transmission lines and various transformation and terminal charges. The FPT-02.1 rate is used for contracts allowing annual rate adjustments. The FPT-02.3 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 Power Factor Penalty Charge, the Failure to Comply Penalty Charge, and notice regarding ancillary services. <u>*See*</u> section 3.10 for further discussion of these provisions.

3.2 <u>Integration of Resources Rate (IR-02)</u>

The proposed IR-02 rate is a "postage stamp" rate (independent of distance) consisting of a monthly demand charge. 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. Upon agreement, the IR service may be applied to points of delivery at an intertie.

Nonfirm wheeling from alternate Points of Integration, up to the contractually specified total Transmission Demands, may be done at the IR rate pursuant to IR contract provisions, and 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 IR demand charge is Total Transmission Demand. IR service does not allow assignment of Transmission Demand to third parties.

BPA-TBL proposes to continue the Short Distance Discount (SDD) which decreases the IR rate 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 SDD rate equals i) the component of the IR Base rate associated with Ancillary Services, plus ii) a charge determined by multiplying the transmission-related component of the IR Base rate by the following formula:

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

The IR rate schedule also includes the Power Factor Penalty Charge, the Delivery Charge, the Failure to Comply Penalty Charge, and provisions detailing the circumstances under which the Ratchet Demand may be waived or reduced. *See* section 3.10 for further discussion of these provisions. The rate schedule also includes a provision that allows IR customers to receive a credit for self-supply of Generation Reactive Service on an equivalent basis to the credit for PTP customers.

3.3 Network Integration Rate (NT-02)

The proposed NT-02 rate applies to Transmission Customers taking Network Integration Service under the OATT. NT Service provides transmission service for a customer's retail load. Charges for use of the Network include a Base Charge and a 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 Unauthorized Increase Charge for NT Service is applied to the difference between the Actual and Declared CSL.

The NT 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.

The NT-02 rate schedule also includes a variety of adjustments, charges and other rate provisions, including: a requirement to purchase Scheduling and Generation Reactive ancillary services; the Delivery Charge; the Unauthorized Increase Charge; the Power Factor Penalty Charge; the Failure to Comply Penalty Charge; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 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 and a Metering Adjustment for Points of Delivery that do not have hourly demand meters.

3.4 Point-to-Point Rate (PTP-02)

The proposed PTP-02 rate schedule applies to transmission customers taking PTP Transmission Service under the OATT. PTP Transmission Service may be used to serve native load and transactions with third parties over Network and Delivery facilities. The proposed PTP-02 rate includes a monthly rate for Long-Term Firm service, and downwardly flexible rates that apply to Short-Term Firm and Non-Firm service on the Network. The PTP-02 rate schedule includes all rates for all PTP services on the Network. Under the 1996 rates, PTP service on the Network is available 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. These three 1996 rate schedules are combined into one rate schedule for 2002.

The PTP-02 rate schedule provides two rates for short-term monthly, weekly, and daily service—one for the first five days of a reservation, and the other for the remaining days of the reservation. For reservations with a duration greater than five days, one charge will be applied to the first five days of the reservation, and a second charge to the remaining days of the reservation. One hourly rate applies to reservations for hourly firm and non-firm service.

The PTP-02 rate schedule continues to include a Short-Distance Discount which is very similar to the SDD in the IR rate. The PTP rate schedule also includes: a requirement to purchase Scheduling and Generation Reactive ancillary services; the Delivery Charge; the Power Factor Penalty Charge; an Unauthorized Increase Charge; the Reservation Fee; the Failure to Comply Penalty Charge; a credit for interruption of daily, weekly, and monthly nonfirm service; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 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 Intertie Service: Southern Intertie Rate (IS-02) and Montana Intertie Rate (IM-02)**

The IS-02 and IM-02 rate schedules apply to transmission customers taking PTP Transmission Service on the Southern Intertie and Montana Intertie, respectively, under the terms and conditions of the OATT. In addition, the IS rate schedule applies to transmission contracts for Southern Intertie service in effect prior to October 1, 1996.

The IM rate provides for service over BPA's 185 MW of Montana Intertie capacity rights. The IS and IM rate schedules include rates for long-term firm service, and short-term firm and nonfirm service. The short-term firm and nonfirm rates are caps that are downwardly flexible. Similar to the PTP-02 rate schedule, the IS-02 and IM-02 rate schedules provide blocked rates for short-term firm and nonfirm service.

The IS and IM rate schedules also include: the requirement to purchase certain ancillary services; a credit for interruption of daily, weekly, and monthly nonfirm service; the Reservation Fee; the Power Factor Penalty Charge; an Unauthorized Increase Charge; the Failure to Comply Penalty Charge; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 for further discussion of these provisions. Finally, the rate schedules provide notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.6 Townsend-Garrison Transmission Rate (TGT-02) and Eastern Intertie Rate (IE-02)

The proposed TGT and IE rates are based on provisions of the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended). The TGT-02 rate recovers the cost of the Townsend-Garrison facilities. The IE-02 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. Revenue from these transactions is treated as a revenue credit against the TGT rate.

3.7 Use-of-Facilities Transmission Rate (UFT-02)

Wheeling transactions over specifically identified facilities occur under the UFT-02 formula-based rate. The UFT rate schedule provides for charges that vary with the customer's monthly use of the facilities, as well as charges designed to recover a fixed amount of costs from a customer regardless of how the customer's load may vary over the year. In addition, the Power Factor Penalty Charge and notice regarding ancillary services is included in the rate schedule.

3.8 Advance Funding Rate (AF-02)

This rate schedule allows BPA-TBL 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 may include interconnection and resource integration facilities, and FCRTS upgrades, reinforcements, and replacements. 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.

3.9 Ancillary Services and Control Area Service Rate Schedule (ACS-02)

The proposed ACS-02 rate schedule includes rates for the six required Ancillary Services and four Control Area services. All transmission contract holders must satisfy the reliability requirements associated with their energy transactions, whether energy is delivered into, out of, within, or through the BPA Control Area. Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. BPA-TBL, as the Transmission Provider, is required to provide, and Transmission Customers are required to purchase, the Ancillary Services of Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control from Generation Sources. BPA-TBL is required to offer to provide the following Ancillary Services to Transmission Customers serving load or integrating generation within the BPA Control Area: Regulation and Frequency Response; Energy Imbalance; Operating Reserve – Spinning; and Operating Reserve - Supplemental. The Transmission Customer serving load or integrating generation within the BPA Control Area is required to acquire these Ancillary Services, whether from the BPA-TBL, from a third party, or by self-supply.

Control Area Service rates apply to transactions in the BPA Control Area for which the reliability obligations have not been met through Ancillary Services or some other arrangement. The four CAS rates are Load Regulation and Frequency Response Service; Generation Imbalance Service; Operating Reserve -- Spinning Reserve Service; and Operating Reserve – Supplemental Reserve Service. To the extent that resources or loads in the BPA Control Area do not otherwise satisfy the reliability obligations that their energy transactions impose on the BPA Control Area, Control Area Services must be purchased from BPA-TBL.

All rates in the ACS-02 rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA Section 212.

3.9.1 <u>Scheduling, System Control, and Dispatch (Scheduling) Service</u>

Scheduling Service is necessary to the provision of basic transmission service within every control area. This service can be provided only by the operator of the control area in which the transmission facilities used are located. This is because the service is to schedule the movement of power through, out of, within, or into the control area. Scheduling Service also includes the dispatch of generating resources to maintain generation/load balance and maintain security during the transaction.

The rates in section II.A of the ACS-02 rate schedule apply to all transmission transactions under the OATT. Transactions on the Network and Interties are each charged separately for this service on the same basis as they are charged for their transmission service: capacity reservations for PTP (Network, Southern Intertie, Montana Intertie) customers; and the Base Charge billing factor for NT customers. The rate charges are structured to correspond to the various transmission services available – long-term firm, short-term firm and non-firm service. Thus, the Scheduling charge for long-term firm service applies to NT and long-term PTP service. The short-term firm and nonfirm Scheduling charges apply to short-term firm and nonfirm PTP transmission service. All charges are downwardly flexible; any discounts would be offered consistent with section II.F of the GRSPs.

3.9.2 Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service

Generation Reactive Service is the provision of reactive power and voltage control by generating facilities under the control of the BPA-TBL. This service is necessary to the provision of basic transmission service within every control area.

The rates in section II.B of the ACS-02 rate schedule apply to all transmission transactions under the OATT. The description of the Scheduling Service rate schedule, above, also applies to the Generation Reactive rate schedule. In addition, the Generation Reactive Service rate includes a billing factor provision that recognizes that under some circumstances this Service may, in part, be self-provided.

3.9.3 Regulation and Frequency Response (Regulation) Service

Regulation Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the BPA-TBL. The BPA-TBL must offer this service when the transmission service is used to serve load within the BPA Control Area. The transmission customer must either purchase this service from the BPA-TBL or make alternative comparable arrangements to satisfy its Regulation Service obligation.

Customers may be able to satisfy the Regulation Service obligation by providing generation with automatic generation control capabilities to the BPA-TBL.

The Regulation Service rate in section II.C of the ACS-02 rate schedule provides an energy charge to be applied to the customer's load in the BPA Control Area. The charge is downwardly flexible; any discounts would be offered consistent with section II.F of the GRSPs.

3.9.4 <u>Energy Imbalance Service</u>

Energy Imbalance Service is for transmission within and into the BPA Control Area to serve load in the Control Area. Energy Imbalance represents the deviation between the scheduled and actual delivery of energy to a load in the BPA Control Area over a single hour.

All Transmission Customers serving load in the BPA Control Area are subject to charges for Energy Imbalance. The Energy Imbalance rate in section II.D of the ACS-02 rate schedule establishes an imbalance deviation band. If deviations between customers' loads and schedules stay within the imbalance deviation band, customers are only required to return the energy at a later time. A deviation account is used to sum the positive and negative deviations from schedule over all schedule hours. Once a month this account must be settled (brought to zero). BPA-TBL will designate the time and amounts to be delivered to accomplish the settlement. The customer will arrange for and schedule the delivery.

If actual loads are greater than schedules by more than the greater of 2 MW or 1.5%, a penalty rate applies. For these deviations in excess of the energy imbalance band, the rate is the higher of 100 mills per kWh or 110% of BPA's incremental cost. BPA's incremental cost will be a market-based rate determined by an hourly energy index in the PNW. If actual loads are less than schedules by more than 2 MW or 1.5%, the customer will receive a credit for the excess energy equal to 90% of the market rate, provided that the deviation was not an Intentional Deviation and the Federal System was not in Spill Condition during the month.

3.9.5 Operating Reserve -- Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA-TBL must offer this service when the transmission service is used to serve firm load (inside or outside of the BPA Control Area) from generation located in the BPA Control Area. The Transmission Customer must either purchase this service from BPA-TBL or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer's obligation is determined consistent with North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and Northwest Power Pool (NWPP) criteria.

The Spinning Reserve Service rate, section II.E of the ACS-02 rate schedule, includes two components. The first component is an energy charge that is applied to the customer's Spinning Reserve Requirement. This rate of 8.27 mills/kWh recovers the cost of having generation available to respond to a system contingency. The Spinning Reserve Requirement is determined, based on current WSCC and NWPP standards, as 2.5% of the hydroelectric generation and 3.5% of the non-hydroelectric generation located in the BPA Control Area used to serve the transmission customer's firm load. The Spinning Reserve Requirement will be adjusted when and if WSCC and NWPP standards change. The Spinning Reserve charge is downwardly flexible; any discounts would be offered consistent with section II.F of the GRSPs.

The second Spinning Reserve Service rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by the BPA-TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

3.9.6 <u>Operating Reserve -- Supplemental Reserve Service</u>

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. The BPA-TBL must offer this service when the transmission service is used to serve firm load (inside or outside the BPA Control Area) from generation located in the BPA

Control Area. The Transmission Customer must either purchase this service from the BPA-TBL or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission customer's obligation is determined consistent with NERC, WSCC and NWPP criteria.

The Supplemental Reserve Service rate, section II.F of the ACS-02 rate schedule, is the same as the Spinning Reserve Service rate described above with one exception. The Billing Factor for the Supplemental Reserve Requirement includes an additional factor accounting for power scheduled into the BPA Control Area that is interruptible on 10 minute's notice, consistent with current WSCC and NWPP standards.

3.9.7 <u>CAS Regulation and Frequency Response Service</u>

The Control Area Service Regulation and Frequency Response is the same technical service, at the same rate, as the Ancillary Service so named. The difference is, the Control Area Service is offered to loads in the BPA Control Area that may not be taking BPA basic transmission service. Loads served by generation "behind the meter" are an example. Unless that load is receiving Regulation and Frequency Response Service to the same quality standards BPA uses for its service from the "behind the meter" generation, the BPA Control Area is in fact providing the service to that load. Reliability standards established by WSCC applied to the BPA Control Area result in BPA operating sufficient regulating reserves to cover the requirements of all Control Area load. Each load in the Control Area must purchase an amount to cover the obligation it imposes upon the Control Area. To the extent that loads are not otherwise receiving this service, it must be purchased from the BPA Control Area. The ACS-02 rate schedule identifies the energy charge to be applied to load in the BPA Control Area.

3.9.8 CAS Generation Imbalance Service

Generation_Imbalance Service provides or absorbs energy to meet the difference between scheduled and actual generation delivered to the BPA Control Area from generators located in the BPA Control Area. All generators in the BPA Control Area are subject to charges for Generation Imbalance Service. The Generation Imbalance Service rate in section III.B of the ACS-02 rate schedule establishes an imbalance deviation band. If the difference between a generator's schedule and its delivery stays within the imbalance deviation band, the only requirement is return of energy at a later time. A deviation account is used to sum the positive and negative deviations from schedule over all schedule hours. Once a month this account must be settled (brought to zero). BPA-TBL will designate the time and amounts to accomplish the settlement. The generator will arrange for and schedule the delivery.

If actual generation is less than schedule by more than 2 MW or 1.5%, a penalty rate applies. For these deviations in excess of the generation imbalance deviation band, the rate is the higher of 100 mills/kWh or 110% of BPA's incremental cost. BPA's incremental cost will be a market- based rate determined by an hourly energy index in the PNW. If actual generation exceeds the schedule by more than 2 MW or 1.5%, the customer will receive a credit for the excess energy equal to 90% of the market rate, provided that the deviation was not an Intentional Deviation and the Federal System was not in Spill Condition during the month.

3.9.9 <u>CAS Operating Reserve -- Spinning Reserve Service</u>

The Control Area Service Operating Reserve -- Spinning Reserve Service is the same technical service, at the same rate, as the Ancillary Service so named. The difference is that the Control Area Service is taken by generators in the BPA Control Area which may not have a Transmission Contract with BPA, but have energy transactions which impose a spinning reserve obligation on the BPA Control Area. The generator's obligation is determined consistent with NERC, WSCC, and NWPP criteria. To the extent that Spinning Reserve Service is not otherwise provided to cover the generator's Spinning Reserve obligation (through Ancillary Service purchases or self-supply, for example), the Control Area Service is provided and must be purchased.

The Spinning Reserve Service rate, section III.C of the ACS-02 rate schedule, includes two components. The first component is an energy charge that is applied to the customer's Spinning Reserve Requirement. This rate of 8.27 mills/kWh recovers the cost of having generation available to respond to a system contingency. The Spinning Reserve Requirement is determined, based on current WSCC and NWPP standards, as 2.5% of the hydroelectric generation and 3.5% of the non-hydroelectric generation located in the BPA Control Area used to serve the firm load responsibility. The Spinning Reserve Requirement will be adjusted when and if WSCC and NWPP standards change.

The second Spinning Reserve Service rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by the BPA-TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

3.9.10 CAS Operating Reserve -- Supplemental Reserve Service

The Control Area Service Operating Reserve -- Supplemental Reserve Service is the same technical service, at the same rate, as the Ancillary Service so named. The difference is that the Control Area Service is taken by generators in the BPA Control Area which may not have a Transmission Contract with BPA, but have energy transactions which impose a supplemental reserve obligation on the BPA Control Area. The generator's obligation is determined consistent with NERC, WSCC, and NWPP criteria. To the extent that Supplemental Reserve Service is not otherwise provided to cover the generator's Supplemental Reserve obligation (through Ancillary Service purchases or self-supply, for example), the Control Area Service is provided and must be purchased.

The Supplemental Reserve Service rate, section III.D of the ACS-02 rate schedule, is the same as the Spinning Reserve Service rate described above with one exception. The Billing Factor for the Supplemental Reserve Requirement (section II.F.2.a) includes an additional factor accounting for any power scheduled into the BPA Control Area that is interruptible on 10 minute's notice, consistent with current WSCC and NWPP standards.

3.10 Other Charges and Provisions

3.10.1 Delivery Charge

The Delivery Charge, section II.A of the GRSPs, is applied to deliveries of power over Delivery facilities as defined by the DSI Delivery and Utility Delivery segments. The Delivery Charge includes separate rates for service over DSI Delivery and Utility Delivery facilities.

The DSI Delivery Charge uses the UFT-02 rate to determine the fixed monthly payment. The DSI Delivery Charge is designed to be independent of the actual DSI load; the charge is assessed whether or not the DSI is operating. If the DSI Delivery facilities serve only a DSI load and no other BPA-TBL customers, the UFT charge will be a sole use charge; i.e., the total annual cost associated with the facilities determined in accordance with section III.B.1 of the UFT-02 rate schedule. If the DSI Delivery facilities serve more than one customer, the UFT charge will be based on the total annual cost associated with the facilities prorated between or among the customers using the delivery facilities in accordance with section III.B.2 of the UFT-02 rate schedule. The annual cost (total or prorated) will be divided by 12 to calculate the monthly DSI Delivery Charge.

The Utility Delivery Charge, \$0.932/kW/month, is assessed on the demand on the Utility Delivery facilities on the hour of the Monthly Transmission Peak Load.

3.10.2 Failure to Comply Penalty Charge

The Failure to Comply Penalty, found in section II.B of the GRSPs, will be assessed to parties that fail to properly respond to a curtailment, redispatch, or load shedding order from BPA-TBL. This includes, without limitation, failure of generators in the BPA Control Area or which directly connect to the FCRTS to change generation when directed to do so by BPA-TBL; failure to shed load in accordance with the OATT or any applicable agreements between BPA-TBL and the party; failure to curtail a schedule; and failure to respond to BPA-TBL operational orders in the time period specified by regional reliability criteria.

3.10.3 Power Factor Penalty Charge

BPA-TBL proposes to continue charging customers for their excessive reactive power requirements. The Power Factor Penalty Charge, found in section II.C of the GRSPs and included in the transmission rate schedules, will replace the current Reactive Power Charge in the 1996 rate schedules. The customer will be billed directly for measured quantities of reactive demand which fall outside a specified deadband. The deadband equals 25% of the highest real power demand (based on a 0.97 power factor) at the Point of Interconnection (POI) during the billing month. The Power Factor Penalty Charge applies only to lagging reactive demand during Heavy Load Hours and only to leading reactive demand during Light Load Hours. An eleven-month ratchet will be applied to the demand charge. There will be separate ratchets for leading and lagging reactive demand.

The Power Factor Penalty Charge is applied hourly to each POI between BPA-TBL and parties interconnected to the FCRTS. 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.

The purpose of the Power Factor Penalty Charge is to provide an incentive to minimize preventable reactive flows at interconnections with the FCRTS. 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. The proposed rate is the per unit installed cost of reactors and capacitors, and is calculated by dividing the annual cost of the respective facilities by the installed capacity to get cost per kVAr. This is then multiplied by the penalty factor of two. Calculation of the Power Factor Penalty Charge is shown in Appendix I.

3.10.4 Rate Adjustment Due to FERC Order Under FPA §212

This provision, found in section II.D of the GRSPs, is included in the NT, PTP, IS, IM, and ACS rate schedules, which are designed to offer OATT 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.

3.10.5 Reservation Fee

The Reservation Fee, found in section II.E of the GRSPs, is included in the PTP, IS, and IM rate schedules. The Reservation Fee is applicable to PTP Transmission Customers who want to postpone the commencement of service by reserving "deferred" service for long-term PTP service through an advanced reservation, or requesting an extension of the Service Commencement Date specified in the executed Service Agreement. "Deferred" service is an advance reservation of long-term PTP service with a Service Commencement Date greater than one year from the request date. The Reservation Fee is a nonrefundable fee equal to one month's charge for each year or fraction of a year for which the customer chooses to postpone service. For customers extending the Service Commencement Date; if BPA-TBL 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.

3.10.6 Transmission and Ancillary Services Rate Discounts

All transmission and ancillary service rates for service under the OATT may be discounted consistent with FERC policy and to the extent provided for in the relevant rate schedule. FERC requirements for applying discounts for specified in section II.F of the GRSPs.

3.10.7 Unauthorized Increase Charge

For rate schedules under the PTP tariff (PTP, IS, and IM rates) and the NT tariff (NT rate), BPA-TBL proposes to assess an Unauthorized Increase Charge (UIC) if PTP Transmission Service customers exceed their capacity reservations, or if an NT customer's Actual CSL is less than its Declared CSL on the monthly billing hour. The UIC, found in section II.G of the GRSPs, is set at four times the annual PTP rate, or $4.052/kW/month. Consistent with the Settlement Agreement, provision for waiving or reducing the UIC has been added.

For PTP service, BPA-TBL will determine unauthorized increases during all hours at the customer's PODs and PORs, the highest of which will be the billing factor for the UIC. Measurement of actual demands for one-way dynamically scheduled resources will be based on a 10-minute moving average measure; for two-way dynamic schedules, actual demands will be the instantaneous peak demand for the hour. The demands associated with all other schedules will be based on the 60-minute integrated demands or transmission schedules.

3.10.8 Incremental Cost Rates

BPA-TBL provides notice in most of the firm rate schedules that requests for new or increased firm transmission service that would require BPA-TBL 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. BPA-TBL 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.

3.10.9 GTA Delivery Charge

The GTA Delivery Charge, section II.H of the GRSPs, is a BPA-PBL charge for delivery of Federal power over non-Federal low-voltage facilities. As provided in the Settlement Agreement, this charge is set at the same level and charged at the same billing factor as the Utility Delivery Charge.

TABLES

Table 1
Transmission Revenue Requirements
($000)

		(A) TBL	(B) Generation	(C)	(D) Delivery	(E) Delivery	(F) Intertie	(G) Intertie	(H) Ancillary
		Total	Integration	Network	Utility	Industry	Southern	Eastern	Services
	FY 2002								
1. 1	Gross Plant	4,801,203	62,361	3,485,401	67,147	59,577	689,410	123,670	313,637
1. 2	Lines	2,187,952	16,398	1,867,778	1,260	1,200	202,494	98,822	
1. 3	Stations	2,299,614	45,963	1,617,623	65,887	58,377	486,916	24,848	
1. 4	Net Plant	3,136,059	49,881	2,265,598	56,451	49,691	418,586	80,001	215,851
1. 5	Operating Expenses	228,419	2,335	147,587	4,509	2,559	25,476	2,048	43,905
1. 6	Generation Inputs								
1. 7	Ancillary Services	71,664							71,664
1. 8	Station Service	1,724	30	1,133	98	56	399	8	
1. 9	Corp/Bureau	3,701		3,478	223				
1.10	Remedial Action Scheme (RAS)	231					231		
1.11	Gen'l Transfer Agrmnts for nonfederal pwr	2,000		2,000					
1.12	Leases	5,267		5,188	79				
1.13	Depreciation	181,734	2,402	119,986	2,675	2,427	26,371	4,062	23,811
1.14	Interest Credit from Facilities Sales	-752	0	0	-376	-376	0	0	0
1.15	Interest	177,060	2,816	127,914	3,187	2,806	23,633	4,517	12,187
1.16	Net Revenues for Risk	0	0	0	0	0	0	0	0
1.17	Total Cost	671,048	7,583	407,286	10,395	7,472	76,110	10,635	151,567

Table 1
Transmission Revenue Requirements
($000)

		(A) TBL Total	(B) Generation Integration	(C) Network	(D) Delivery Utility	(E) Delivery Industry	(F) Intertie Southern	(G) Intertie Eastern	(H) Ancillary Services
	FY 2003								
1.18	Gross Plant	4,929,534	63,020	3,678,284	69,046	61,476	694,354	26,750	336,604
1.19	Lines	2,190,961	16,511	1,965,664	1,656	1,596	203,938	1,596	
1.20	Stations	2,401,969	46,509	1,712,620	67,390	59,880	490,416	25,154	
1.21	Net Plant	3,206,660	48,224	2,359,217	56,001	49,506	400,961	76,598	216,153
1.22	Operating Expenses	222,543	2,276	143,848	4,394	2,494	24,832	1,996	42,703
1.23	Generation Inputs								
1.24	Ancillary Services	71,664							71,664
1.25	Station Service	1,724	30	1,133	98	56	399	8	
1.26	Corp/Bureau	3,684		3,458	226				
1.27	Remedial Action Scheme (RAS)	231					231		
1.28	Gen'l Transfer Agrmnts for nonfederal pwr	2,000		2,000					
1.29	Leases	5,267		5,188	79				
1.30	Depreciation	194,009	2,473	128,861	2,803	2,548	27,065	4,161	26,098
1.31	Interest Credit from Facilities Sales	-750	0	0	-375	-375	0	0	0
1.32	Interest	178,865	2,690	131,595	3,124	2,761	22,365	4,273	12,057
1.33	Net Revenues for Risk	0	0	0	0	0	0	0	0
1.34	Total Cost	679,237	7,469	416,083	10,349	7,484	74,892	10,438	152,522
	Average FY 2002 and FY 2003								
1.35	Total Cost	675,143	7,526	411,685	10,372	7,478	75,501	10,537	152,045

Table 2
Revenue Credits

		(A) FY 2002 ($000)	(B) FY 2003 ($000)	(C) AVERAGE ($000)
	Transmission Revenue Credit			
2. 1	AC Rate	1,375	1,375	1,375
2. 2	CSPE Whlg	268	127	198
2. 3	Fiber	15,500	17,500	16,500
2. 4	Fiber Depreciation	696	696	696
2. 5	Irrigation Pumping Power	1,288	1,288	1,288
2. 6	NFP Depreciation	3,335	3,335	3,335
2. 7	Operations and Maintenance	675	675	675
2. 8	PC Wireless	4,070	4,430	4,250
2. 9	Power Factor Penalty Charge	5,000	5,000	5,000
2.10	Remedial Action Scheme (RAS)	597	597	597
2.11	Supplemental Capacity Whlg	62	27	45
2.12	TGT	10,136	10,136	10,136
2.13	Use of Facilities (UFT)	5,679	5,679	5,679
2.14	Reservation Fee	828	1,656	1,242
2.15	PBL Delivery Credit	2,000	2,000	2,000
2.16	Total	48,681	50,865	49,773

Credit Segmentation Factors (decimals)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Generation		Delivery		Intertie		Ancillary
		Total	Integration	Network	Utility	Industrial	Southern	Eastern	Services
2.17	AC Rate	1.0000	-	-	-	-	1.0000	-	-
2.18	CSPE Whlg	1.0000	0.0364	0.9497	0.0138	-	-	-	-
2.19	Fiber	1.0000	0.0115	0.5399	0.0131	0.0116	0.0957	0.0183	0.3100
2.20	Fiber Depreciation	1.0000	0.0115	0.5399	0.0131	0.0116	0.0957	0.0183	0.3100
2.21	Irrigation Pumping Power	1.0000	-	1.0000	-	-	-	-	-
2.22	NFP Depreciation	1.0000	-	-	-	-	1.0000	-	-
2.23	Operations and Maintenance	1.0000	0.0159	0.9674	0.0116	0.0000	0.0051	-	-
2.24	PC Wireless	1.0000	-	1.0000	-	-	-	-	-
2.25	Power Factor Penalty Charge	1.0000	-	1.0000	-	-	-	-	-
2.26	Remedial Action Scheme (RAS)	1.0000	-	-	-	-	1.0000	-	-
2.27	Supplemental Capacity Whlg	1.0000	0.0370	0.9630	-	-	-	-	-
2.28	TGT	1.0000	-	0.0282	-	-	-	0.9718	-
2.29	Use of Facilities (UFT)	1.0000	0.0012	0.7145	0.0497	-	0.1560	0.0786	-
2.30	Reservation Fee	1.0000	-	0.8000	-	-	0.2000	-	-
2.31	PBL Delivery Credit	1.0000	-	-	1.0000	-	-	-	-

Table 2
Revenue Credits
($000)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Generation		Delivery		Intertie		Ancillary
		Integration	Network	Utility	Industrial	Southern	Eastern	Services
FY 2002 Revenue								
2.32	AC Rate	-	-	-	-	1,375	-	-
2.33	CSPE Whlg	10	255	4	-	-	-	-
2.34	Fiber	178	8,368	203	179	1,483	283	4,805
2.35	Fiber Depreciation	8	376	9	8	67	13	216
2.36	Irrigation Pumping Power	-	1,288	-	-	-	-	-
2.37	NFP Depreciation	-	-	-	-	3,335	-	-
2.38	Operations and Maintenance	11	653	8	0	3	-	-
2.39	PC Wireless	-	4,070	-	-	-	-	-
2.40	Power Factor Penalty Charge	-	5,000	-	-	-	-	-
2.41	Remedial Action Scheme (RAS)	-	-	-	-	597	-	-
2.42	Supplemental Capacity Whlg	2	60	-	-	-	-	-
2.43	TGT	-	285	-	-	-	9,850	-
2.44	Use of Facilities (UFT)	7	4,057	282	-	886	446	-
2.45	Reservation Fee	-	662	-	-	166	-	-
2.46	PBL Delivery Credit	-	-	2,000	-	-	-	-
2.47	**Subtotal FY 2002**	**215**	**25,074**	**2,506**	**188**	**7,912**	**10,593**	**5,021**
FY 2003 Revenue								
2.48	AC Rate	-	-	-	-	1,375	-	-
2.49	CSPE Whlg	5	121	2	-	-	-	-
2.50	Fiber	200	9,448	230	203	1,674	320	5,425
2.51	Fiber Depreciation	8	376	9	8	67	13	216
2.52	Irrigation Pumping Power	-	1,288	-	-	-	-	-
2.53	NFP Depreciation	-	-	-	-	3,335	-	-
2.54	Operations and Maintenance	11	653	8	0	3	-	-
2.55	PC Wireless	-	4,430	-	-	-	-	-
2.56	Power Factor Penalty Charge	-	5,000	-	-	-	-	-
2.57	Remedial Action Scheme (RAS)	-	-	-	-	597	-	-
2.58	Supplemental Capacity Whlg	1	26	-	-	-	-	-
2.59	TGT	-	285	-	-	-	9,850	-
2.60	Use of Facilities (UFT)	7	4,057	282	-	886	446	-
2.61	Reservation Fee	-	1,324	-	-	331	-	-
2.62	PBL Delivery Credit	-	-	2,000	-	-	-	-
2.63	**Subtotal FY 2003**	**231**	**27,009**	**2,531**	**211**	**8,269**	**10,629**	**5,641**

Table 2
Revenue Credits
($000)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Generation		Delivery		Intertie		Ancillary
		Integration	Network	Utility	Industrial	Southern	Eastern	Services
Two Year Average, FY 2002 and FY 2003								
2.64	AC Rate	-	-	-	-	1,375	-	-
2.65	CSPE Whlg	7	188	3	-	-	-	-
2.66	Fiber	189	8,908	217	191	1,579	302	5,115
2.67	Fiber Depreciation	8	376	9	8	67	13	216
2.68	Irrigation Pumping Power	-	1,288	-	-	-	-	-
2.69	NFP Depreciation	-	-	-	-	3,335	-	-
2.70	Operations and Maintenance	11	653	8	0	3	-	-
2.71	PC Wireless	-	4,250	-	-	-	-	-
2.72	Power Factor Penalty Charge	-	5,000	-	-	-	-	-
2.73	Remedial Action Scheme (RAS)	-	-	-	-	597	-	-
2.74	Supplemental Capacity Whlg	2	43	-	-	-	-	-
2.75	TGT	-	285	-	-	-	9,850	-
2.76	Use of Facilities (UFT)	7	4,057	282	-	886	446	-
2.77	Reservation Fee	-	993	-	-	248	-	-
2.78	PBL Delivery Credit	-	-	2,000	-	-	-	-
2.79	**Average of FY 2002 and FY 2003**	**223**	**26,041**	**2,519**	**199**	**8,090**	**10,611**	**5,331**

Table 3
Rate Development Costs
($000/Yr)

		(A)	(B)	(C)	(D)	(F)	(G)	(H)
		Generation		Delivery		Intertie		Ancillary
		Integration	Network	Utility	Industry	Southern	Eastern	Services
	FY 2002							
3. 1	Unadjusted Costs (Table 1)	7,583	407,286	10,395	7,472	76,110	10,635	151,567
3. 2	Revenue Credits (Table 2)	-215	-25,074	-2,506	-188	-7,912	-10,593	-5,021
3. 3	DSI Stability Reserves 1/	0	0	0	0	542	0	0
3. 4	Eastern Intertie Adjustment 2/	1	31	1	1	6	-42	3
3. 5	DSI Delivery Underrecovery	0	1,495	0	-1,495	0	0	0
3. 6	Total	7,369	383,738	7,889	5,790	68,746	0	146,549
	FY 2003							
3. 7	Unadjusted Costs (Table 1)	7,469	416,083	10,349	7,484	74,892	10,438	152,522
3. 8	Revenue Credits (Table 2)	-231	-27,009	-2,531	-211	-8,269	-10,629	-5,641
3. 9	DSI Stability Reserves 1/	0	0	0	0	544	0	0
3. 10	Eastern Intertie Adjustment 2/	-3	-144	-3	-3	-25	191	-13
3. 11	DSI Delivery Underrecovery	0	1,480	0	-1,480	0	0	0
3. 12	Total	7,235	390,410	7,815	5,790	67,143	0	146,868
	Average FY 2002 and FY 2003							
3.12	Unadjusted Costs (Table 1)	7,526	411,685	10,372	7,478	75,501	10,537	152,045
3.13	Revenue Credits (Table 2)	-223	-26,041	-2,519	-199	-8,090	-10,611	-5,331
3.14	DSI Stability Reserves 1/	0	0	0	0	543	0	0
3.15	Eastern Intertie Adjustment 2/	-1	-56	-1	-1	-9	75	-5
3.16	DSI Delivery Underrecovery	0	1,487	0	-1,487	0	0	0
3.17	Total	7,302	387,074	7,852	5,790	67,944	0	146,709

1/ Stability reserves credit based on DSI smelter load of 2855 MW (2002) and 2868 MW (2003) times credit of $0.01582/kW-mo.
2/ Eastern Intertie adjustment (cost - revenue) segmented on Table 1 net plant percentages.

Table 4
Long-Term Transmission Sales
(Megawatts)

	Transmission Rate Schedule	Units 1/	(A) Oct	(B) Nov	(C) Dec	(D) Jan	(E) Feb	(F) Mar	(G) Apr	(H) May	(I) Jun	(J) Jul	(K) Aug	(L) Sep	(M) Annual Average
	Network														
	FY 2002														
4. 1	Formula Power Transmission (FPT)	a_cd	3,429	3,429	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,429	**3,405**
4. 2	Integration of Resources (IR)	a_cd	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	**4,542**
4. 3	Point to Point (PTP)	a_cd	10,881	10,881	10,881	10,886	10,886	11,156	11,156	11,156	11,156	11,156	11,156	11,156	**11,042**
4. 4	Point to Point (PTP) 2/	m_cd	1,645	1,557	1,557	1,557	1,557	1,557	1,579	1,682	1,710	1,549	1,387	1,387	**1,560**
4. 5	Network Integration (Base Charge)	cp	4,990	5,046	6,063	6,291	6,272	5,090	4,590	4,194	4,016	4,419	4,528	4,145	**4,970**
4. 6	Subtotal Network		25,488	25,456	26,440	26,673	26,654	25,742	25,264	24,971	24,821	25,063	25,010	24,660	**25,520**
	FY 2003														
4. 7	Formula Power Transmission (FPT)	a_cd	3,429	3,429	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,396	3,429	**3,405**
4. 8	Integration of Resources (IR)	a_cd	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	4,542	**4,542**
4. 9	Point to Point (PTP)	a_cd	11,831	11,831	11,831	11,645	11,645	11,645	11,645	11,645	11,645	11,535	11,535	11,535	**11,664**
4.10	Point to Point (PTP) 2/	m_cd	1,519	1,431	1,431	1,431	1,431	1,431	1,981	2,084	2,112	1,973	1,957	1,957	**1,728**
4.11	Network Integration (Base Charge)	cp	5,059	5,126	6,155	6,376	6,365	5,164	4,671	4,273	4,092	4,500	4,606	4,216	**5,050**
4.12	Subtotal Network		26,380	26,360	27,356	27,391	27,380	26,179	26,235	25,941	25,788	25,947	26,037	25,680	**26,390**
4.13	Average FY 2002 and FY 2003 Network		25,934	25,908	26,898	27,032	27,017	25,961	25,750	25,456	25,304	25,505	25,523	25,170	**25,955**
4.14	Network Integration (Load Shaping) FY 2002	cp	5,538	5,666	6,663	6,846	6,906	5,617	5,007	4,731	4,544	4,745	4,896	4,574	**5,478**
4.15	Network Integration (Load Shaping) FY 2003	cp	5,602	5,740	6,750	6,929	6,998	5,690	5,073	4,796	4,606	4,812	4,960	4,631	**5,549**
	Southern Intertie														
	FY 2002														
4.16	Intertie South (IS), North to South	m_cd	129	129	96	96	96	96	96	96	96	96	96	129	**104**
4.17	Intertie South (IS), South to North	m_cd	271	271	271	271	271	271	271	271	271	271	271	271	**271**
4.18	Point to Point Service	a_cd	2,641	2,641	2,641	2,641	2,641	2,641	3,036	3,752	3,852	3,852	3,852	2,637	**3,069**
4.19	Point to Point Service 2/	m_cd	405	317	317	317	317	317	317	420	448	462	462	462	**380**
4.20	Subtotal Southern Intertie		3,446	3,358	3,325	3,325	3,325	3,325	3,720	4,539	4,667	4,681	4,681	3,499	**3,824**
	FY 2003														
4.21	Intertie South (IS), North to South	m_cd	129	129	96	96	96	96	96	96	96	96	96	129	**104**
4.22	Intertie South (IS), South to North	m_cd	271	271	271	271	271	271	271	271	271	271	271	271	**271**
4.23	Point to Point Service	a_cd	2,637	2,637	2,637	2,437	2,437	2,437	2,437	2,836	2,836	2,781	2,781	2,381	**2,606**
4.24	Point to Point Service 2/	m_cd	419	331	331	331	331	331	331	434	462	498	498	498	**400**
4.25	Subtotal Southern Intertie		3,456	3,368	3,335	3,135	3,135	3,135	3,135	3,637	3,665	3,646	3,646	3,279	**3,381**
4.26	Average FY 2002 and FY 2003 Southern Intertie		3,451	3,363	3,330	3,230	3,230	3,230	3,428	4,088	4,166	4,164	4,164	3,389	**3,603**

1/ Annual contract demand (a_cd), monthly contract demand (m_cd), or coincidental peak (cp) which denotes contribution to TBL transmission system peak load.

2/ Monthly demands from PBL grandfathered agreements.

Table 5
Short-Term Transmission Sales
(Megawatts)

	Short-term Product	Comment	Units	(A) Oct.	(B) Nov.	(C) Dec.	(D) Jan.	(E) Feb.	(F) Mar.	(G) Apr.	(H) May	(I) Jun.	(J) Jul.	(K) Aug.	(L) Sep.	(M) Annual Average
	Network															
	FY 2002															
5.1	Daily Block1 Produc	1st 5 Days of Reservation:	MW-mos.	282	195	280	962	501	550	394	382	494	589	410	294	**445**
5.2	Daily Block2 Produc	Reservations beyond 5th da	MW-mos.	603	696	1,282	3,317	1,981	2,299	1,945	1,991	2,134	2,381	2,224	1,197	**1,837**
5.3	Hourly		aMW	367	380	648	1,776	1,123	1,182	998	985	1,121	1,232	1,093	636	**962**
5.4																**3,244**
	FY 2003															
5.5	Daily Block1 Produc	1st 5 Days of Reservation:	MW-mos.	290	202	288	1,004	527	573	382	369	477	575	391	277	**446**
5.6	Daily Block2 Produc	Reservations beyond 5th da	MW-mos.	621	720	1,318	3,459	2,082	2,398	1,883	1,922	2,060	2,325	2,116	1,127	**1,836**
5.7	Hourly		aMW	378	393	667	1,852	1,180	1,233	967	951	1,083	1,204	1,040	599	**962**
5.8																**3,245**
	Average FY2002/2003															
5.9	Daily Block1 Produc	1st 5 Days of Reservation:	MW-mos.	286	199	284	983	514	562	388	375	485	582	401	286	**445**
5.10	Daily Block2 Produc	Reservations beyond 5th da	MW-mos.	612	708	1,300	3,388	2,032	2,349	1,914	1,957	2,097	2,353	2,170	1,162	**1,837**
5.11	Hourly		aMW	373	387	657	1,814	1,151	1,208	982	968	1,102	1,218	1,067	618	**962**
5.12																**3,244**
	Southern Intertie															
	FY 2002															
5.13	Daily Block1 Produc	1st 5 Days of Reservation:	MW-mos.	103	72	62	281	26	92	173	39	93	393	233	141	**142**
5.14	Daily Block2 Produc	Reservations beyond 5th da	MW-mos.	253	166	214	840	412	576	1,206	1,241	1,270	1,719	1,819	755	**873**
5.15	Hourly		aMW	64	43	49	201	84	119	252	229	249	378	367	164	**183**
5.16																**1,198**
	FY 2003															
5.17	Daily Block1 Product	1st 5 Days of Reservations	MW-mos.	102	71	62	318	28	98	201	48	117	490	284	150	**164**
5.18	Daily Block2 Product	Reservations beyond 5th day	MW-mos.	251	165	212	950	434	613	1,408	1,539	1,608	2,141	2,223	806	**1,029**
5.19	Hourly		aMW	63	43	49	227	88	127	294	284	315	471	448	175	**215**
5.20																**1,409**
	Average FY2002/2003															
5.21	Daily Block1 Produc	1st 5 Days of Reservation:	MW-mos.	103	72	62	300	27	95	187	43	105	442	259	145	**153**
5.22	Daily Block2 Produc	Reservations beyond 5th da	MW-mos.	252	165	213	895	423	594	1,307	1,390	1,439	1,930	2,021	781	**951**
5.23	Hourly		aMW	63	43	49	214	86	123	273	256	282	424	408	169	**199**
5.24																**1,303**

Table 6
FPT Rate

			(A) Source	(B) 2002 Rates 1/
I. FPT Rate				
6. 1	M-G Distance	($/kW-mi-yr)		0.0503
6. 2	M-G Miscellaneous Facilities	($/kW-yr)		2.87
6. 3	M-G Terminal	($/kW-yr)		0.58
6. 4	M-G Interconnection Terminal	($/kW-yr)		0.52
6. 5	S-S Transformation	($/kW-yr)		5.41
6. 6	S-S Interconnection Terminal	($/kW-yr)		1.48
6. 7	S-S Intermediate Terminal	($/kW-yr)		2.09
6. 8	S-S Distance	($/kW-mi-yr)		0.4947
II. FPT Revenue Proration				
	Sales (MW)			
6. 9	Network		Tables 4.13(M)+5.12(M)	29,199
6.10	Southern Intertie		Tables 4.26(M)+5.24(M)	4,906
6.11	Total Sales		6.9 + 6.10	34,105
	Costs ($000)			
6.12	Scheduling Control & Dispatch		Table 7.1(A)+7.1(C)	68,557
6.13	Generation Reactive		Table 7.2(A)+7.2(C)	26,642
6.14	Network Rate Development Costs		Table 3.17(B)	387,074
6.15	Network-related Scheduling Control & Dispatch		6.12 * 6.9/6.11	58,695
6.16	Network-related Generation Reactive		6.13 * 6.9/6.11	22,809
6.17	Total Network Costs		6.14+6.15+6.16	468,578
6.18	**FPT Revenue ($000)**		Appendix F	38,017
	FPT Revenue Associated with:			
6.19	Network Transmission		6.18 * 6.14/6.17	31,404
6.20	Scheduling Control & Dispatch		6.18 * 6.15/6.17	4,762
6.21	Generation Reactive		6.18 * 6.16/6.17	1,851
6.22	Total FPT Revenues		6.19+6.20+6.21	38,017

1/ 2002 FPT rate equals 1996 FPT rate times 1.243.

Table 7
Ancillary Service Rates

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					FPT			RATES 2/				
		Avg RRQ 6/	Revenue Credits 1/		Credits 4/	Adj RRQ	Sales	Annual	Monthly	Daily 1	Daily 2	Hourly
		($000)	Alloc. %	($000)	($000)	($000)	(MW-Yr)	($/kW-yr)	($/kW-mo)	($/kW-day)	($/kW-day)	(mills/kWh)
	Ancillary Service Costs / Rates											
7. 1	Scheduling Control & Dispatch	72,688	77%	-4,131	-4,762	63,795	32,473	1.96	0.164	0.008	0.005	0.47
7. 2	Generation Reactive	26,814	3%	-172	-1,851	24,791	31,348	0.79	0.066	0.003	0.002	0.19

	Transmission Sales (Rate Design MW)	(MW)	Source
7. 3	Network (excluding FPT, no SDD) 5/	27,287	Tables 4(M) and 5(M)
7. 4	Southern Intertie 5/	5,186	Tables 4(M) and 5(M)
7. 5	Total Sales	32,473	7. 3 + 7. 4
7. 6	Less Gen Reactive Self Supply 3/	-1,125	
7. 7	Net Sales	31,348	7. 5 + 7. 6

1/ Revenue Credits and Eastern Intertie Adjustment from Table 3. Allocation based on distribution of fiber investment from Segmentation Study (TR-02-FS-BPA-02), Documentation Chapter 8.

2/ Daily 1 (day 1-5) equals annual rate /(365*5/7), Daily 2 (day 6 and beyond) equals annual rate /365.
Hourly is annual rate / ((8.760/168)*5*16).

3/ Estimated 4500MW of nonfederal generation which is directly connected to the FCRTS, and is west of the Cascades or near the head of the Southern Intertie. Of this, assumed 50% would be eligible to self supply generation reactive. Of those eligible, assumed a 50% reduction in billing demand.

4/ Table 6.20(B) and 6.21(B).

5/ Short term sales from table 5 are adjusted by 7/5 for Daily Block 1 Sales, and by 168/(5*16) for Hourly Sales.
Table 4 IR and PTP sales are discounted for Short Distance Discount by 256 MW.

6/ Revenue Requirement for Ancillary Services from Revenue Requirement Study, TR-02-FS-BPA-01.

Table 8
PTP, NT and IS Rates

		(A)	(B)	(C)	(D)
		Long Term Service	Short Term Service 1/		
		Monthly	Daily 1	Daily 2	Hourly
		($/kW-mo)	($/kW-day)	($/kW-day)	(mills/kWh)
	PTP				
8. 1	Settlement Agreement Cap	1.243	0.057	0.041	3.58
8. 2	Scheduling, Control & Dispatch	(0.164)	(0.008)	(0.005)	(0.47)
8. 3	Generation Reactive	(0.066)	(0.003)	(0.002)	(0.19)
8. 4	PTP	1.013	0.046	0.034	2.92
	NT				
8. 5	Settlement Agreement Cap	1.647			
8. 6	Scheduling, Control & Dispatch	(0.164)			
8. 7	Generation Reactive	(0.066)			
8. 8	Base Rate	(1.013)			
8. 9	Load Shaping	0.404			
	IS				
8. 10	Settlement Agreement Cap	1.389	0.064	0.046	4.00
8. 11	Scheduling, Control & Dispatch	(0.164)	(0.008)	(0.005)	(0.47)
8. 12	Generation Reactive	(0.066)	(0.003)	(0.002)	(0.19)
8. 13	IS	1.159	0.053	0.039	3.34

1/ Daily 1 = Monthly * 12/365 * 7/5
Daily 2 = Monthly * 12/365
Hourly = Monthly * 12 / [(8.76/168)*5*16]

Table 9
Montana Intertie Rate

		(A) Source	(B) Units	(C) Amount
	Montana Intertie (IM) Rate Calculation			
9. 1	TBL's Payments in the Calculation of TGT	81BP-90210 Exhibit D, Rev. D, 1998	($000/yr)	2,751
9. 2	TBL Montana Intertie Share	same	(MW-yr)	185
9. 3	IM-02 Annual Unit Cost	9.1 / 9.2	($/kW-yr)	14.87
9. 4	IM-02 Monthly Demand Charge	annual / 12	($/kW-mo)	**1.239**
9. 5	IM-02 Daily Block1 Demand Charge	annual / (365*5/7)	($/kW-day)	**0.057**
9. 6	IM-02 Daily Block2 Demand Charge	annual / 365	($/kW-day)	**0.041**
9. 7	IM-02 Hourly Rate	annual /[(8.760/168) * 5 * 16]	(mills/kWh)	**3.56**

Table 10
Summary of Transmission and Ancillary Services Rates

		Units	(A) 1996 Rates	(B) 2002 Rates	(C) Percent Change (B) / (A)
	FPT-02.1 and FPT-02.3 Formula Power Transmission				
10. 1	M-G Distance	($/kW-mi-yr)	0.0405	0.0503	24.2%
10. 2	M-G Miscellaneous Facilities	($/kW-yr)	2.31	2.87	24.2%
10. 3	M-G Terminal	($/kW-yr)	0.47	0.58	23.4%
10. 4	M-G Interconnection Terminal	($/kW-yr)	0.42	0.52	23.8%
10. 5	S-S Transformation	($/kW-yr)	4.35	5.41	24.4%
10. 6	S-S Interconnection Terminal	($/kW-yr)	1.19	1.48	24.4%
10. 7	S-S Intermediate Terminal	($/kW-yr)	1.68	2.09	24.4%
10. 8	S-S Distance	($/kW-mi-yr)	0.3980	0.4947	24.3%
10. 9	Overall FPT Rate	($/kW-yr)	8.99	11.18	24.3%
10.10	Overall FPT Rate	($/kW-mo)	0.749	0.932	24.3%
	IR-02 Integration of Resources				
10.11	Demand	($/kW-mo)	1.000	1.243	24.3%
	NT-02 Network Integration				
10.12	Base Rate ($/kW-mo)	($/kW-mo)	1.000	1.013	1.3%
10.10	Load Shaping ($/kW-mo)	($/kW-mo)	0.539	0.404	-25.0%
10.14	Base plus Load Shaping	($/kW-mo)	1.539	1.417	-7.9%
	PTP-02 Point-to-Point				
10.15	Demand	($/kW-mo)	1.000	1.013	1.3%
10.16	Daily Block 1 (day 1 thru 5)	($/kW-day)	0.046	0.046	0.0%
10.17	Daily Block 2 (day 6 and beyond)	($/kW-day)	0.033	0.034	3.0%
10.18	Hourly	(mills/kWh)	2.52	2.92	15.9%
	Unauthorized Increase Charge				
10.19	Demand	($/kW-mo)	12.000	4.052	-66.2%
	Utility Delivery				
10.20	Demand	($/kW-mo)	0.750	0.932	24.3%
	IS-02 Southern Intertie				
10.21	Demand	($/kW-mo)	1.274	1.159	-9.0%
10.22	Daily Block 1 (day 1 thru 5)	($/kW-day)	0.059	0.053	-9.9%
10.23	Daily Block 2 (day 6 and beyond)	($/kW-day)	0.042	0.039	-7.1%
10.24	Hourly	(mills/kWh)	2.54	3.34	31.5%
	IM-02 Montana Intertie				
10.25	Demand	($/kW-mo)	1.234	1.239	0.4%
10.26	Daily Block 1 (day 1 thru 5)	($/kW-day)	0.057	0.057	0.0%
10.27	Daily Block 2 (day 6 and beyond)	($/kW-day)	0.041	0.041	0.0%
10.28	Hourly	(mills/kWh)	3.56	3.56	0.0%
	Eastern Intertie				
10.29	IE-02	(mills/kWh)	1.68	1.38	-17.9%

Table 10
Summary of Transmission and Ancillary Services Rates

		Units	(A) 1996 Rates	(B) 2002 Rates	(C) Percent Change (B) / (A)
	Power Factor Penalty Charge				
10.30	Demand -- Lagging	($/kVAr-mo)	0.08	0.28	250.0%
10.31	Demand -- Leading	($/kVAr-mo)	0.06	0.24	300.0%
10.32	Energy -- Lagging or Leading	($/kVAr-hour)	0.53	n.a.	
	Scheduling, System Control and Dispatch				
10.33	Demand	($/kW-mo)	n.a.	0.164	n.a.
10.34	Daily Block 1 (day 1 thru 5)	($/kW-day)	n.a.	0.008	n.a.
10.35	Daily Block 2 (day 6 and beyond)	($/kW-day)	n.a.	0.005	n.a.
10.36	Hourly	(mills/kWh)	n.a.	0.47	n.a.
	Reactive Supply and Voltage Control from Generation Sources				
10.37	Demand	($/kW-mo)	n.a.	0.066	n.a.
10.38	Daily Block 1 (day 1 thru 5)	($/kW-day)	n.a.	0.003	n.a.
10.39	Daily Block 2 (day 6 and beyond)	($/kW-day)	n.a.	0.002	n.a.
10.40	Hourly	(mills/kWh)	n.a.	0.19	n.a.
	Regulation and Frequency Response				
10.41	Hourly	(mills/kWh)	n.a.	0.30	n.a.
	Energy Imbalance				
10.42	Hourly	(mills/kWh)	n.a.	100.00	n.a.
	Operating Reserves				
10.43	Spinning	(mills/kWh)	n.a.	8.27	n.a.
10.44	Supplemental	(mills/kWh)	n.a.	8.27	n.a.

Table 11
Transmission Revenue Summary
($000)

	Service	Rate Schedule	(A) FY 2002	(B) FY 2003	(C) 2-Yr Total
	General Transmission				
1	Formula Power Transmission	FPT-02	38,017	38,017	76,033
2	Integration of Resources	IR-02	68,315	68,315	136,630
3	Network Transmission, Base	NT-02	60,421	61,392	121,813
4	Network Transmission, Load Shaping	NT-02	26,556	26,901	53,457
5	Point to Point, Long-term Contracts	PTP-02	152,657	162,253	314,911
6	Point to Point, Daily Block 1	PTP-02	7,474	7,502	14,976
7	Point to Point, Daily Block 2	PTP-02	22,834	22,813	45,647
8	Point to Point, Hourly	PTP-02	24,620	24,624	49,244
9	**Subtotal General Rates, Network**		**400,894**	**411,817**	**812,711**
10	Southern Intertie, Long-term Contracts	IS-02	53,188	47,023	100,211
11	Southern Intertie, Daily Block 1	IS-02	2,775	3,203	5,978
12	Southern Intertie, Daily Block 2	IS-02	12,479	14,725	27,204
13	Southern Intertie, Hourly	IS-02	5,385	6,333	11,717
14	**Subtotal General Rates, Southern Intertie**		**73,826**	**71,284**	**145,110**
15	Montana Intertie	IM-02	**0**	**0**	**0**
16	Intertie East	IE-02	**0**	**0**	**0**
17	Utility Delivery Charge	Delv	**9,161**	**9,268**	**18,429**
18	DSI Delivery Charge	Delv	**5,790**	**5,790**	**11,581**
19	**Subtotal General Transmission Rates**		**489,672**	**498,159**	**987,831**
	Other				
20	Annual Cost Rate		1,375	1,375	2,751
21	Columbia Storage Power Exchange		268	127	395
22	Fiber		15,500	17,500	33,000
23	Fiber Depreciation		696	696	1,392
24	Generation Integration		7,369	7,235	14,603
25	Irrigation Pumping Power		1,288	1,288	2,577
26	Nonfederal Participation Depreciation		3,335	3,335	6,670
27	Operations and Maintenance		675	675	1,350
28	Personal Communications Wireless		4,070	4,430	8,500
29	Power Factor Penalty Charge		5,000	5,000	10,000
30	Remedial Action Scheme		597	597	1,194
31	Reservation Fee		828	1,656	2,483
32	Supplemental Capacity Wheeling		62	27	89
33	Townsend Garrison Transmission		10,136	10,136	20,271
34	Use of Facilities		5,679	5,679	11,358
35	**Subtotal Other Transmission**		**56,877**	**59,755**	**116,633**
	Ancillary				
36	Scheduling Control & Dispatch		53,609	55,062	108,671
37	Generation Reactive		20,633	21,257	41,890
38	Regulation & Frequency Response		16,038	15,663	31,701
39	Energy Imbalance		0	0	0
40	Operating Reserves - Spinning		18,996	17,903	36,899
41	Operating Reserves - Supplemental		18,996	17,889	36,885
42	**Subtotal Ancillary Services**		**128,273**	**127,773**	**256,046**
43	**Total Revenue**		**674,822**	**685,687**	**1,360,509**
44	**Total TBL Table 1 Costs**		**671,048**	**679,237**	**1,350,285**
45	**Revenue Longfall (Shortfall)**		**3,774**	**6,450**	**10,224**

APPENDICES

APPENDIX A

Long-Term Transmission Demands

Appendix A
Long-term Transmission Demands, FY2002
(Megawatts)

FY 2002

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1	COWLITZ COUNTY PUD NO 1	FPT.1	MS79-86BP92043	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.1
2	COWLITZ COUNTY PUD NO 1	FPT.1	EW78-Y-83-00025	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
3	DOUGLAS COUNTY PUD NO 1	FPT.1	MS79-88BP92389	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
4	DOUGLAS COUNTY PUD NO 1	FPT.1	MS79-80BP90066	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8
5	PACIFIC POWER & LIGHT COM	FPT.1	14-03-26811	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0
6	PACIFIC POWER & LIGHT COM	FPT.1	MS79-79BP90100	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	234.9
7	PACIFIC POWER & LIGHT COM	FPT.1	MS79-81BP90168	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
8	PACIFIC POWER & LIGHT COM	FPT.1	MS79-86BP92269	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.1
9	PACIFIC POWER & LIGHT COM	FPT.1	MS79-87BP92325	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
10	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.1
11	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94316	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0
12	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94333	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
13	PEND OREILLE COUNTY PUD N	FPT.1	MS79-90BP92488	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.1
14	PORTLAND GENERAL ELECTRIC	FPT.1	MS79-85BP92187	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
15	PORTLAND GENERAL ELECTRIC	FPT.1	MS79-86BP92260	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	74.9
16	POWER RESOURCES GROUP (ar	FPT.1	MS79-95BP94151	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.1
17	PUGET SOUND ENERGY, INC.	FPT.1	MS79-85BP92185	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
18	TACOMA PUBLIC UTILITIES	FPT.1	MS79-94BP93936	74.0	74.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	74.0	49.3
19	WASHINGTON WATER POWER (A	FPT.1	MS79-85BP92186	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
20	WASHINGTON WATER POWER (A	FPT.1	DE-MS79-86BP91970	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
21	COWLITZ COUNTY PUD NO 1	FPT.3	14-03-001-13520	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
22	PACIFIC POWER & LIGHT COM	FPT.3	14-03-09228	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.1
23	PACIFIC POWER & LIGHT COM	FPT.3	14-03-14612	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
24	TACOMA PUBLIC UTILITIES	FPT.3	14-03-13512	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
	TOTAL FPT			3,429.4	3,429.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,429.4	3,405.0
25	EUGENE WATER & ELECTRIC B	IR	MS79-86BP91651	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
26	EUGENE WATER & ELECTRIC B	IR	MS79-86BP91651	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6
27	FOREST GROVE, CITY OF	IR	MS79-86BP91652	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
28	KITTITAS COUNTY PUD NO 1	IR	MS79-86BP91845	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
29	KITTITAS COUNTY PUD NO 1	IR	MS79-86BP91845	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
30	MILTON-FREEWATER, CITY OF	IR	MS79-86BP91655	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
31	PORTLAND GENERAL ELECTRIC	IR	MS79-89BP92273	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0
32	PORTLAND GENERAL ELECTRIC	IR	MS79-89BP92273	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9
33	PUGET SOUND ENERGY, INC.	IR	MS79-94BP93947	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
34	PUGET SOUND ENERGY, INC.	IR	14-03-001-13439	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
35	PUGET SOUND ENERGY, INC.	IR	14-03-001-13574	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
36	PUGET SOUND ENERGY, INC.	IR	14-03-001-14502	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
37	PUGET SOUND ENERGY, INC.	IR	14-03-39361	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
38	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92427	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
39	PUGET SOUND ENERGY, INC.	IR	14-03-45241	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0
40	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92461	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
41	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92781	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	TOTAL IR			4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2
42	ALCOA/NORTHWEST ALLOYS,IN	PTP	00TX-NW_ALLOYS	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
43	ALCOA/NORTHWEST ALLOYS,IN	PTP	01TX-ALOCA_WENATCHEE	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
44	BONNEVILLE POWER BUSINESS	PTP	96MS-95363	1,482.0	1,482.0	1,482.0	1,478.0	1,478.0	1,478.0	1,478.0	1,478.0	1,478.0	1,478.0	1,478.0	1,478.0	1,479.0
45	BONNEVILLE POWER BUSINESS	PTP	96MS-96060	1,645.0	1,557.0	1,557.0	1,557.0	1,557.0	1,557.0	1,579.0	1,682.0	1,710.0	1,549.0	1,387.0	1,387.0	1,560.3
46	CLATSKANIE COUNTY PUD	PTP	97TX-10040_FollowOn	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
47	COLUMBIA FALLS ALUMINUM C	PTP	98TX-10139	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0
48	DOUGLAS COUNTY PUD NO 1	PTP	00TX-xxPBL	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
49	ELF ATOCHEM NORTH AMERICA	PTP	01TX-ELFATOCHEM@RC	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0

Appendix A
Long-term Transmission Demands, FY2002
(Megawatts)

FY 2002

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
50	EMERALD PUD	PTP	01TX-EPUD_AE_INPUT	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
51	ENGAGE ENERGY	PTP	98TX-10158	0.0	0.0	0.0	0.0	0.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	157.5
52	EUGENE WATER & ELECTRIC B	PTP	01TX-EWEB_AE_INPUT	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
53	GOLDENDALE (COLUMBIA ALUM	PTP	96MS-96109	326.0	326.0	326.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	335.0	332.7
54	GRANT COUNTY PUD NO 2	PTP	00TX-xxPRWAN	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
55	GRAYS HARBOR COUNTY PUD N	PTP	96MS-96083	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0
56	GRAYS HARBOR COUNTY PUD N	PTP	96MS-96083	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9
57	HERMISTON POWER PARTNERSH	PTP	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
58	IDAHO FALLS, CITY OF	PTP	96MS-96105	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
59	IDAHO POWER COMPANY	PTP	96MS-96108	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
60	IDAHO POWER COMPANY	PTP	96MS-96108	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1
61	INTALCO ALUMINUM CORPORAT	PTP	00TX-INTALCO	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0
62	KAISER ALUMINUM COMPANY	PTP	97TX-96107	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
63	KAISER ALUMINUM COMPANY	PTP	97TX-96107DS	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0
64	KLICKITAT COUNTY PUD NO 1	PTP	97TX-10038	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1
65	NORTHWEST ALUMINUM COMPAN	PTP	96MS-96111	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
66	OREGON METALLURGICAL CORP	PTP	01TX-ORMET@RC	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
67	PACIFIC POWER & LIGHT COM	PTP	96MS-96035	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
68	PACIFIC POWER & LIGHT COM	PTP	96MS-96035	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9
69	PACIFIC POWER & LIGHT COM	PTP	00TX-PPLGSN	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
70	PEND OREILLE COUNTY PUD N	PTP	97TX-10090	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
71	PEND OREILLE COUNTY PUD N	PTP	97TX-10090	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4
72	PORTLAND GENERAL ELECTRIC	PTP	98TX-10174	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
73	POWEREX: BC HYDRO EXPORT	PTP	97TX-96084	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
74	POWEREX: BC HYDRO EXPORT	PTP	99TX-10251	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
75	REYNOLDS METALS COMPANY	PTP	01TX-REYNOLDS@RC	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0
76	SEATTLE, CITY OF	PTP	96MS-96018	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0
77	SNOHOMISH COUNTY PUD NO 1	PTP	96MS-96092	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0
78	SPRINGFIELD, CITY OF, UTI	PTP	97TX-96038	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
79	SPRINGFIELD, CITY OF, UTI	PTP	97TX-96038	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6
80	TACOMA PUBLIC UTILITIES	PTP	98TX-10103	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
81	TACOMA PUBLIC UTILITIES	PTP	01TX-TCL_GGILBERT	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0	410.0
82	VANALCO, INC	PTP	00TX-VANALCO	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
83	WASHINGTON WATER POWER (A	PTP	96MS-96008	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0
84	WASHINGTON WATER POWER (A	PTP	97TX-50002	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0
	TOTAL PTP			12,526.2	12,438.2	12,438.2	12,443.2	12,443.2	12,713.2	12,735.2	12,838.2	12,866.2	12,705.2	12,543.2	12,543.2	12,602.7
85	BONNEVILLE POWER BUSINESS	IS	96MS-95363	1,610.0	1,610.0	1,610.0	1,610.0	1,610.0	1,610.0	2,005.0	2,005.0	2,005.0	2,005.0	2,005.0	1,605.0	1,774.2
86	BONNEVILLE POWER BUSINESS	IS	96MS-96060	405.0	317.0	317.0	317.0	317.0	317.0	317.0	420.0	448.0	462.0	462.0	462.0	380.1
87	HERMISTON POWER PARTNERSH	IS	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
88	IDAHO POWER COMPANY	IS	91BP-93094	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
89	KLAMATH FALLS, CITY OF	IS	99TX-KFALLS_GENPROJ	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
90	PACIFIC POWER & LIGHT COM	IS	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
91	PACIFIC POWER & LIGHT COM	IS	MS79-94BP94285	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
92	POWEREX: BC HYDRO EXPORT	IS	99TX-10251	105.0	105.0	105.0	105.0	105.0	105.0	105.0	521.0	521.0	521.0	521.0	105.0	243.6
93	POWEREX: BC HYDRO EXPORT	IS	99TX-10230	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	400.0	400.0	400.0	1.0	125.1
94	TACOMA PUBLIC UTILITIES	IS	MS79-94BP92490	33.0	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.0	8.3
95	TRANSALTA ENERGY MARKETIN	IS	98TX-10172	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
	TOTAL IS			3,446.0	3,358.0	3,325.0	3,325.0	3,325.0	3,325.0	3,720.0	4,539.0	4,667.0	4,681.0	4,681.0	3,499.0	3,824.3

Appendix A
Long-term Transmission Demands, FY2003
(Megawatts)

FY 2003

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
96	COWLITZ COUNTY PUD NO 1	FPT.1	MS79-86BP92043	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.1
97	COWLITZ COUNTY PUD NO 1	FPT.1	EW78-Y-83-00025	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
98	DOUGLAS COUNTY PUD NO 1	FPT.1	MS79-88BP92389	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
99	DOUGLAS COUNTY PUD NO 1	FPT.1	MS79-80BP90066	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8
100	PACIFIC POWER & LIGHT COM	FPT.1	14-03-26811	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0
101	PACIFIC POWER & LIGHT COM	FPT.1	MS79-79BP90100	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	234.9
102	PACIFIC POWER & LIGHT COM	FPT.1	MS79-81BP90168	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
103	PACIFIC POWER & LIGHT COM	FPT.1	MS79-86BP92269	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.1
104	PACIFIC POWER & LIGHT COM	FPT.1	MS79-87BP92325	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
105	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.1
106	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94316	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0
107	PACIFIC POWER & LIGHT COM	FPT.1	MS79-94BP94333	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
108	PEND OREILLE COUNTY PUD N	FPT.1	MS79-90BP92488	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.1
109	PORTLAND GENERAL ELECTRIC	FPT.1	MS79-85BP92187	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
110	PORTLAND GENERAL ELECTRIC	FPT.1	MS79-86BP92260	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	74.9
111	POWER RESOURCES GROUP (ar	FPT.1	MS79-95BP94151	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.1
112	PUGET SOUND ENERGY, INC.	FPT.1	MS79-85BP92185	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
113	TACOMA PUBLIC UTILITIES	FPT.1	MS79-94BP93936	74.0	74.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	74.0	49.3
114	WASHINGTON WATER POWER (A	FPT.1	MS79-85BP92186	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
115	WASHINGTON WATER POWER (A	FPT.1	DE-MS79-86BP91970	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
116	COWLITZ COUNTY PUD NO 1	FPT.3	14-03-001-13520	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
117	PACIFIC POWER & LIGHT COM	FPT.3	14-03-09228	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.1
118	PACIFIC POWER & LIGHT COM	FPT.3	14-03-14612	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
119	TACOMA PUBLIC UTILITIES	FPT.3	14-03-13512	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
	TOTAL FPT			3,429.4	3,429.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,396.4	3,429.4	3,405.0
120	EUGENE WATER & ELECTRIC B	IR	MS79-86BP91651	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
121	EUGENE WATER & ELECTRIC B	IR	MS79-86BP91651	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6	-19.6
122	FOREST GROVE, CITY OF	IR	MS79-86BP91652	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
123	KITTITAS COUNTY PUD NO 1	IR	MS79-86BP91845	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
124	KITTITAS COUNTY PUD NO 1	IR	MS79-86BP91845	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
125	MILTON-FREEWATER, CITY OF	IR	MS79-86BP91655	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
126	PORTLAND GENERAL ELECTRIC	IR	MS79-89BP92273	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0	2,243.0
127	PORTLAND GENERAL ELECTRIC	IR	MS79-89BP92273	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9	-183.9
128	PUGET SOUND ENERGY, INC.	IR	MS79-94BP93947	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0	1,157.0
129	PUGET SOUND ENERGY, INC.	IR	14-03-001-13439	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
130	PUGET SOUND ENERGY, INC.	IR	14-03-001-13574	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
131	PUGET SOUND ENERGY, INC.	IR	14-03-001-14502	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
132	PUGET SOUND ENERGY, INC.	IR	14-03-39361	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
133	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92427	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
134	PUGET SOUND ENERGY, INC.	IR	14-03-45241	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0
135	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92461	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
136	PUGET SOUND ENERGY, INC.	IR	MS79-92BP92781	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	TOTAL IR			4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2	4,542.2
137	ALCOA/NORTHWEST ALLOYS,IN	PTP	00TX-NW_ALLOYS	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
138	ALCOA/NORTHWEST ALLOYS,IN	PTP	01TX-ALOCA_WENATCHEE	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
139	BONNEVILLE POWER BUSINESS	PTP	96MS-95363	1,478.0	1,478.0	1,478.0	1,278.0	1,278.0	1,278.0	1,278.0	1,278.0	1,278.0	1,168.0	1,168.0	1,168.0	1,300.5
140	BONNEVILLE POWER BUSINESS	PTP	96MS-96060	1,519.0	1,431.0	1,431.0	1,431.0	1,431.0	1,431.0	1,981.0	2,084.0	2,112.0	1,973.0	1,957.0	1,957.0	1,728.1
141	CLATSKANIE COUNTY PUD	PTP	97TX-10040_FollowOn	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
142	COLUMBIA FALLS ALUMINUM C	PTP	98TX-10139	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0
143	DOUGLAS COUNTY PUD NO 1	PTP	00TX-xxPBL	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
144	ELF ATOCHEM NORTH AMERICA	PTP	01TX-ELFATOCHEM@RC	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
145	EMERALD PUD	PTP	01TX-EPUD_AE_INPUT	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0

Appendix A
Long-term Transmission Demands, FY2003
(Megawatts)

FY 2003

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
146	ENGAGE ENERGY	PTP	98TX-10158	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
147	EUGENE WATER & ELECTRIC B	PTP	01TX-EWEB_AE_INPUT	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
148	GOLDENDALE (COLUMBIA ALUM	PTP	96MS-96109	335.0	335.0	335.0	349.0	349.0	349.0	349.0	349.0	349.0	349.0	349.0	349.0	345.5
149	GRANT COUNTY PUD NO 2	PTP	00TX-xxPRWAN	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
150	GRAYS HARBOR COUNTY PUD N	PTP	96MS-96083	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0	212.0
151	GRAYS HARBOR COUNTY PUD N	PTP	96MS-96083	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9
152	HERMISTON POWER PARTNERSH	PTP	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
153	IDAHO FALLS, CITY OF	PTP	96MS-96105	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
154	IDAHO POWER COMPANY	PTP	96MS-96108	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
155	IDAHO POWER COMPANY	PTP	96MS-96108	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1
156	INTALCO ALUMINUM CORPORAT	PTP	00TX-INTALCO	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0
157	KAISER ALUMINUM COMPANY	PTP	97TX-96107	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
158	KAISER ALUMINUM COMPANY	PTP	97TX-96107DS	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0	345.0
159	KLICKITAT COUNTY PUD NO 1	PTP	97TX-10038	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1	76.1
160	NATIONAL ENERGY SYSTEMS C	PTP	00TX-SE2@RC	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0	660.0
161	NORTHWEST ALUMINUM COMPAN	PTP	96MS-96111	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
162	OREGON METALLURGICAL CORP	PTP	01TX-ORMET@RC	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
163	PACIFIC POWER & LIGHT COM	PTP	96MS-96035	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
164	PACIFIC POWER & LIGHT COM	PTP	96MS-96035	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9	-10.9
165	PACIFIC POWER & LIGHT COM	PTP	00TX-PPLGSN	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
166	PEND OREILLE COUNTY PUD N	PTP	97TX-10090	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
167	PEND OREILLE COUNTY PUD N	PTP	97TX-10090	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4	-2.4
168	PORTLAND GENERAL ELECTRIC	PTP	98TX-10174	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
169	POWEREX: BC HYDRO EXPORT	PTP	97TX-96084	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
170	POWEREX: BC HYDRO EXPORT	PTP	99TX-10251	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
171	REYNOLDS METALS COMPANY	PTP	01TX-REYNOLDS@RC	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0
172	SEATTLE, CITY OF	PTP	96MS-96018	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0
173	SNOHOMISH COUNTY PUD NO 1	PTP	96MS-96092	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0
174	SPRINGFIELD, CITY OF, UTI	PTP	97TX-96038	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
175	SPRINGFIELD, CITY OF, UTI	PTP	97TX-96038	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6
176	TACOMA PUBLIC UTILITIES	PTP	98TX-10103	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
177	TACOMA PUBLIC UTILITIES	PTP	01TX-TCL_GGILBERT	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0	425.0
178	VANALCO, INC	PTP	00TX-VANALCO	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
179	WASHINGTON WATER POWER (A	PTP	96MS-96008	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0
180	WASHINGTON WATER POWER (A	PTP	97TX-50002	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0
	TOTAL PTP			13,350.2	13,262.2	13,262.2	13,076.2	13,076.2	13,076.2	13,626.2	13,729.2	13,757.2	13,508.2	13,492.2	13,492.2	13,392.3
181	BONNEVILLE POWER BUSINESS	IS	96MS-95363	1,605.0	1,605.0	1,605.0	1,405.0	1,405.0	1,405.0	1,405.0	1,405.0	1,405.0	1,350.0	1,350.0	1,350.0	1,441.3
182	BONNEVILLE POWER BUSINESS	IS	96MS-96060	419.0	331.0	331.0	331.0	331.0	331.0	331.0	434.0	462.0	498.0	498.0	498.0	399.6
183	HERMISTON POWER PARTNERSH	IS	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
184	IDAHO POWER COMPANY	IS	91BP-93094	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
185	KLAMATH FALLS, CITY OF	IS	99TX-KFALLS_GENPROJ	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
186	PACIFIC POWER & LIGHT COM	IS	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
187	PACIFIC POWER & LIGHT COM	IS	MS79-94BP94285	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
188	POWEREX: BC HYDRO EXPORT	IS	99TX-10251	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0
189	POWEREX: BC HYDRO EXPORT	IS	99TX-10230	1.0	1.0	1.0	1.0	1.0	1.0	1.0	400.0	400.0	400.0	400.0	0.0	133.9
190	TACOMA PUBLIC UTILITIES	IS	MS79-94BP92490	33.0	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.0	8.3
191	TRANSALTA ENERGY MARKETIN	IS	98TX-10172	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
	TOTAL IS			3,456.0	3,368.0	3,335.0	3,135.0	3,135.0	3,135.0	3,135.0	3,637.0	3,665.0	3,646.0	3,646.0	3,279.0	3,381.1

APPENDIX B

NT Base and Load Shaping Sales

Appendix B

NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1	ALBION, CITY OF	102		BASE	TBL load forecast	2002	0.51	0.61	0.70	0.77	0.78	0.62	0.49	0.39	0.28	0.32	0.26	0.29	0.50
2	ALBION, CITY OF	102		LS	TBL load forecast	2002	0.51	0.61	0.70	0.77	0.78	0.62	0.49	0.39	0.28	0.32	0.26	0.29	0.50
3	ALBION, CITY OF	102		BASE	TBL load forecast	2003	0.51	0.62	0.71	0.78	0.79	0.62	0.49	0.40	0.28	0.32	0.27	0.29	0.51
4	ALBION, CITY OF	102		LS	TBL load forecast	2003	0.51	0.62	0.71	0.78	0.79	0.62	0.49	0.40	0.28	0.32	0.27	0.29	0.51
5	ALDER MUTUAL LIGHT COMPAN	301		BASE	TBL load forecast	2002	0.64	0.71	0.83	0.76	0.81	0.68	0.54	0.40	0.30	0.28	0.29	0.30	0.55
6	ALDER MUTUAL LIGHT COMPAN	301		LS	TBL load forecast	2002	0.64	0.71	0.83	0.76	0.81	0.68	0.54	0.40	0.30	0.28	0.29	0.30	0.55
7	ALDER MUTUAL LIGHT COMPAN	301		BASE	TBL load forecast	2003	0.65	0.72	0.85	0.77	0.83	0.69	0.55	0.41	0.30	0.29	0.30	0.30	0.55
8	ALDER MUTUAL LIGHT COMPAN	301		LS	TBL load forecast	2003	0.65	0.72	0.85	0.77	0.83	0.69	0.55	0.41	0.30	0.29	0.30	0.30	0.55
9	ASHLAND, CITY OF	103		BASE	TBL load forecast	2002	21.79	24.09	27.61	32.57	31.86	28.82	25.76	21.75	20.72	25.07	27.45	22.17	25.81
10	ASHLAND, CITY OF	103		LS	TBL load forecast	2002	25.79	28.09	31.61	32.57	31.86	28.82	25.76	21.75	20.72	25.07	27.45	22.17	26.81
11	ASHLAND, CITY OF	103		BASE	TBL load forecast	2003	25.82	28.12	31.65	32.62	31.90	28.86	25.79	21.78	20.74	25.10	27.49	22.20	26.84
12	ASHLAND, CITY OF	103		LS	TBL load forecast	2003	25.82	28.12	31.65	32.62	31.90	28.86	25.79	21.78	20.74	25.10	27.49	22.20	26.84
13	ASOTIN COUNTY PUD	201		BASE	recent pwr bills	2002	0.08	0.09	0.00	0.00	0.00	0.00	0.08	0.10	0.43	0.75	1.36	1.41	0.36
14	ASOTIN COUNTY PUD	201		LS	recent pwr bills	2002	0.08	0.09	0.00	0.00	0.00	0.00	0.08	0.10	0.43	0.75	1.36	1.41	0.36
15	ASOTIN COUNTY PUD	201		BASE	recent pwr bills	2003	0.08	0.09	0.00	0.00	0.00	0.00	0.08	0.11	0.43	0.75	1.36	1.41	0.36
16	ASOTIN COUNTY PUD	201		LS	recent pwr bills	2003	0.08	0.09	0.00	0.00	0.00	0.00	0.08	0.11	0.43	0.75	1.36	1.41	0.36
17	BANDON, CITY OF	104		BASE	TBL load forecast	2002	9.87	10.49	11.38	12.42	13.49	12.31	11.18	8.43	6.51	6.74	6.26	6.56	9.64
18	BANDON, CITY OF	104		LS	TBL load forecast	2002	9.87	10.49	11.38	12.42	13.49	12.31	11.18	8.43	6.51	6.74	6.26	6.56	9.64
19	BANDON, CITY OF	104		BASE	TBL load forecast	2003	10.07	10.70	11.61	12.67	13.76	12.55	11.41	8.60	6.64	6.87	6.38	6.69	9.83
20	BANDON, CITY OF	104		LS	TBL load forecast	2003	10.07	10.70	11.61	12.67	13.76	12.55	11.41	8.60	6.64	6.87	6.38	6.69	9.83
21	BENTON COUNTY PUD NO 1	203		BASE	TBL load forecast	2002	220.61	214.24	272.23	310.49	300.03	223.04	209.68	210.39	253.01	305.89	332.18	229.23	256.75
22	BENTON COUNTY PUD NO 1	203		LS	TBL load forecast	2002	221.96	215.59	273.58	311.84	301.38	224.39	210.89	211.60	254.22	307.10	333.39	230.44	258.03
23	BENTON COUNTY PUD NO 1	203		BASE	TBL load forecast	2003	224.06	217.60	276.46	315.29	304.67	226.53	214.04	214.75	258.02	311.69	338.37	233.88	261.28
24	BENTON COUNTY PUD NO 1	203		LS	TBL load forecast	2003	225.27	218.81	277.67	316.50	305.88	227.74	214.04	214.75	258.02	311.69	338.37	233.88	261.89
25	BENTON RURAL ELECTRIC ASS	303		BASE	TBL load forecast	2002	68.64	54.98	70.21	71.16	75.96	53.82	49.52	54.97	66.01	79.41	94.00	77.88	68.05
26	BENTON RURAL ELECTRIC ASS	303		LS	TBL load forecast	2002	68.64	54.98	70.21	71.16	75.96	53.82	49.52	54.97	66.01	79.41	94.00	77.88	68.05
27	BENTON RURAL ELECTRIC ASS	303		BASE	TBL load forecast	2003	70.95	56.83	72.56	73.55	78.51	55.63	51.18	56.82	68.22	82.08	97.15	80.50	70.33
28	BENTON RURAL ELECTRIC ASS	303		LS	TBL load forecast	2003	70.95	56.83	72.56	73.55	78.51	55.63	51.18	56.82	68.22	82.08	97.15	80.50	70.33
29	BIG BEND ELECTRIC COOPERA	306		BASE	TBL load forecast	2002	51.80	33.60	37.40	40.20	38.30	30.40	51.40	77.80	106.50	93.70	99.20	81.60	61.83
30	BIG BEND ELECTRIC COOPERA	306		LS	TBL load forecast	2002	51.81	33.61	37.43	40.23	38.32	30.41	51.38	77.76	106.47	93.70	99.18	81.60	61.83
31	BIG BEND ELECTRIC COOPERA	306		BASE	TBL load forecast	2003	52.36	33.97	37.82	40.65	38.73	30.73	51.92	78.57	107.59	94.69	100.22	82.46	62.48
32	BIG BEND ELECTRIC COOPERA	306		LS	TBL load forecast	2003	52.36	33.97	37.82	40.65	38.73	30.73	51.92	78.57	107.59	94.69	100.22	82.46	62.48
33	BLACHLY-LANE COUNTY COOPE	309	PNGC	BASE	TBL load forecast	2002	27.37	24.99	30.99	30.33	33.92	27.62	26.41	22.19	19.30	19.79	18.80	18.69	25.03
34	BLACHLY-LANE COUNTY COOPE	309	PNGC	LS	TBL load forecast	2002	27.37	24.99	30.99	30.33	33.92	27.62	26.41	22.19	19.30	19.79	18.80	18.69	25.03
35	BLACHLY-LANE COUNTY COOPE	309	PNGC	BASE	TBL load forecast	2003	27.88	25.46	31.56	30.89	34.55	28.14	26.90	22.61	19.66	20.16	19.15	19.04	25.50
36	BLACHLY-LANE COUNTY COOPE	309	PNGC	LS	TBL load forecast	2003	27.88	25.46	31.56	30.89	34.55	28.14	26.90	22.61	19.66	20.16	19.15	19.04	25.50
37	BLAINE, CITY OF	106		BASE	TBL load forecast	2002	9.52	9.93	11.14	10.61	10.66	8.02	7.04	6.29	5.43	5.89	5.73	7.04	8.11
38	BLAINE, CITY OF	106		LS	TBL load forecast	2002	9.52	9.93	11.14	10.61	10.66	8.02	7.04	6.29	5.43	5.89	5.73	7.04	8.11
39	BLAINE, CITY OF	106		BASE	TBL load forecast	2003	9.57	9.98	11.19	10.66	10.71	8.06	7.08	6.32	5.46	5.92	5.76	7.08	8.15
40	BLAINE, CITY OF	106		LS	TBL load forecast	2003	9.57	9.98	11.19	10.66	10.71	8.06	7.08	6.32	5.46	5.92	5.76	7.08	8.15
41	BONNERS FERRY, CITY OF	107		BASE	TBL load forecast	2002	20.15	19.78	19.19	20.83	21.19	6.76	5.54	2.72	2.21	2.67	6.34	5.43	11.07
42	BONNERS FERRY, CITY OF	107		LS	TBL load forecast	2002	22.17	23.12	23.88	24.52	24.28	8.50	7.35	7.10	7.52	7.18	8.55	10.60	14.56

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
43	BONNERS FERRY, CITY OF	107		BASE	TBL load forecast	2003	20.26	19.91	19.31	20.84	21.26	6.78	5.57	2.75	2.23	2.69	6.34	5.44	11.12
44	BONNERS FERRY, CITY OF	107		LS	TBL load forecast	2003	22.29	23.27	24.04	24.54	24.36	8.53	7.39	7.16	7.58	7.24	8.56	10.60	14.63
45	BUREAU OF INDIAN AFFAIRS	482		BASE	TBL load forecast	2002	0.95	0.03	0.04	0.05	0.06	0.04	0.79	2.62	3.18	2.54	2.49	3.31	1.34
46	BUREAU OF INDIAN AFFAIRS	482		LS	TBL load forecast	2002	0.95	0.03	0.04	0.05	0.06	0.04	0.79	2.62	3.18	2.54	2.49	3.31	1.34
47	BUREAU OF INDIAN AFFAIRS	482		BASE	TBL load forecast	2003	0.96	0.03	0.04	0.05	0.06	0.04	0.79	2.63	3.20	2.55	2.51	3.33	1.35
48	BUREAU OF INDIAN AFFAIRS	482		LS	TBL load forecast	2003	0.96	0.03	0.04	0.05	0.06	0.04	0.79	2.63	3.20	2.55	2.51	3.33	1.35
49	BURLEY, CITY OF	109		BASE	TBL load forecast	2002	15.78	18.54	22.83	22.28	21.80	18.06	15.72	14.70	15.69	16.97	17.91	15.84	18.01
50	BURLEY, CITY OF	109		LS	TBL load forecast	2002	15.78	18.54	22.83	22.28	21.80	18.06	15.72	14.70	15.69	16.97	17.91	15.84	18.01
51	BURLEY, CITY OF	109		BASE	TBL load forecast	2003	15.92	18.70	23.04	22.47	21.99	18.22	15.86	14.83	15.83	17.12	18.07	15.98	18.17
52	BURLEY, CITY OF	109		LS	TBL load forecast	2003	15.92	18.70	23.04	22.47	21.99	18.22	15.86	14.83	15.83	17.12	18.07	15.98	18.17
53	CANBY, CITY OF, UTILITY B	111		BASE	T_PGE except 1MW	2002	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
54	CANBY, CITY OF, UTILITY B	111		LS	T_PGE except 1MW	2002	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
55	CANBY, CITY OF, UTILITY B	111		BASE	T_PGE except 1MW	2003	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
56	CANBY, CITY OF, UTILITY B	111		LS	T_PGE except 1MW	2003	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
57	CASCADE LOCKS, CITY OF	115		BASE	TBL load forecast	2002	3.21	3.66	4.38	3.55	4.83	3.74	3.06	2.46	2.19	2.33	2.41	2.28	3.18
58	CASCADE LOCKS, CITY OF	115		LS	TBL load forecast	2002	3.21	3.66	4.38	3.55	4.83	3.74	3.06	2.46	2.19	2.33	2.41	2.28	3.18
59	CASCADE LOCKS, CITY OF	115		BASE	TBL load forecast	2003	3.28	3.74	4.47	3.62	4.93	3.81	3.12	2.51	2.23	2.37	2.46	2.33	3.24
60	CASCADE LOCKS, CITY OF	115		LS	TBL load forecast	2003	3.28	3.74	4.47	3.62	4.93	3.81	3.12	2.51	2.23	2.37	2.46	2.33	3.24
61	CENTRAL ELECTRIC COOPERAT	312	PNGC	BASE	TBL load forecast	2002	93.38	80.88	105.57	117.87	104.59	90.01	73.43	67.58	58.04	63.95	66.21	56.48	81.50
62	CENTRAL ELECTRIC COOPERAT	312	PNGC	LS	TBL load forecast	2002	93.38	80.88	105.57	117.87	104.59	90.01	73.43	67.58	58.04	63.95	66.21	56.48	81.50
63	CENTRAL ELECTRIC COOPERAT	312	PNGC	BASE	TBL load forecast	2003	94.09	81.50	106.37	118.77	105.38	90.70	73.99	68.10	58.49	64.44	66.72	56.91	82.12
64	CENTRAL ELECTRIC COOPERAT	312	PNGC	LS	TBL load forecast	2003	94.09	81.50	106.37	118.77	105.38	90.70	73.99	68.10	58.49	64.44	66.72	56.91	82.12
65	CENTRAL LINCOLN PUD	207		BASE	TBL load forecast	2002	180.12	162.23	211.80	212.43	218.06	200.06	178.60	152.08	124.75	127.49	133.02	135.56	169.68
66	CENTRAL LINCOLN PUD	207		LS	TBL load forecast	2002	181.99	164.10	213.67	214.30	219.93	201.93	180.27	153.75	126.42	129.16	134.69	137.23	171.45
67	CENTRAL LINCOLN PUD	207		BASE	TBL load forecast	2003	183.05	164.89	215.22	215.86	221.58	203.30	182.98	156.06	128.31	131.09	136.70	139.28	173.19
68	CENTRAL LINCOLN PUD	207		LS	TBL load forecast	2003	184.72	166.56	216.89	217.53	223.25	204.97	182.98	156.06	128.31	131.09	136.70	139.28	174.03
69	CENTRAL MONTANA ELECTRIC	313		BASE	OY99 NWPP Op Pgm	2002	55.01	54.99	86.74	107.86	64.73	85.49	54.32	56.17	64.45	60.07	58.25	44.55	66.05
70	CENTRAL MONTANA ELECTRIC	313		LS	OY99 NWPP Op Pgm	2002	96.56	115.64	171.11	189.65	147.52	155.49	120.63	95.29	114.00	110.40	109.92	80.95	125.60
71	CENTRAL MONTANA ELECTRIC	313		BASE	OY99 NWPP Op Pgm	2003	55.55	55.75	87.87	108.00	65.21	85.99	55.00	56.97	65.38	61.07	58.32	44.57	66.64
72	CENTRAL MONTANA ELECTRIC	313		LS	OY99 NWPP Op Pgm	2003	97.10	116.40	172.24	189.78	148.00	155.99	121.31	96.09	114.93	111.41	110.00	80.97	126.19
73	CENTRALIA, CITY OF	119		BASE	TBL load forecast	2002	30.77	30.84	37.81	37.02	39.78	32.17	26.04	21.04	17.68	14.41	16.52	20.05	27.01
74	CENTRALIA, CITY OF	119		LS	TBL load forecast	2002	30.77	30.84	37.81	37.02	39.78	32.17	26.04	21.04	17.68	14.41	16.52	20.05	27.01
75	CENTRALIA, CITY OF	119		BASE	TBL load forecast	2003	31.08	31.14	38.19	37.39	40.18	32.49	26.30	21.25	17.85	14.55	16.68	20.25	27.28
76	CENTRALIA, CITY OF	119		LS	TBL load forecast	2003	31.08	31.14	38.19	37.39	40.18	32.49	26.30	21.25	17.85	14.55	16.68	20.25	27.28
77	CHENEY, CITY OF	123		BASE	TBL load forecast	2002	19.30	20.70	22.80	25.60	26.20	21.10	18.50	16.10	13.70	14.40	14.90	14.30	18.97
78	CHENEY, CITY OF	123		LS	TBL load forecast	2002	19.32	20.73	22.83	25.61	26.24	21.09	18.51	16.06	13.73	14.35	14.87	14.33	18.97
79	CHENEY, CITY OF	123		BASE	TBL load forecast	2003	19.74	21.18	23.33	26.16	26.82	21.55	18.92	16.41	14.03	14.66	15.19	14.64	19.39
80	CHENEY, CITY OF	123		LS	TBL load forecast	2003	19.74	21.18	23.33	26.16	26.82	21.55	18.92	16.41	14.03	14.66	15.19	14.64	19.39
81	CHEWELAH, CITY OF	124		BASE	TBL load forecast	2002	3.76	4.24	4.78	4.22	4.30	3.41	2.96	2.65	2.44	3.06	3.42	3.15	3.53
82	CHEWELAH, CITY OF	124		LS	TBL load forecast	2002	3.76	4.24	4.78	4.22	4.30	3.41	2.96	2.65	2.44	3.06	3.42	3.15	3.53
83	CHEWELAH, CITY OF	124		BASE	TBL load forecast	2003	3.77	4.24	4.78	4.23	4.30	3.42	2.96	2.65	2.44	3.07	3.42	3.16	3.54
84	CHEWELAH, CITY OF	124		LS	TBL load forecast	2003	3.77	4.24	4.78	4.23	4.30	3.42	2.96	2.65	2.44	3.07	3.42	3.16	3.54

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
85	CLALLAM COUNTY PUD NO 1	213		BASE	TBL load forecast	2002	103.05	93.37	123.88	128.33	134.17	109.05	88.03	61.90	56.39	54.14	52.47	54.60	88.28
86	CLALLAM COUNTY PUD NO 1	213		LS	TBL load forecast	2002	103.05	93.37	123.88	128.33	134.17	109.05	88.03	61.90	56.39	54.14	52.47	54.60	88.28
87	CLALLAM COUNTY PUD NO 1	213		BASE	TBL load forecast	2003	104.08	94.30	125.12	129.62	135.52	110.14	88.91	62.52	56.96	54.68	53.00	55.15	89.17
88	CLALLAM COUNTY PUD NO 1	213		LS	TBL load forecast	2003	104.08	94.30	125.12	129.62	135.52	110.14	88.91	62.52	56.96	54.68	53.00	55.15	89.17
89	CLARK COUNTY PUD NO 1	216	PPL	BASE	12/98 White Book	2002	387.46	444.41	602.02	606.92	568.03	426.56	430.10	292.60	192.32	326.36	324.36	319.91	410.09
90	CLARK COUNTY PUD NO 1	216	PPL	LS	12/98 White Book	2002	619.63	707.96	804.75	806.26	840.87	599.14	498.01	491.51	355.16	347.37	423.40	444.29	578.20
91	CLARK COUNTY PUD NO 1	216	PPL	BASE	12/98 White Book	2003	397.17	454.21	612.20	617.33	582.11	435.50	437.72	300.76	198.23	331.90	330.96	327.14	418.77
92	CLARK COUNTY PUD NO 1	216	PPL	LS	12/98 White Book	2003	629.34	717.76	814.93	816.66	854.95	608.08	505.63	499.67	361.07	352.92	430.00	451.52	586.88
93	CLEARWATER POWER COMPANY	315		BASE	TBL load forecast	2002	33.34	34.07	41.02	40.78	42.21	34.65	28.82	24.13	20.57	21.16	21.62	20.43	30.23
94	CLEARWATER POWER COMPANY	315		LS	TBL load forecast	2002	33.34	34.07	41.02	40.78	42.21	34.65	28.82	24.13	20.57	21.16	21.62	20.43	30.23
95	CLEARWATER POWER COMPANY	315		BASE	TBL load forecast	2003	33.63	34.36	41.37	41.12	42.56	34.95	29.07	24.33	20.75	21.34	21.80	20.61	30.49
96	CLEARWATER POWER COMPANY	315		LS	TBL load forecast	2003	33.63	34.36	41.37	41.12	42.56	34.95	29.07	24.33	20.75	21.34	21.80	20.61	30.49
97	COLUMBIA BASIN ELECTRIC C	318		BASE	TBL load forecast	2002	16.14	13.35	16.91	13.72	18.44	15.53	17.85	20.29	19.96	17.96	19.05	17.50	17.23
98	COLUMBIA BASIN ELECTRIC C	318		LS	TBL load forecast	2002	16.14	13.35	16.91	13.72	18.44	15.53	17.85	20.29	19.96	17.96	19.05	17.50	17.23
99	COLUMBIA BASIN ELECTRIC C	318		BASE	TBL load forecast	2003	16.46	13.61	17.24	13.99	18.81	15.84	18.21	20.69	20.36	18.32	19.43	17.84	17.57
100	COLUMBIA BASIN ELECTRIC C	318		LS	TBL load forecast	2003	16.46	13.61	17.24	13.99	18.81	15.84	18.21	20.69	20.36	18.32	19.43	17.84	17.57
101	COLUMBIA POWER COOPERATIV	321		BASE	TBL load forecast	2002	4.02	3.47	4.97	5.17	5.33	3.87	3.40	3.43	3.91	4.86	5.11	4.14	4.31
102	COLUMBIA POWER COOPERATIV	321		LS	TBL load forecast	2002	4.02	3.47	4.97	5.17	5.33	3.87	3.40	3.43	3.91	4.86	5.11	4.14	4.31
103	COLUMBIA POWER COOPERATIV	321		BASE	TBL load forecast	2003	4.10	3.50	5.00	5.20	5.40	3.90	3.40	3.50	3.90	4.90	5.20	4.20	4.35
104	COLUMBIA POWER COOPERATIV	321		LS	TBL load forecast	2003	4.05	3.50	5.02	5.21	5.37	3.90	3.43	3.46	3.94	4.89	5.15	4.18	4.34
105	COLUMBIA RIVER PUD	221		BASE	TBL load forecast	2002	46.91	47.51	51.87	54.01	56.53	48.44	45.02	38.28	31.85	40.02	38.78	39.37	44.88
106	COLUMBIA RIVER PUD	221		LS	TBL load forecast	2002	46.91	47.51	51.87	54.01	56.53	48.44	45.02	38.28	31.85	40.02	38.78	39.37	44.88
107	COLUMBIA RIVER PUD	221		BASE	TBL load forecast	2003	47.69	48.30	52.73	54.91	57.48	49.25	45.77	38.92	32.38	40.68	39.43	40.03	45.63
108	COLUMBIA RIVER PUD	221		LS	TBL load forecast	2003	47.69	48.30	52.73	54.91	57.48	49.25	45.77	38.92	32.38	40.68	39.43	40.03	45.63
109	COLUMBIA RURAL ELECTRIC A	324		BASE	TBL load forecast	2002	24.69	18.59	21.62	21.97	23.99	19.18	38.29	53.38	75.70	103.37	107.26	62.50	47.54
110	COLUMBIA RURAL ELECTRIC A	324		LS	TBL load forecast	2002	24.69	18.59	21.62	21.97	23.99	19.18	38.29	53.38	75.70	103.37	107.26	62.50	47.54
111	COLUMBIA RURAL ELECTRIC A	324		BASE	TBL load forecast	2003	25.40	19.13	22.24	22.60	24.68	19.74	39.40	54.92	77.89	106.36	110.37	64.31	48.92
112	COLUMBIA RURAL ELECTRIC A	324		LS	TBL load forecast	2003	25.40	19.13	22.24	22.60	24.68	19.74	39.40	54.92	77.89	106.36	110.37	64.31	48.92
113	CONSOLIDATED IRRIGATION D	192		BASE	TBL load forecast	2002	0.54	0.89	0.88	0.74	0.79	0.29	0.38	0.31	0.42	0.41	0.39	0.35	0.53
114	CONSOLIDATED IRRIGATION D	192		LS	TBL load forecast	2002	1.01	1.42	0.96	1.30	1.16	0.47	0.55	0.51	0.58	0.67	0.64	0.59	0.82
115	CONSOLIDATED IRRIGATION D	192		BASE	TBL load forecast	2003	0.54	0.89	0.88	0.74	0.79	0.29	0.38	0.31	0.42	0.42	0.39	0.35	0.53
116	CONSOLIDATED IRRIGATION D	192		LS	TBL load forecast	2003	1.01	1.43	0.97	1.30	1.16	0.48	0.55	0.52	0.59	0.68	0.64	0.59	0.83
117	CONSUMERS POWER INC	327	PNGC	BASE	TBL load forecast	2002	72.12	72.01	91.32	90.06	100.44	77.21	68.42	54.83	43.93	50.61	56.25	45.14	68.53
118	CONSUMERS POWER INC	327	PNGC	LS	TBL load forecast	2002	72.12	72.01	91.32	90.06	100.44	77.21	68.42	54.83	43.93	50.61	56.25	45.14	68.53
119	CONSUMERS POWER INC	327	PNGC	BASE	TBL load forecast	2003	74.64	74.53	94.52	93.21	103.95	79.92	70.81	56.75	45.47	52.38	58.22	46.72	70.93
120	CONSUMERS POWER INC	327	PNGC	LS	TBL load forecast	2003	74.64	74.53	94.52	93.21	103.95	79.92	70.81	56.75	45.47	52.38	58.22	46.72	70.93
121	COOS-CURRY ELECTRIC COOPE	330	PNGC	BASE	TBL load forecast	2002	57.02	58.27	66.22	65.15	72.83	68.95	55.74	46.78	35.14	35.77	35.07	34.50	52.62
122	COOS-CURRY ELECTRIC COOPE	330	PNGC	LS	TBL load forecast	2002	58.11	59.36	67.31	66.24	73.92	70.04	56.72	47.76	36.12	36.75	36.05	35.48	53.66
123	COOS-CURRY ELECTRIC COOPE	330	PNGC	BASE	TBL load forecast	2003	58.15	59.42	67.51	66.41	74.22	70.28	57.70	48.59	36.75	37.39	36.68	36.10	54.10
124	COOS-CURRY ELECTRIC COOPE	330	PNGC	LS	TBL load forecast	2003	59.13	60.40	68.49	67.39	75.20	71.26	57.70	48.59	36.75	37.39	36.68	36.10	54.59
125	COULEE DAM, CITY OF	125		BASE	TBL load forecast	2002	2.35	3.50	4.43	4.88	4.97	3.52	2.32	1.88	1.31	1.50	1.79	1.44	2.82

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
126	COULEE DAM, CITY OF	125		LS	TBL load forecast	2002	2.52	3.67	4.60	5.05	5.14	3.69	2.47	2.03	1.46	1.65	1.94	1.59	2.98
127	COULEE DAM, CITY OF	125		BASE	TBL load forecast	2003	2.38	3.55	4.48	4.94	5.02	3.56	2.48	2.04	1.46	1.66	1.95	1.60	2.93
128	COULEE DAM, CITY OF	125		LS	TBL load forecast	2003	2.53	3.70	4.63	5.09	5.17	3.71	2.48	2.04	1.46	1.66	1.95	1.60	3.00
129	COWLITZ COUNTY PUD NO 1	222		BASE	OY99 NWPP Op Pgm	2002	425.47	460.74	473.11	481.63	466.62	458.60	416.58	364.40	428.40	353.11	364.91	417.39	425.91
130	COWLITZ COUNTY PUD NO 1	222		LS	OY99 NWPP Op Pgm	2002	499.47	534.74	547.11	555.63	540.62	532.60	490.58	438.40	502.40	427.11	438.91	491.39	499.91
131	COWLITZ COUNTY PUD NO 1	222		BASE	OY99 NWPP Op Pgm	2003	428.24	464.26	476.73	482.03	468.37	460.30	419.34	368.10	432.49	357.00	365.21	417.50	428.30
132	COWLITZ COUNTY PUD NO 1	222		LS	OY99 NWPP Op Pgm	2003	502.24	538.26	550.73	556.03	542.37	534.30	493.34	442.10	506.49	431.00	439.21	491.50	502.30
133	DECLO, CITY OF	127		BASE	TBL load forecast	2002	0.49	0.53	0.63	0.67	0.64	0.54	0.50	0.39	0.30	0.33	0.35	0.37	0.48
134	DECLO, CITY OF	127		LS	TBL load forecast	2002	0.50	0.50	0.60	0.70	0.60	0.50	0.50	0.40	0.30	0.30	0.40	0.40	0.48
135	DECLO, CITY OF	127		BASE	TBL load forecast	2003	0.49	0.53	0.64	0.67	0.64	0.54	0.51	0.40	0.31	0.33	0.35	0.37	0.48
136	DECLO, CITY OF	127		LS	TBL load forecast	2003	0.49	0.53	0.64	0.67	0.64	0.54	0.51	0.40	0.31	0.33	0.35	0.37	0.48
137	DOUGLAS ELECTRIC COOPERAT	333	PNGC	BASE	TBL load forecast	2002	28.11	28.08	36.28	35.73	36.64	33.09	27.44	21.26	17.49	19.93	21.27	20.07	27.12
138	DOUGLAS ELECTRIC COOPERAT	333	PNGC	LS	TBL load forecast	2002	28.11	28.08	36.28	35.73	36.64	33.09	27.44	21.26	17.49	19.93	21.27	20.07	27.12
139	DOUGLAS ELECTRIC COOPERAT	333	PNGC	BASE	TBL load forecast	2003	28.79	28.75	37.15	36.59	37.52	33.89	28.10	21.77	17.91	20.41	21.78	20.55	27.77
140	DOUGLAS ELECTRIC COOPERAT	333	PNGC	LS	TBL load forecast	2003	28.79	28.75	37.15	36.59	37.52	33.89	28.10	21.77	17.91	20.41	21.78	20.55	27.77
141	DRAIN, CITY OF	128		BASE	TBL load forecast	2002	4.13	3.98	4.78	5.01	5.14	4.27	4.01	3.54	3.05	3.23	3.15	3.22	3.96
142	DRAIN, CITY OF	128		LS	TBL load forecast	2002	4.10	4.00	4.80	5.00	5.10	4.30	4.00	3.50	3.10	3.20	3.20	3.20	3.96
143	DRAIN, CITY OF	128		BASE	TBL load forecast	2003	4.21	4.06	4.87	5.11	5.24	4.35	4.09	3.61	3.11	3.29	3.21	3.28	4.04
144	DRAIN, CITY OF	128		LS	TBL load forecast	2003	4.21	4.06	4.87	5.11	5.24	4.35	4.09	3.61	3.11	3.29	3.21	3.28	4.04
145	EAST END MUTUAL ELECTRIC	335		BASE	TBL load forecast	2002	2.26	2.42	3.43	2.81	1.75	2.03	2.27	1.93	2.34	3.71	3.61	2.49	2.59
146	EAST END MUTUAL ELECTRIC	335		LS	TBL load forecast	2002	2.26	2.42	3.43	2.81	1.75	2.03	2.27	1.93	2.34	3.71	3.61	2.49	2.59
147	EAST END MUTUAL ELECTRIC	335		BASE	TBL load forecast	2003	2.28	2.44	3.46	2.84	1.76	2.05	2.29	1.94	2.37	3.74	3.64	2.51	2.61
148	EAST END MUTUAL ELECTRIC	335		LS	TBL load forecast	2003	2.28	2.44	3.46	2.84	1.76	2.05	2.29	1.94	2.37	3.74	3.64	2.51	2.61
149	EATONVILLE, TOWN OF	131		BASE	TBL load forecast	2002	4.94	5.37	6.38	6.76	6.63	4.41	3.97	3.55	2.50	2.34	2.32	3.38	4.38
150	EATONVILLE, TOWN OF	131		LS	TBL load forecast	2002	4.90	5.40	6.40	6.80	6.60	4.40	4.00	3.60	2.50	2.30	2.30	3.40	4.38
151	EATONVILLE, TOWN OF	131		BASE	TBL load forecast	2003	5.11	5.56	6.60	7.00	6.86	4.56	4.11	3.68	2.59	2.42	2.40	3.49	4.53
152	EATONVILLE, TOWN OF	131		LS	TBL load forecast	2003	5.11	5.56	6.60	7.00	6.86	4.56	4.11	3.68	2.59	2.42	2.40	3.49	4.53
153	ELLENSBURG, CITY OF	133		BASE	TBL load forecast	2002	31.32	32.04	33.68	37.15	35.54	29.45	27.25	28.54	23.24	24.34	28.37	28.15	29.92
154	ELLENSBURG, CITY OF	133		LS	TBL load forecast	2002	31.32	32.04	33.68	37.15	35.54	29.45	27.25	28.54	23.24	24.34	28.37	28.15	29.92
155	ELLENSBURG, CITY OF	133		BASE	TBL load forecast	2003	31.82	32.55	34.22	37.74	36.11	29.92	27.68	29.00	23.61	24.72	28.82	28.60	30.40
156	ELLENSBURG, CITY OF	133		LS	TBL load forecast	2003	31.82	32.55	34.22	37.74	36.11	29.92	27.68	29.00	23.61	24.72	28.82	28.60	30.40
157	ELMHURST MUTUAL POWER & L	334		BASE	TBL load forecast	2002	46.60	48.10	58.00	61.40	65.20	49.90	40.00	29.40	21.90	20.40	22.70	23.20	40.57
158	ELMHURST MUTUAL POWER & L	334		LS	TBL load forecast	2002	46.60	48.10	58.00	61.40	65.20	49.90	40.00	29.40	21.90	20.40	22.70	23.20	40.57
159	ELMHURST MUTUAL POWER & L	334		BASE	TBL load forecast	2003	47.51	49.02	59.11	62.55	66.44	50.84	40.77	30.01	22.31	20.82	23.14	23.66	41.35
160	ELMHURST MUTUAL POWER & L	334		LS	TBL load forecast	2003	47.50	49.00	59.10	62.60	66.40	50.80	40.80	30.00	22.30	20.80	23.10	23.70	41.34
161	ENERGY NORTHWEST INC.	841		BASE	recent tx bills	2002	13.81	24.61	24.92	26.46	30.86	18.36	15.20	14.15	10.49	16.75	13.68	12.32	18.47
162	ENERGY NORTHWEST INC.	841		LS	recent tx bills	2002	28.21	38.43	38.75	40.08	46.10	31.18	28.11	26.13	24.09	32.54	28.61	25.47	32.31
163	ENERGY NORTHWEST INC.	841		BASE	recent tx bills	2003	13.89	24.77	25.09	26.47	30.96	18.42	15.29	14.27	10.57	16.90	13.69	12.32	18.55
164	ENERGY NORTHWEST INC.	841		LS	recent tx bills	2003	28.36	38.68	39.00	40.11	46.25	31.28	28.27	26.35	24.29	32.84	28.63	25.48	32.46
165	FALL RIVER RURAL ELECTRIC	337		BASE	TBL load forecast	2002	25.02	28.30	36.09	34.61	34.88	26.29	20.83	20.92	36.72	43.34	35.13	21.05	30.27
166	FALL RIVER RURAL ELECTRIC	337		LS	TBL load forecast	2002	25.00	28.30	36.10	34.60	34.90	26.30	20.80	20.90	36.70	43.30	35.10	21.10	30.26
167	FALL RIVER RURAL ELECTRIC	337		BASE	TBL load forecast	2003	25.36	28.68	36.57	35.07	35.34	26.65	21.11	21.20	37.21	43.93	35.60	21.34	30.67

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
168	FALL RIVER RURAL ELECTRIC	337		LS	TBL load forecast	2003	25.36	28.68	36.57	35.07	35.34	26.65	21.11	21.20	37.21	43.93	35.60	21.34	30.67
169	FARMERS ELECTRIC COOPERAT	338		BASE	TBL load forecast	2002	0.70	0.79	0.96	1.05	0.99	0.79	0.61	0.54	0.40	0.49	0.48	0.41	0.68
170	FARMERS ELECTRIC COOPERAT	338		LS	TBL load forecast	2002	0.70	0.79	0.96	1.05	0.99	0.79	0.61	0.54	0.40	0.49	0.48	0.41	0.68
171	FARMERS ELECTRIC COOPERAT	338		BASE	TBL load forecast	2003	0.71	0.81	0.98	1.07	1.01	0.81	0.62	0.55	0.41	0.50	0.49	0.42	0.70
172	FARMERS ELECTRIC COOPERAT	338		LS	TBL load forecast	2003	0.71	0.81	0.98	1.07	1.01	0.81	0.62	0.55	0.41	0.50	0.49	0.42	0.70
173	FERRY COUNTY PUD NO 1	230		BASE	TBL load forecast	2002	17.09	18.38	20.13	22.37	21.99	18.15	15.93	14.64	13.03	12.81	13.37	13.13	16.75
174	FERRY COUNTY PUD NO 1	230		LS	TBL load forecast	2002	17.09	18.38	20.13	22.37	21.99	18.15	15.93	14.64	13.03	12.81	13.37	13.13	16.75
175	FERRY COUNTY PUD NO 1	230		BASE	TBL load forecast	2003	17.21	18.51	20.27	22.53	22.15	18.28	16.04	14.74	13.12	12.90	13.46	13.22	16.87
176	FERRY COUNTY PUD NO 1	230		LS	TBL load forecast	2003	17.21	18.51	20.27	22.53	22.15	18.28	16.04	14.74	13.12	12.90	13.46	13.22	16.87
177	FIRCREST, TOWN OF	140		BASE	TBL load forecast	2002	7.00	8.08	9.35	9.10	9.36	7.70	6.40	4.89	3.69	3.81	3.76	3.75	6.41
178	FIRCREST, TOWN OF	140		LS	TBL load forecast	2002	7.00	8.08	9.35	9.10	9.36	7.70	6.40	4.89	3.69	3.81	3.76	3.75	6.41
179	FIRCREST, TOWN OF	140		BASE	TBL load forecast	2003	7.02	8.10	9.37	9.12	9.38	7.72	6.41	4.90	3.69	3.82	3.77	3.76	6.42
180	FIRCREST, TOWN OF	140		LS	TBL load forecast	2003	7.02	8.10	9.37	9.12	9.38	7.72	6.41	4.90	3.69	3.82	3.77	3.76	6.42
181	FLATHEAD ELECTRIC COOPERA	339		BASE	modified BOS	2002	72.35	77.94	78.03	92.08	125.23	89.52	62.36	63.82	61.58	66.69	68.52	56.80	76.24
182	FLATHEAD ELECTRIC COOPERA	339		LS	modified BOS	2002	132.50	138.10	138.20	152.30	185.40	149.70	122.50	124.00	121.80	126.90	128.70	117.00	136.43
183	FLATHEAD ELECTRIC COOPERA	339		BASE	modified BOS	2003	76.24	82.00	82.09	96.55	130.66	93.91	66.11	67.61	65.30	70.57	72.46	60.39	80.32
184	FLATHEAD ELECTRIC COOPERA	339		LS	modified BOS	2003	136.41	142.17	142.26	156.72	190.83	154.08	126.11	127.61	125.30	130.57	132.46	120.39	140.41
185	FOREST GROVE, CITY OF	142		BASE	TBL load forecast	2002	32.51	31.35	40.39	41.45	45.65	33.21	27.70	19.87	20.86	21.25	19.07	22.36	29.64
186	FOREST GROVE, CITY OF	142		LS	TBL load forecast	2002	41.50	40.34	49.38	50.44	54.64	42.20	36.61	28.78	29.77	30.16	27.98	31.27	38.59
187	FOREST GROVE, CITY OF	142		BASE	TBL load forecast	2003	33.17	31.99	41.16	42.23	46.49	33.88	28.82	20.88	21.88	22.28	20.07	23.40	30.52
188	FOREST GROVE, CITY OF	142		LS	TBL load forecast	2003	42.08	40.90	50.07	51.14	55.40	42.79	37.12	29.18	30.18	30.58	28.37	31.70	39.13
189	FRANKLIN COUNTY PUD NO 1	233		BASE	TBL load forecast	2002	100.84	90.90	112.27	127.04	123.49	92.01	83.42	83.52	103.31	117.54	130.51	107.32	106.01
190	FRANKLIN COUNTY PUD NO 1	233		LS	TBL load forecast	2002	102.30	92.40	113.80	128.50	125.00	93.50	84.80	84.90	104.70	118.90	131.90	108.70	107.45
191	FRANKLIN COUNTY PUD NO 1	233		BASE	TBL load forecast	2003	103.47	93.29	115.18	130.30	126.66	94.43	86.80	86.90	107.17	121.75	135.03	111.28	109.36
192	FRANKLIN COUNTY PUD NO 1	233		LS	TBL load forecast	2003	104.80	94.60	116.50	131.60	128.00	95.80	86.80	86.90	107.20	121.80	135.00	111.30	110.03
193	GLACIER ELECTRIC COOPERAT	340		BASE	TBL load forecast	2002	23.66	26.50	28.65	30.15	30.26	26.26	22.41	20.62	20.30	19.41	18.83	19.40	23.87
194	GLACIER ELECTRIC COOPERAT	340		LS	TBL load forecast	2002	23.66	26.50	28.65	30.15	30.26	26.26	22.41	20.62	20.30	19.41	18.83	19.40	23.87
195	GLACIER ELECTRIC COOPERAT	340		BASE	TBL load forecast	2003	23.95	26.82	28.99	30.51	30.63	26.57	22.68	20.87	20.55	19.64	19.05	19.63	24.16
196	GLACIER ELECTRIC COOPERAT	340		LS	TBL load forecast	2003	23.95	26.82	28.99	30.51	30.63	26.57	22.68	20.87	20.55	19.64	19.05	19.63	24.16
197	HARNEY ELECTRIC COOPERATI	341		BASE	TBL load forecast	2002	9.65	7.69	10.19	11.90	11.22	11.11	13.53	20.81	21.54	31.29	30.25	27.71	17.24
198	HARNEY ELECTRIC COOPERATI	341		LS	TBL load forecast	2002	9.70	7.70	10.20	11.90	11.20	11.10	13.50	20.80	21.50	31.30	30.30	27.70	17.24
199	HARNEY ELECTRIC COOPERATI	341		BASE	TBL load forecast	2003	9.70	7.73	10.24	11.96	11.28	11.16	13.59	20.91	21.65	31.45	30.40	27.85	17.33
200	HARNEY ELECTRIC COOPERATI	341		LS	TBL load forecast	2003	9.70	7.73	10.24	11.96	11.28	11.16	13.59	20.91	21.65	31.45	30.40	27.85	17.33
201	HEYBURN, CITY OF	150		BASE	TBL load forecast	2002	15.09	15.17	15.88	16.50	16.48	16.09	8.83	13.27	13.60	13.70	12.86	13.53	14.25
202	HEYBURN, CITY OF	150		LS	TBL load forecast	2002	15.09	15.17	15.88	16.50	16.48	16.09	8.83	13.27	13.60	13.70	12.86	13.53	14.25
203	HEYBURN, CITY OF	150		BASE	TBL load forecast	2003	15.18	15.26	15.97	16.59	16.57	16.19	8.89	13.34	13.68	13.78	12.93	13.61	14.33
204	HEYBURN, CITY OF	150		LS	TBL load forecast	2003	15.18	15.26	15.97	16.59	16.57	16.19	8.89	13.34	13.68	13.78	12.93	13.61	14.33
205	HOOD RIVER ELECTRIC COOPE	342		BASE	TBL load forecast	2002	19.27	19.51	20.10	21.67	21.52	18.06	15.96	12.07	9.72	9.48	12.94	15.46	16.31
206	HOOD RIVER ELECTRIC COOPE	342		LS	TBL load forecast	2002	19.27	19.51	20.10	21.67	21.52	18.06	15.96	12.07	9.72	9.48	12.94	15.46	16.31
207	HOOD RIVER ELECTRIC COOPE	342		BASE	TBL load forecast	2003	19.50	19.74	20.34	21.93	21.77	18.28	16.16	12.22	9.83	9.59	13.10	15.65	16.51
208	HOOD RIVER ELECTRIC COOPE	342		LS	TBL load forecast	2003	19.50	19.70	20.30	21.90	21.80	18.30	16.20	12.20	9.80	9.60	13.10	15.70	16.51

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209	IDAHO COUNTY LIGHT & POWE	345		BASE	TBL load forecast	2002	7.32	7.48	9.57	9.32	9.92	7.86	6.26	5.52	4.36	4.90	4.87	4.24	6.80
210	IDAHO COUNTY LIGHT & POWE	345		LS	TBL load forecast	2002	7.52	7.68	9.77	9.52	10.12	8.06	6.44	5.70	4.54	5.08	5.05	4.42	6.99
211	IDAHO COUNTY LIGHT & POWE	345		BASE	TBL load forecast	2003	7.37	7.53	9.63	9.39	9.98	7.92	6.47	5.73	4.56	5.10	5.07	4.43	6.93
212	IDAHO COUNTY LIGHT & POWE	345		LS	TBL load forecast	2003	7.55	7.71	9.81	9.57	10.16	8.10	6.47	5.73	4.56	5.10	5.07	4.43	7.02
213	INLAND POWER & LIGHT COMP	348		BASE	TBL load forecast	2002	135.03	139.09	162.63	168.44	162.63	142.28	127.94	114.66	108.65	102.26	110.17	112.56	132.20
214	INLAND POWER & LIGHT COMP	348		LS	TBL load forecast	2002	136.15	140.21	163.75	169.56	163.75	143.40	128.94	115.66	109.65	103.26	111.17	113.56	133.26
215	INLAND POWER & LIGHT COMP	348		BASE	TBL load forecast	2003	135.87	139.95	163.65	169.50	163.65	143.17	129.61	116.24	110.19	103.76	111.72	114.12	133.45
216	INLAND POWER & LIGHT COMP	348		LS	TBL load forecast	2003	136.87	140.95	164.65	170.50	164.65	144.17	129.61	116.24	110.19	103.76	111.72	114.12	133.95
217	KITTITAS COUNTY PUD NO 1	246		BASE	TBL load forecast	2002	6.21	6.71	8.64	9.15	9.46	6.11	3.62	3.52	2.70	3.36	3.49	2.35	5.44
218	KITTITAS COUNTY PUD NO 1	246		LS	TBL load forecast	2002	10.05	10.55	12.48	12.99	13.30	9.95	7.45	7.35	6.53	7.19	7.32	6.18	9.28
219	KITTITAS COUNTY PUD NO 1	246		BASE	TBL load forecast	2003	6.23	6.73	8.66	9.17	9.49	6.13	3.66	3.56	2.73	3.40	3.52	2.38	5.47
220	KITTITAS COUNTY PUD NO 1	246		LS	TBL load forecast	2003	10.06	10.56	12.49	13.00	13.32	9.96	7.46	7.36	6.53	7.20	7.32	6.18	9.29
221	KOOTENAI ELECTRIC COOPERA	351		BASE	TBL load forecast	2002	44.70	48.02	57.69	58.05	60.79	48.75	39.24	33.69	30.08	31.64	31.54	28.79	42.75
222	KOOTENAI ELECTRIC COOPERA	351		LS	TBL load forecast	2002	44.70	48.00	57.70	58.10	60.80	48.80	39.20	33.70	30.10	31.60	31.50	28.80	42.75
223	KOOTENAI ELECTRIC COOPERA	351		BASE	TBL load forecast	2003	45.24	48.60	58.38	58.75	61.52	49.34	39.71	34.09	30.44	32.02	31.92	29.13	43.26
224	KOOTENAI ELECTRIC COOPERA	351		LS	TBL load forecast	2003	45.24	48.60	58.38	58.75	61.52	49.34	39.71	34.09	30.44	32.02	31.92	29.13	43.26
225	LAKEVIEW LIGHT & POWER CO	353		BASE	TBL load forecast	2002	42.00	43.21	53.30	54.08	53.35	45.35	40.68	35.13	32.76	36.08	33.26	32.63	41.82
226	LAKEVIEW LIGHT & POWER CO	353		LS	TBL load forecast	2002	42.00	43.21	53.30	54.08	53.35	45.35	40.68	35.13	32.76	36.08	33.26	32.63	41.82
227	LAKEVIEW LIGHT & POWER CO	353		BASE	TBL load forecast	2003	42.15	43.36	53.50	54.27	53.54	45.51	40.83	35.26	32.88	36.21	33.38	32.75	41.97
228	LAKEVIEW LIGHT & POWER CO	353		LS	TBL load forecast	2003	42.15	43.36	53.50	54.27	53.54	45.51	40.83	35.26	32.88	36.21	33.38	32.75	41.97
229	LANE ELECTRIC COOPERATIVE	354	PNGC	BASE	TBL load forecast	2002	44.00	44.10	58.80	58.20	64.40	50.90	39.80	29.40	21.70	22.00	22.90	21.20	39.78
230	LANE ELECTRIC COOPERATIVE	354	PNGC	LS	TBL load forecast	2002	44.70	44.90	59.50	58.90	65.20	51.70	40.40	30.00	22.30	22.60	23.50	21.80	40.46
231	LANE ELECTRIC COOPERATIVE	354	PNGC	BASE	TBL load forecast	2003	44.98	45.12	60.05	59.46	65.81	52.05	41.25	30.64	22.77	23.10	24.00	22.28	40.96
232	LANE ELECTRIC COOPERATIVE	354	PNGC	LS	TBL load forecast	2003	45.65	45.79	60.72	60.13	66.48	52.72	41.25	30.64	22.77	23.10	24.00	22.28	41.29
233	LEWIS COUNTY PUD NO 1	253		BASE	TBL load forecast	2002	179.52	168.40	191.41	181.89	206.99	172.26	148.62	131.03	110.68	116.92	114.74	109.88	152.70
234	LEWIS COUNTY PUD NO 1	253		LS	TBL load forecast	2002	179.52	168.40	191.41	181.89	206.99	172.26	148.62	131.03	110.68	116.92	114.74	109.88	152.70
235	LEWIS COUNTY PUD NO 1	253		BASE	TBL load forecast	2003	179.97	168.82	191.89	182.34	207.51	172.69	149.00	131.36	110.96	117.22	115.03	110.15	153.08
236	LEWIS COUNTY PUD NO 1	253		LS	TBL load forecast	2003	179.97	168.82	191.89	182.34	207.51	172.69	149.00	131.36	110.96	117.22	115.03	110.15	153.08
237	LINCOLN ELECTRIC COOPERAT	357		BASE	TBL load forecast	2002	13.86	12.74	17.34	21.12	20.83	17.38	15.43	12.97	10.68	11.55	10.83	9.26	14.50
238	LINCOLN ELECTRIC COOPERAT	357		LS	TBL load forecast	2002	14.10	12.90	17.50	21.30	21.00	17.60	15.60	13.10	10.90	11.70	11.00	9.40	14.68
239	LINCOLN ELECTRIC COOPERAT	357		BASE	TBL load forecast	2003	13.90	12.79	17.39	21.19	20.89	17.44	15.63	13.16	10.87	11.75	11.02	9.45	14.62
240	LINCOLN ELECTRIC COOPERAT	357		LS	TBL load forecast	2003	14.07	12.96	17.56	21.36	21.06	17.61	15.63	13.16	10.87	11.75	11.02	9.45	14.71
241	LOST RIVER ELECTRIC COOPE	359	PNGC	BASE	TBL load forecast	2002	4.37	5.42	7.00	7.26	6.86	4.64	3.93	6.61	11.30	17.08	14.36	7.37	8.02
242	LOST RIVER ELECTRIC COOPE	359	PNGC	LS	TBL load forecast	2002	4.37	5.42	7.00	7.26	6.86	4.64	3.93	6.61	11.30	17.08	14.36	7.37	8.02
243	LOST RIVER ELECTRIC COOPE	359	PNGC	BASE	TBL load forecast	2003	4.39	5.45	7.03	7.29	6.90	4.67	3.95	6.64	11.36	17.17	14.43	7.41	8.06
244	LOST RIVER ELECTRIC COOPE	359	PNGC	LS	TBL load forecast	2003	4.39	5.45	7.03	7.29	6.90	4.67	3.95	6.64	11.36	17.17	14.43	7.41	8.06
245	LOWER VALLEY POWER & LIGH	360		BASE	TBL load forecast	2002	79.40	91.10	126.30	126.00	126.40	92.00	70.00	58.70	46.90	61.30	54.20	49.30	81.80
246	LOWER VALLEY POWER & LIGH	360		LS	TBL load forecast	2002	79.44	91.05	126.31	125.96	126.44	91.99	69.97	58.67	46.90	61.31	54.15	49.26	81.79
247	LOWER VALLEY POWER & LIGH	360		BASE	TBL load forecast	2003	81.03	92.87	128.84	128.48	128.98	93.84	71.37	59.85	47.84	62.54	55.24	50.24	83.43
248	LOWER VALLEY POWER & LIGH	360		LS	TBL load forecast	2003	81.03	92.87	128.84	128.48	128.98	93.84	71.37	59.85	47.84	62.54	55.24	50.24	83.43
249	MASON COUNTY PUD 1	257		BASE	TBL load forecast	2002	9.95	9.65	12.91	13.72	13.22	10.61	8.80	7.45	5.62	5.76	5.60	5.20	9.04

Appendix B

NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
250	MASON COUNTY PUD 1	257		LS	TBL load forecast	2002	9.95	9.65	12.91	13.72	13.22	10.61	8.80	7.45	5.62	5.76	5.60	5.20	9.04
251	MASON COUNTY PUD 1	257		BASE	TBL load forecast	2003	10.00	9.70	12.97	13.78	13.29	10.66	8.84	7.49	5.64	5.79	5.63	5.22	9.08
252	MASON COUNTY PUD 1	257		LS	TBL load forecast	2003	10.00	9.70	12.97	13.78	13.29	10.66	8.84	7.49	5.64	5.79	5.63	5.22	9.08
253	MASON COUNTY PUD 3	258		BASE	TBL load forecast	2002	104.64	104.37	130.94	134.31	139.43	115.62	95.50	79.27	62.07	64.67	62.54	62.50	96.32
254	MASON COUNTY PUD 3	258		LS	TBL load forecast	2002	104.60	104.40	130.90	134.30	139.40	115.60	95.50	79.30	62.10	64.70	62.50	62.50	96.32
255	MASON COUNTY PUD 3	258		BASE	TBL load forecast	2003	107.20	106.90	134.10	137.60	142.80	118.40	97.80	81.20	63.60	66.20	64.10	64.00	98.66
256	MASON COUNTY PUD 3	258		LS	TBL load forecast	2003	107.17	106.89	134.11	137.56	142.80	118.41	97.80	81.19	63.57	66.23	64.05	64.01	98.65
257	MCCLEARY, CITY OF	154		BASE	TBL load forecast	2002	6.70	6.50	7.78	7.78	8.20	7.13	6.34	5.69	4.92	4.89	4.61	4.66	6.27
258	MCCLEARY, CITY OF	154		LS	TBL load forecast	2002	6.70	6.50	7.78	7.78	8.20	7.13	6.34	5.69	4.92	4.89	4.61	4.66	6.27
259	MCCLEARY, CITY OF	154		BASE	TBL load forecast	2003	6.77	6.57	7.86	7.86	8.30	7.21	6.41	5.75	4.97	4.95	4.66	4.71	6.34
260	MCCLEARY, CITY OF	154		LS	TBL load forecast	2003	6.77	6.57	7.86	7.86	8.30	7.21	6.41	5.75	4.97	4.95	4.66	4.71	6.34
261	MCMINNVILLE, CITY OF	155		BASE	TBL load forecast	2002	120.77	133.16	136.91	133.63	159.56	114.00	119.02	111.26	103.96	99.66	89.79	83.13	117.07
262	MCMINNVILLE, CITY OF	155		LS	TBL load forecast	2002	121.70	134.00	137.80	134.50	160.40	114.90	119.80	112.00	104.70	100.40	90.60	83.90	117.89
263	MCMINNVILLE, CITY OF	155		BASE	TBL load forecast	2003	123.28	135.92	139.74	136.40	162.85	116.38	122.18	114.27	106.82	102.43	92.37	85.58	119.85
264	MCMINNVILLE, CITY OF	155		LS	TBL load forecast	2003	124.06	136.70	140.52	137.18	163.63	117.16	122.18	114.27	106.82	102.43	92.37	85.58	120.24
265	MIDSTATE ELECTRIC COOPERA	361		BASE	TBL load forecast	2002	52.04	55.36	59.57	58.21	61.06	53.05	44.61	55.40	40.30	45.75	43.51	43.83	51.06
266	MIDSTATE ELECTRIC COOPERA	361		LS	TBL load forecast	2002	52.04	55.36	59.57	58.21	61.06	53.05	44.61	55.40	40.30	45.75	43.51	43.83	51.06
267	MIDSTATE ELECTRIC COOPERA	361		BASE	TBL load forecast	2003	53.28	56.68	60.99	59.59	62.52	54.31	45.67	56.72	41.25	46.84	44.55	44.88	52.27
268	MIDSTATE ELECTRIC COOPERA	361		LS	TBL load forecast	2003	53.28	56.68	60.99	59.59	62.52	54.31	45.67	56.72	41.25	46.84	44.55	44.88	52.27
269	MILTON, TOWN OF	158		BASE	TBL load forecast	2002	8.99	10.12	11.80	11.83	11.93	9.71	7.99	6.38	5.59	5.74	5.47	5.71	8.44
270	MILTON, TOWN OF	158		LS	TBL load forecast	2002	8.99	10.12	11.80	11.83	11.93	9.71	7.99	6.38	5.59	5.74	5.47	5.71	8.44
271	MILTON, TOWN OF	158		BASE	TBL load forecast	2003	9.05	10.19	11.87	11.90	12.00	9.77	8.04	6.42	5.62	5.77	5.51	5.74	8.49
272	MILTON, TOWN OF	158		LS	TBL load forecast	2003	9.05	10.19	11.87	11.90	12.00	9.77	8.04	6.42	5.62	5.77	5.51	5.74	8.49
273	MILTON-FREEWATER, CITY OF	159		BASE	TBL load forecast	2002	10.58	11.96	16.16	18.47	21.52	12.19	6.66	5.30	4.34	9.13	10.90	7.50	11.23
274	MILTON-FREEWATER, CITY OF	159		LS	TBL load forecast	2002	19.11	20.49	24.69	27.00	30.05	20.72	15.17	13.81	12.85	17.64	19.41	16.01	19.75
275	MILTON-FREEWATER, CITY OF	159		BASE	TBL load forecast	2003	10.99	12.40	16.68	19.05	22.15	12.63	7.08	5.69	4.72	9.60	11.41	7.94	11.70
276	MILTON-FREEWATER, CITY OF	159		LS	TBL load forecast	2003	19.50	20.91	25.19	27.56	30.66	21.14	15.48	14.09	13.12	18.00	19.81	16.34	20.15
277	MINIDOKA, CITY OF	161		BASE	TBL load forecast	2002	0.11	0.12	0.15	0.16	0.14	0.10	0.08	0.05	0.07	0.08	0.08	0.08	0.10
278	MINIDOKA, CITY OF	161		LS	TBL load forecast	2002	0.11	0.12	0.15	0.16	0.14	0.10	0.08	0.05	0.07	0.08	0.08	0.08	0.10
279	MINIDOKA, CITY OF	161		BASE	TBL load forecast	2003	0.11	0.12	0.15	0.16	0.14	0.10	0.09	0.05	0.07	0.08	0.08	0.08	0.10
280	MINIDOKA, CITY OF	161		LS	TBL load forecast	2003	0.11	0.12	0.15	0.16	0.14	0.10	0.09	0.05	0.07	0.08	0.08	0.08	0.10
281	MISSOULA ELECTRIC COOPERA	364		BASE	TBL load forecast	2002	22.38	26.18	29.57	30.87	33.01	25.82	20.88	19.52	18.04	19.56	19.29	16.45	23.46
282	MISSOULA ELECTRIC COOPERA	364		LS	TBL load forecast	2002	22.55	26.35	29.74	31.04	33.18	25.99	21.03	19.67	18.19	19.71	19.44	16.60	23.62
283	MISSOULA ELECTRIC COOPERA	364		BASE	TBL load forecast	2003	22.81	26.68	30.14	31.46	33.64	26.32	21.42	20.03	18.52	20.08	19.80	16.91	23.98
284	MISSOULA ELECTRIC COOPERA	364		LS	TBL load forecast	2003	22.96	26.83	30.29	31.61	33.79	26.47	21.42	20.03	18.52	20.08	19.80	16.91	24.06
285	MODERN ELECTRIC WATER COM	366		BASE	TBL load forecast	2002	46.13	52.62	59.05	54.78	59.29	48.92	45.72	42.53	45.41	50.05	54.19	44.77	50.29
286	MODERN ELECTRIC WATER COM	366		LS	TBL load forecast	2002	46.10	52.60	59.10	54.80	59.30	48.90	45.70	42.50	45.40	50.10	54.20	44.80	50.29
287	MODERN ELECTRIC WATER COM	366		BASE	TBL load forecast	2003	47.75	54.46	61.11	56.69	61.37	50.63	47.32	44.01	47.00	51.80	56.08	46.34	52.05
288	MODERN ELECTRIC WATER COM	366		LS	TBL load forecast	2003	47.75	54.46	61.11	56.69	61.37	50.63	47.32	44.01	47.00	51.80	56.08	46.34	52.05
289	MONMOUTH, CITY OF	163		BASE	TBL load forecast	2002	11.61	12.12	14.47	15.31	17.17	12.08	10.79	8.71	6.88	7.14	7.12	7.09	10.87
290	MONMOUTH, CITY OF	163		LS	TBL load forecast	2002	11.61	12.12	14.47	15.31	17.17	12.08	10.79	8.71	6.88	7.14	7.12	7.09	10.87
291	MONMOUTH, CITY OF	163		BASE	TBL load forecast	2003	11.70	12.22	14.59	15.43	17.31	12.17	10.88	8.79	6.93	7.20	7.18	7.15	10.96

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
292	MONMOUTH, CITY OF	163		LS	TBL load forecast	2003	11.70	12.22	14.59	15.43	17.31	12.17	10.88	8.79	6.93	7.20	7.18	7.15	10.96
293	NESPELEM VALLEY ELECTRIC	367		BASE	TBL load forecast	2002	6.23	6.04	7.44	8.51	8.41	6.48	5.96	5.41	6.33	6.64	7.74	6.12	6.78
294	NESPELEM VALLEY ELECTRIC	367		LS	TBL load forecast	2002	6.32	6.13	7.53	8.60	8.50	6.57	6.04	5.49	6.41	6.72	7.82	6.20	6.86
295	NESPELEM VALLEY ELECTRIC	367		BASE	TBL load forecast	2003	6.31	6.11	7.53	8.61	8.51	6.56	6.10	5.55	6.48	6.79	7.91	6.27	6.89
296	NESPELEM VALLEY ELECTRIC	367		LS	TBL load forecast	2003	6.39	6.19	7.61	8.69	8.59	6.64	6.10	5.55	6.48	6.79	7.91	6.27	6.93
297	NORTHERN LIGHTS INC	370	PNGC	BASE	TBL load forecast	2002	33.07	37.11	44.17	42.73	46.58	38.83	32.75	27.05	23.64	24.23	23.24	21.04	32.87
298	NORTHERN LIGHTS INC	370	PNGC	LS	TBL load forecast	2002	33.66	37.70	44.76	43.32	47.17	39.42	33.28	27.58	24.17	24.76	23.77	21.57	33.43
299	NORTHERN LIGHTS INC	370	PNGC	BASE	TBL load forecast	2003	33.37	37.44	44.55	43.10	46.98	39.17	33.51	27.78	24.34	24.94	23.94	21.73	33.40
300	NORTHERN LIGHTS INC	370	PNGC	LS	TBL load forecast	2003	33.90	37.97	45.08	43.63	47.51	39.70	33.51	27.78	24.34	24.94	23.94	21.73	33.67
301	NORTHERN WASCO COUNTY PUD	262		BASE	TBL load forecast	2002	37.16	38.00	50.08	57.91	49.22	37.38	39.90	29.93	31.03	32.32	36.83	33.15	39.41
302	NORTHERN WASCO COUNTY PUD	262		LS	TBL load forecast	2002	37.16	38.00	50.08	57.91	49.22	37.38	39.90	29.93	31.03	32.32	36.83	33.15	39.41
303	NORTHERN WASCO COUNTY PUD	262		BASE	TBL load forecast	2003	37.31	38.15	50.28	58.14	49.41	37.53	40.06	30.05	31.16	32.45	36.97	33.28	39.57
304	NORTHERN WASCO COUNTY PUD	262		LS	TBL load forecast	2003	37.31	38.15	50.28	58.14	49.41	37.53	40.06	30.05	31.16	32.45	36.97	33.28	39.57
305	OHOP MUTUAL LIGHT COMPANY	372		BASE	TBL load forecast	2002	12.51	12.15	16.10	15.82	16.81	12.83	11.25	8.64	5.57	5.33	5.89	5.10	10.67
306	OHOP MUTUAL LIGHT COMPANY	372		LS	TBL load forecast	2002	12.51	12.15	16.10	15.82	16.81	12.83	11.25	8.64	5.57	5.33	5.89	5.10	10.67
307	OHOP MUTUAL LIGHT COMPANY	372		BASE	TBL load forecast	2003	12.73	12.37	16.40	16.11	17.11	13.07	11.46	8.80	5.67	5.43	6.00	5.19	10.86
308	OHOP MUTUAL LIGHT COMPANY	372		LS	TBL load forecast	2003	12.73	12.37	16.40	16.11	17.11	13.07	11.46	8.80	5.67	5.43	6.00	5.19	10.86
309	OKANOGAN COUNTY ELECTRIC	373		BASE	TBL load forecast	2002	7.20	7.41	9.50	10.86	10.41	7.08	5.67	4.90	4.06	4.57	5.04	4.52	6.77
310	OKANOGAN COUNTY ELECTRIC	373		LS	TBL load forecast	2002	7.20	7.40	9.50	10.90	10.40	7.10	5.70	4.90	4.10	4.60	5.00	4.50	6.77
311	OKANOGAN COUNTY ELECTRIC	373		BASE	TBL load forecast	2003	7.21	7.43	9.52	10.89	10.43	7.10	5.68	4.91	4.07	4.58	5.05	4.53	6.78
312	OKANOGAN COUNTY ELECTRIC	373		LS	TBL load forecast	2003	7.21	7.43	9.52	10.89	10.43	7.10	5.68	4.91	4.07	4.58	5.05	4.53	6.78
313	OKANOGAN COUNTY PUD NO 1	266		BASE	added 11 MW	2002	44.31	7.81	32.15	68.51	57.52	27.44	23.23	0.00	0.00	6.07	26.69	18.37	26.01
314	OKANOGAN COUNTY PUD NO 1	266		LS	added 11 MW	2002	100.49	84.58	119.23	132.00	117.22	107.49	95.49	76.80	74.45	58.25	76.01	80.07	93.51
315	OKANOGAN COUNTY PUD NO 1	266		BASE	added 11 MW	2003	45.07	8.16	32.58	69.01	57.98	28.19	23.99	0.00	0.00	6.40	27.13	19.00	26.46
316	OKANOGAN COUNTY PUD NO 1	266		LS	added 11 MW	2003	101.24	84.93	119.66	132.50	117.68	108.24	96.24	77.22	75.08	58.58	76.45	80.70	94.04
317	ORCAS POWER & LIGHT COOPE	376		BASE	TBL load forecast	2002	31.06	37.17	43.35	49.25	43.03	36.09	29.66	23.24	19.18	18.98	18.81	18.13	30.66
318	ORCAS POWER & LIGHT COOPE	376		LS	TBL load forecast	2002	31.10	37.20	43.40	49.30	43.00	36.10	29.70	23.20	19.20	19.00	18.80	18.10	30.68
319	ORCAS POWER & LIGHT COOPE	376		BASE	TBL load forecast	2003	31.57	37.78	44.06	50.06	43.74	36.68	30.15	23.63	19.50	19.29	19.12	18.43	31.17
320	ORCAS POWER & LIGHT COOPE	376		LS	TBL load forecast	2003	31.57	37.78	44.06	50.06	43.74	36.68	30.15	23.63	19.50	19.29	19.12	18.43	31.17
321	OREGON TRAIL COOPERATIVE	371	PNGC	BASE	TBL load forecast	2002	90.09	98.15	121.73	112.83	125.16	95.85	85.86	89.40	81.61	92.95	93.26	85.60	97.71
322	OREGON TRAIL COOPERATIVE	371	PNGC	LS	TBL load forecast	2002	90.09	98.15	121.73	112.83	125.16	95.85	85.86	89.40	81.61	92.95	93.26	85.60	97.71
323	OREGON TRAIL COOPERATIVE	371	PNGC	BASE	TBL load forecast	2003	90.59	98.69	122.41	113.46	125.86	96.38	86.33	89.89	82.06	93.46	93.77	86.08	98.25
324	OREGON TRAIL COOPERATIVE	371	PNGC	LS	TBL load forecast	2003	90.59	98.69	122.41	113.46	125.86	96.38	86.33	89.89	82.06	93.46	93.77	86.08	98.25
325	PACIFIC COUNTY PUD NO 2	270		BASE	TBL load forecast	2002	43.60	43.40	53.20	59.30	65.40	54.80	45.10	35.10	27.20	26.70	24.00	24.10	41.83
326	PACIFIC COUNTY PUD NO 2	270		LS	TBL load forecast	2002	43.60	43.40	53.20	59.30	65.40	54.80	45.10	35.10	27.20	26.70	24.00	24.10	41.83
327	PACIFIC COUNTY PUD NO 2	270		BASE	TBL load forecast	2003	44.09	43.88	53.86	60.06	66.17	55.43	45.66	35.52	27.57	27.06	24.33	24.41	42.34
328	PACIFIC COUNTY PUD NO 2	270		LS	TBL load forecast	2003	44.09	43.88	53.86	60.06	66.17	55.43	45.66	35.52	27.57	27.06	24.33	24.41	42.34
329	PARKLAND LIGHT & POWER CO	375		BASE	TBL load forecast	2002	18.78	18.98	24.28	25.64	25.09	19.01	17.49	14.28	11.16	11.19	11.11	10.92	17.33
330	PARKLAND LIGHT & POWER CO	375		LS	TBL load forecast	2002	18.78	18.98	24.28	25.64	25.09	19.01	17.49	14.28	11.16	11.19	11.11	10.92	17.33
331	PARKLAND LIGHT & POWER CO	375		BASE	TBL load forecast	2003	19.19	19.39	24.80	26.20	25.64	19.42	17.87	14.59	11.40	11.43	11.35	11.16	17.70
332	PARKLAND LIGHT & POWER CO	375		LS	TBL load forecast	2003	19.19	19.39	24.80	26.20	25.64	19.42	17.87	14.59	11.40	11.43	11.35	11.16	17.70

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
333	PEND OREILLE COUNTY PUD N	273		BASE	OY99 NWPP Op Pgm	2002	121.67	103.06	104.14	110.29	80.03	61.32	84.23	96.97	120.13	108.62	106.75	86.52	98.64
334	PEND OREILLE COUNTY PUD N	273		LS	OY99 NWPP Op Pgm	2002	121.97	103.36	104.44	110.59	80.33	61.72	84.63	97.37	120.53	108.92	107.05	86.82	98.98
335	PEND OREILLE COUNTY PUD N	273		BASE	OY99 NWPP Op Pgm	2003	122.34	103.74	104.83	110.37	80.29	61.52	84.70	97.80	121.11	109.61	106.82	86.54	99.14
336	PEND OREILLE COUNTY PUD N	273		LS	OY99 NWPP Op Pgm	2003	122.60	104.00	105.10	110.70	80.60	61.90	85.10	98.20	121.50	109.90	107.10	86.80	99.46
337	PENINSULA LIGHT COMPANY,	374		BASE	TBL load forecast	2002	87.35	96.44	121.09	122.67	112.35	97.18	79.19	65.78	50.02	45.61	47.62	49.54	81.24
338	PENINSULA LIGHT COMPANY,	374		LS	TBL load forecast	2002	87.35	96.44	121.09	122.67	112.35	97.18	79.19	65.78	50.02	45.61	47.62	49.54	81.24
339	PENINSULA LIGHT COMPANY,	374		BASE	TBL load forecast	2003	87.97	97.13	121.95	123.54	113.15	97.87	79.75	66.25	50.37	45.93	47.96	49.89	81.81
340	PENINSULA LIGHT COMPANY,	374		LS	TBL load forecast	2003	87.97	97.13	121.95	123.54	113.15	97.87	79.75	66.25	50.37	45.93	47.96	49.89	81.81
341	PLUMMER, CITY OF	167		BASE	TBL load forecast	2002	4.32	3.68	4.90	4.85	4.79	3.16	3.42	2.95	2.56	2.57	2.43	2.93	3.55
342	PLUMMER, CITY OF	167		LS	TBL load forecast	2002	4.32	3.68	4.90	4.85	4.79	3.16	3.42	2.95	2.56	2.57	2.43	2.93	3.55
343	PLUMMER, CITY OF	167		BASE	TBL load forecast	2003	4.40	3.70	4.90	4.90	4.80	3.20	3.40	3.00	2.60	2.60	2.40	2.90	3.57
344	PLUMMER, CITY OF	167		LS	TBL load forecast	2003	4.35	3.70	4.93	4.88	4.81	3.17	3.44	2.97	2.58	2.58	2.44	2.94	3.57
345	PORT ANGELES, CITY OF, LI	170		BASE	TBL load forecast	2002	75.16	83.65	72.29	95.79	106.70	70.56	55.55	50.76	47.17	49.30	54.13	65.20	68.86
346	PORT ANGELES, CITY OF, LI	170		LS	TBL load forecast	2002	76.10	84.59	73.23	96.73	107.64	71.50	56.39	51.60	48.01	50.14	54.97	66.04	69.75
347	PORT ANGELES, CITY OF, LI	170		BASE	TBL load forecast	2003	76.03	84.59	73.13	96.85	107.87	71.38	56.96	52.11	48.49	50.64	55.52	66.70	70.02
348	PORT ANGELES, CITY OF, LI	170		LS	TBL load forecast	2003	76.87	85.43	73.97	97.69	108.71	72.22	56.96	52.11	48.49	50.64	55.52	66.70	70.44
349	PORT TOWNSEND PAPER CORPO	716		BASE	12/98 White Book	2002	13.75	14.78	14.78	14.44	15.80	14.49	14.63	2.49	14.10	14.83	13.03	14.32	13.45
350	PORT TOWNSEND PAPER CORPO	716		LS	12/98 White Book	2002	13.75	14.78	14.78	14.44	15.80	14.49	14.63	2.49	14.10	14.83	13.03	14.32	13.45
351	PORT TOWNSEND PAPER CORPO	716		BASE	12/98 White Book	2003	13.83	14.88	14.88	14.45	15.85	14.54	14.71	2.51	14.21	14.97	13.04	14.32	13.52
352	PORT TOWNSEND PAPER CORPO	716		LS	12/98 White Book	2003	13.83	14.88	14.88	14.45	15.85	14.54	14.71	2.51	14.21	14.97	13.04	14.32	13.52
353	RAFT RIVER RURAL ELECTRIC	379	PNGC	BASE	TBL load forecast	2002	8.79	6.91	7.79	9.60	7.91	6.86	10.91	30.54	35.14	48.33	37.97	39.11	20.82
354	RAFT RIVER RURAL ELECTRIC	379	PNGC	LS	TBL load forecast	2002	8.80	6.90	7.80	9.60	7.90	6.90	10.90	30.50	35.10	48.30	38.00	39.10	20.82
355	RAFT RIVER RURAL ELECTRIC	379	PNGC	BASE	TBL load forecast	2003	8.84	6.95	7.84	9.65	7.96	6.90	10.97	30.71	35.34	48.60	38.18	39.32	20.94
356	RAFT RIVER RURAL ELECTRIC	379	PNGC	LS	TBL load forecast	2003	8.84	6.95	7.84	9.65	7.96	6.90	10.97	30.71	35.34	48.60	38.18	39.32	20.94
357	RAVALLI COUNTY ELECTRIC C	380		BASE	TBL load forecast	2002	18.61	19.62	24.46	24.62	23.87	20.30	16.55	15.85	13.49	15.46	15.39	12.72	18.41
358	RAVALLI COUNTY ELECTRIC C	380		LS	TBL load forecast	2002	18.80	19.80	24.60	24.80	24.00	20.50	16.70	16.00	13.60	15.60	15.50	12.90	18.57
359	RAVALLI COUNTY ELECTRIC C	380		BASE	TBL load forecast	2003	19.16	20.20	25.17	25.34	24.57	20.89	17.17	16.45	14.03	16.05	15.97	13.23	19.02
360	RAVALLI COUNTY ELECTRIC C	380		LS	TBL load forecast	2003	19.31	20.35	25.32	25.49	24.72	21.04	17.17	16.45	14.03	16.05	15.97	13.23	19.09
361	RICHLAND, CITY OF	175		BASE	TBL load forecast	2002	85.41	74.47	106.64	130.80	128.27	82.01	65.47	64.31	71.12	80.69	89.11	64.26	86.88
362	RICHLAND, CITY OF	175		LS	TBL load forecast	2002	102.76	91.82	123.99	148.15	145.62	99.36	82.68	81.52	88.33	97.90	106.32	81.47	104.16
363	RICHLAND, CITY OF	175		BASE	TBL load forecast	2003	86.93	75.84	108.44	132.93	130.36	83.48	67.79	66.61	73.52	83.21	91.75	66.56	88.95
364	RICHLAND, CITY OF	175		LS	TBL load forecast	2003	104.14	93.05	125.65	150.14	147.57	100.69	83.79	82.61	89.52	99.21	107.75	82.56	105.56
365	RIVERSIDE ELECTRIC COMPAN	381		BASE	TBL load forecast	2002	2.49	2.37	3.62	2.23	1.91	1.74	1.40	1.63	1.91	2.27	1.91	1.64	2.09
366	RIVERSIDE ELECTRIC COMPAN	381		LS	TBL load forecast	2002	2.50	2.40	3.60	2.20	1.90	1.70	1.40	1.60	1.90	2.30	1.90	1.60	2.08
367	RIVERSIDE ELECTRIC COMPAN	381		BASE	TBL load forecast	2003	2.50	2.38	3.63	2.24	1.91	1.74	1.41	1.64	1.92	2.28	1.92	1.64	2.10
368	RIVERSIDE ELECTRIC COMPAN	381		LS	TBL load forecast	2003	2.50	2.38	3.63	2.24	1.91	1.74	1.41	1.64	1.92	2.28	1.92	1.64	2.10
369	RUPERT, CITY OF	177		BASE	TBL load forecast	2002	25.34	29.55	33.79	28.71	27.30	22.12	24.24	21.71	18.93	21.25	20.66	10.45	23.67
370	RUPERT, CITY OF	177		LS	TBL load forecast	2002	25.34	29.55	33.79	28.71	27.30	22.12	24.24	21.71	18.93	21.25	20.66	10.45	23.67
371	RUPERT, CITY OF	177		BASE	TBL load forecast	2003	25.85	30.14	34.46	29.29	27.85	22.57	24.73	22.15	19.31	21.68	21.07	10.65	24.15
372	RUPERT, CITY OF	177		LS	TBL load forecast	2003	25.85	30.14	34.46	29.29	27.85	22.57	24.73	22.15	19.31	21.68	21.07	10.65	24.15
373	SALEM ELECTRIC COOPERATIV	383		BASE	TBL load forecast	2002	61.18	62.77	76.80	73.13	79.33	60.96	54.88	47.57	47.01	51.81	56.52	53.17	60.43

Appendix B
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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
374	SALEM ELECTRIC COOPERATIV	383		LS	TBL load forecast	2002	61.93	63.52	77.55	73.88	80.08	61.71	55.55	48.24	47.68	52.48	57.19	53.84	61.14
375	SALEM ELECTRIC COOPERATIV	383		BASE	TBL load forecast	2003	61.81	63.41	77.56	73.86	80.12	61.58	56.05	48.67	48.10	52.95	57.70	54.31	61.34
376	SALEM ELECTRIC COOPERATIV	383		LS	TBL load forecast	2003	62.50	64.10	78.20	74.50	80.80	62.30	56.10	48.70	48.10	53.00	57.70	54.30	61.69
377	SALMON RIVER ELECTRIC COO	384		BASE	TBL load forecast	2002	39.93	38.46	46.43	36.45	23.23	29.51	22.83	19.27	14.29	28.83	43.09	42.67	32.08
378	SALMON RIVER ELECTRIC COO	384		LS	TBL load forecast	2002	39.93	38.46	46.43	36.45	23.23	29.51	22.83	19.27	14.29	28.83	43.09	42.67	32.08
379	SALMON RIVER ELECTRIC COO	384		BASE	TBL load forecast	2003	40.53	39.04	47.13	37.00	23.58	29.95	23.18	19.56	14.51	29.27	43.74	43.31	32.57
380	SALMON RIVER ELECTRIC COO	384		LS	TBL load forecast	2003	40.53	39.04	47.13	37.00	23.58	29.95	23.18	19.56	14.51	29.27	43.74	43.31	32.57
381	SKAMANIA COUNTY PUD NO 1	279		BASE	TBL load forecast	2002	20.25	17.77	24.79	26.82	28.75	23.43	19.64	15.95	11.90	12.97	12.97	12.67	18.99
382	SKAMANIA COUNTY PUD NO 1	279		LS	TBL load forecast	2002	20.60	18.10	25.20	27.20	29.10	23.80	20.00	16.30	12.20	13.30	13.30	13.00	19.34
383	SKAMANIA COUNTY PUD NO 1	279		BASE	TBL load forecast	2003	20.59	18.08	25.20	27.27	29.22	23.82	20.27	16.52	12.42	13.50	13.49	13.20	19.47
384	SKAMANIA COUNTY PUD NO 1	279		LS	TBL load forecast	2003	20.92	18.41	25.53	27.60	29.55	24.15	20.27	16.52	12.42	13.50	13.49	13.20	19.63
385	SODA SPRINGS, CITY OF	181		BASE	TBL load forecast	2002	3.24	3.71	4.09	4.05	4.00	3.52	3.08	2.88	2.32	2.50	2.43	2.37	3.18
386	SODA SPRINGS, CITY OF	181		LS	TBL load forecast	2002	3.24	3.71	4.09	4.05	4.00	3.52	3.08	2.88	2.32	2.50	2.43	2.37	3.18
387	SODA SPRINGS, CITY OF	181		BASE	TBL load forecast	2003	3.25	3.71	4.10	4.05	4.00	3.53	3.09	2.88	2.32	2.50	2.44	2.37	3.19
388	SODA SPRINGS, CITY OF	181		LS	TBL load forecast	2003	3.25	3.71	4.10	4.05	4.00	3.53	3.09	2.88	2.32	2.50	2.44	2.37	3.19
389	SOUTH SIDE ELECTRIC LINES	385		BASE	TBL load forecast	2002	4.50	4.90	5.80	6.10	6.00	4.70	4.90	8.20	10.80	10.00	7.40	7.30	6.72
390	SOUTH SIDE ELECTRIC LINES	385		LS	TBL load forecast	2002	4.50	4.90	5.80	6.10	6.00	4.70	4.90	8.20	10.80	10.00	7.40	7.30	6.72
391	SOUTH SIDE ELECTRIC LINES	385		BASE	TBL load forecast	2003	4.55	4.99	5.92	6.19	6.16	4.80	5.04	8.33	11.05	10.19	7.56	7.41	6.85
392	SOUTH SIDE ELECTRIC LINES	385		LS	TBL load forecast	2003	4.55	4.99	5.92	6.19	6.16	4.80	5.04	8.33	11.05	10.19	7.56	7.41	6.85
393	STEILACOOM, TOWN OF	185		BASE	TBL load forecast	2002	7.41	7.15	9.97	9.17	8.82	6.50	5.19	3.73	2.59	2.57	2.64	3.33	5.76
394	STEILACOOM, TOWN OF	185		LS	TBL load forecast	2002	7.41	7.15	9.97	9.17	8.82	6.50	5.19	3.73	2.59	2.57	2.64	3.33	5.76
395	STEILACOOM, TOWN OF	185		BASE	TBL load forecast	2003	7.50	7.24	10.10	9.29	8.94	6.58	5.25	3.78	2.63	2.60	2.68	3.37	5.83
396	STEILACOOM, TOWN OF	185		LS	TBL load forecast	2003	7.50	7.24	10.10	9.29	8.94	6.58	5.25	3.78	2.63	2.60	2.68	3.37	5.83
397	SUMAS, CITY OF	186		BASE	TBL load forecast	2002	2.40	2.50	2.60	2.60	2.20	2.30	2.10	2.10	2.20	2.10	2.10	2.10	2.28
398	SUMAS, CITY OF	186		LS	TBL load forecast	2002	2.40	2.50	2.60	2.60	2.20	2.30	2.10	2.10	2.20	2.10	2.10	2.10	2.28
399	SUMAS, CITY OF	186		BASE	TBL load forecast	2003	2.35	2.54	2.58	2.65	2.17	2.26	2.09	2.14	2.24	2.13	2.11	2.06	2.28
400	SUMAS, CITY OF	186		LS	TBL load forecast	2003	2.35	2.54	2.58	2.65	2.17	2.26	2.09	2.14	2.24	2.13	2.11	2.06	2.28
401	SURPRISE VALLEY ELECTRIC	386		BASE	TBL load forecast	2002	19.81	18.09	21.70	18.28	17.89	16.71	14.29	15.32	17.77	26.34	27.22	27.44	20.07
402	SURPRISE VALLEY ELECTRIC	386		LS	TBL load forecast	2002	19.81	18.09	21.70	18.28	17.89	16.71	14.29	15.32	17.77	26.34	27.22	27.44	20.07
403	SURPRISE VALLEY ELECTRIC	386		BASE	TBL load forecast	2003	19.91	18.18	21.81	18.37	17.98	16.79	14.37	15.39	17.86	26.47	27.36	27.58	20.17
404	SURPRISE VALLEY ELECTRIC	386		LS	TBL load forecast	2003	19.91	18.18	21.81	18.37	17.98	16.79	14.37	15.39	17.86	26.47	27.36	27.58	20.17
405	TANNER ELECTRIC COOPERATI	387		BASE	TBL load forecast	2002	10.12	10.79	14.49	13.41	11.17	12.14	9.49	7.19	6.14	6.22	6.49	6.08	9.48
406	TANNER ELECTRIC COOPERATI	387		LS	TBL load forecast	2002	10.10	10.80	14.50	13.40	11.20	12.10	9.50	7.20	6.10	6.20	6.50	6.10	9.48
407	TANNER ELECTRIC COOPERATI	387		BASE	TBL load forecast	2003	10.60	11.30	15.10	14.00	11.70	12.70	9.90	7.50	6.40	6.50	6.80	6.40	9.91
408	TANNER ELECTRIC COOPERATI	387		LS	TBL load forecast	2003	10.57	11.27	15.14	14.01	11.67	12.68	9.92	7.51	6.42	6.50	6.78	6.35	9.90
409	TILLAMOOK COUNTY PUD	288		BASE	TBL load forecast	2002	64.52	64.37	91.89	89.55	96.99	82.71	66.54	55.36	44.90	44.37	43.95	38.91	65.34
410	TILLAMOOK COUNTY PUD	288		LS	TBL load forecast	2002	65.46	65.31	92.83	90.49	97.93	83.65	67.38	56.20	45.74	45.21	44.79	39.75	66.23
411	TILLAMOOK COUNTY PUD	288		BASE	TBL load forecast	2003	65.83	65.68	93.70	91.32	98.90	84.35	68.62	57.24	46.59	46.05	45.62	40.49	67.03
412	TILLAMOOK COUNTY PUD	288		LS	TBL load forecast	2003	66.67	66.52	94.54	92.16	99.74	85.19	68.62	57.24	46.59	46.05	45.62	40.49	67.45
413	TROY, CITY OF	189		BASE	TBL load forecast	2002	2.29	2.34	2.77	2.92	2.64	1.99	1.83	1.34	1.10	1.18	1.20	1.45	1.92
414	TROY, CITY OF	189		LS	TBL load forecast	2002	2.29	2.34	2.77	2.92	2.64	1.99	1.83	1.34	1.10	1.18	1.20	1.45	1.92
415	TROY, CITY OF	189		BASE	TBL load forecast	2003	2.30	2.35	2.78	2.94	2.65	2.01	1.84	1.35	1.11	1.19	1.21	1.46	1.93

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
416	TROY, CITY OF	189		LS	TBL load forecast	2003	2.30	2.35	2.78	2.94	2.65	2.01	1.84	1.35	1.11	1.19	1.21	1.46	1.93
417	U.S. AIR FORCE (FAIRCHILD	430		BASE	TBL load forecast	2002	9.50	10.38	10.67	11.22	11.15	10.25	9.95	9.64	10.24	11.05	11.68	10.46	10.52
418	U.S. AIR FORCE (FAIRCHILD	430		LS	TBL load forecast	2002	9.50	10.38	10.67	11.22	11.15	10.25	9.95	9.64	10.24	11.05	11.68	10.46	10.52
419	U.S. AIR FORCE (FAIRCHILD	430		BASE	TBL load forecast	2003	9.75	10.66	10.95	11.52	11.45	10.52	10.21	9.90	10.51	11.35	12.00	10.74	10.80
420	U.S. AIR FORCE (FAIRCHILD	430		LS	TBL load forecast	2003	9.75	10.66	10.95	11.52	11.45	10.52	10.21	9.90	10.51	11.35	12.00	10.74	10.80
421	U.S. DEPARTMENT OF NAVY (	451		BASE	TBL load forecast	2002	31.03	32.11	30.12	38.71	32.56	31.94	32.26	30.58	29.46	29.44	31.35	29.50	31.59
422	U.S. DEPARTMENT OF NAVY (	451		LS	TBL load forecast	2002	31.00	32.10	30.10	38.70	32.60	31.90	32.30	30.60	29.50	29.40	31.40	29.50	31.59
423	U.S. DEPARTMENT OF NAVY (	451		BASE	TBL load forecast	2003	31.48	32.58	30.56	39.27	33.04	32.40	32.74	31.03	29.89	29.87	31.81	29.93	32.05
424	U.S. DEPARTMENT OF NAVY (	451		LS	TBL load forecast	2003	31.50	32.60	30.60	39.30	33.00	32.40	32.70	31.00	29.90	29.90	31.80	29.90	32.05
425	U.S. DEPARTMENT OF NAVY (	490		BASE	TBL load forecast	2002	24.65	25.68	25.51	27.46	30.00	26.23	25.27	23.26	22.46	21.89	17.39	20.67	24.21
426	U.S. DEPARTMENT OF NAVY (	490		LS	TBL load forecast	2002	24.70	25.70	25.50	27.50	30.00	26.20	25.30	23.30	22.50	21.90	17.40	20.70	24.23
427	U.S. DEPARTMENT OF NAVY (	490		BASE	TBL load forecast	2003	24.94	25.99	25.81	27.78	30.35	26.54	25.56	23.53	22.73	22.14	17.60	20.91	24.49
428	U.S. DEPARTMENT OF NAVY (	490		LS	TBL load forecast	2003	24.90	26.00	25.80	27.80	30.40	26.50	25.60	23.50	22.70	22.10	17.60	20.90	24.48
429	U.S. DEPARTMENT OF NAVY (	491		BASE	TBL load forecast	2002	1.56	1.53	1.79	1.61	1.66	1.47	1.70	1.57	1.51	1.60	1.48	1.59	1.59
430	U.S. DEPARTMENT OF NAVY (	491		LS	TBL load forecast	2002	1.60	1.50	1.80	1.60	1.70	1.50	1.70	1.60	1.50	1.60	1.50	1.60	1.60
431	U.S. DEPARTMENT OF NAVY (	491		BASE	TBL load forecast	2003	1.60	1.57	1.84	1.65	1.70	1.50	1.74	1.61	1.55	1.64	1.51	1.63	1.63
432	U.S. DEPARTMENT OF NAVY (	491		LS	TBL load forecast	2003	1.60	1.60	1.80	1.70	1.70	1.50	1.70	1.60	1.60	1.60	1.50	1.60	1.63
433	UMATILLA ELECTRIC COOPERA	388	PNGC	BASE	TBL load forecast	2002	91.92	104.63	126.72	103.17	79.91	89.07	80.76	130.01	140.58	151.93	162.09	122.50	115.27
434	UMATILLA ELECTRIC COOPERA	388	PNGC	LS	TBL load forecast	2002	91.90	104.60	126.70	103.20	79.90	89.10	80.80	130.00	140.60	151.90	162.10	122.50	115.28
435	UMATILLA ELECTRIC COOPERA	388	PNGC	BASE	TBL load forecast	2003	93.88	106.86	129.42	105.37	81.62	90.97	82.48	132.79	143.58	155.17	165.55	125.11	117.73
436	UMATILLA ELECTRIC COOPERA	388	PNGC	LS	TBL load forecast	2003	93.90	106.90	129.40	105.40	81.60	91.00	82.50	132.80	143.60	155.20	165.60	125.10	117.75
437	UNITED ELECTRIC COOP	311		BASE	TBL load forecast	2002	24.45	22.67	31.49	32.21	31.08	24.29	21.03	22.23	27.17	33.60	28.45	27.70	27.20
438	UNITED ELECTRIC COOP	311		LS	TBL load forecast	2002	24.50	22.70	31.50	32.20	31.10	24.30	21.00	22.20	27.20	33.60	28.50	27.70	27.21
439	UNITED ELECTRIC COOP	311		BASE	TBL load forecast	2003	25.36	23.52	32.66	33.41	32.23	25.20	21.81	23.06	28.18	34.85	29.51	28.73	28.21
440	UNITED ELECTRIC COOP	311		LS	TBL load forecast	2003	25.40	23.50	32.70	33.40	32.20	25.20	21.80	23.10	28.20	34.90	29.50	28.70	28.22
441	US BUREAU OF MINES	410		BASE	TBL load forecast	2002	0.72	0.62	0.91	1.14	1.13	0.76	0.66	0.52	0.31	0.36	0.34	0.29	0.65
442	US BUREAU OF MINES	410		LS	TBL load forecast	2002	0.70	0.60	0.90	1.10	1.10	0.80	0.70	0.50	0.30	0.40	0.30	0.30	0.64
443	US BUREAU OF MINES	410		BASE	TBL load forecast	2003	0.73	0.63	0.92	1.16	1.14	0.76	0.66	0.53	0.31	0.37	0.34	0.30	0.65
444	US BUREAU OF MINES	410		LS	TBL load forecast	2003	0.70	0.60	0.90	1.20	1.10	0.80	0.70	0.50	0.30	0.40	0.30	0.30	0.65
445	US DEPT OF ENERGY (300 AR	405		BASE	TBL load forecast	2002	35.36	34.95	42.19	44.42	42.83	37.58	35.54	31.15	30.34	36.36	39.10	36.59	37.20
446	US DEPT OF ENERGY (300 AR	405		LS	TBL load forecast	2002	35.40	35.00	42.20	44.40	42.80	37.60	35.50	31.20	30.30	36.40	39.10	36.60	37.21
447	US DEPT OF ENERGY (300 AR	405		BASE	TBL load forecast	2003	35.54	35.13	42.40	44.65	43.04	37.77	35.72	31.31	30.49	36.55	39.29	36.78	37.39
448	US DEPT OF ENERGY (300 AR	405		LS	TBL load forecast	2003	35.50	35.10	42.40	44.70	43.00	37.80	35.70	31.30	30.50	36.60	39.30	36.80	37.39
449	US DEPT OF ENERGY (RICHLA	404		BASE	TBL load forecast	2002	60.33	64.60	67.00	78.44	72.37	29.45	29.82	27.18	-4.36	40.81	36.64	28.24	44.21
450	US DEPT OF ENERGY (RICHLA	404		LS	TBL load forecast	2002	71.20	75.00	83.70	84.20	85.40	32.30	40.00	46.80	32.10	37.30	2.40	31.30	51.81
451	US DEPT OF ENERGY (RICHLA	404		BASE	TBL load forecast	2003	60.66	65.03	67.44	78.50	72.60	29.55	29.99	27.41	-4.39	41.18	36.66	28.25	44.41
452	US DEPT OF ENERGY (RICHLA	404		LS	TBL load forecast	2003	71.60	75.50	84.20	84.20	85.70	32.40	40.20	47.20	32.40	37.70	2.40	31.30	52.07
453	USBIA-MISSION VALLEY POWE	483		BASE	TBL load forecast	2002	40.71	47.62	57.41	59.02	59.11	48.52	42.64	40.59	34.38	38.23	40.42	36.61	45.44
454	USBIA-MISSION VALLEY POWE	483		LS	TBL load forecast	2002	40.70	47.60	57.40	59.00	59.10	48.50	42.60	40.60	34.40	38.20	40.40	36.60	45.43
455	USBIA-MISSION VALLEY POWE	483		BASE	TBL load forecast	2003	41.20	48.19	58.10	59.73	59.82	49.10	43.16	41.07	34.79	38.69	40.91	37.05	45.98
456	USBIA-MISSION VALLEY POWE	483		LS	TBL load forecast	2003	41.20	48.20	58.10	59.70	59.80	49.10	43.20	41.10	34.80	38.70	40.90	37.10	45.99

Appendix B

NT Base and Load Shaping Sales
FY 2002 and FY 2003
(CP MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
457	USBR, YAKIMA PROJECT (ROZ	472		BASE	TBL load forecast	2002	6.70	1.22	5.92	7.80	14.39	15.42	12.89	12.96	9.82	9.41	8.59	11.63	9.73
458	USBR, YAKIMA PROJECT (ROZ	472		LS	TBL load forecast	2002	6.70	1.22	5.92	7.80	14.39	15.42	12.89	12.96	9.82	9.41	8.59	11.63	9.73
459	USBR, YAKIMA PROJECT (ROZ	472		BASE	TBL load forecast	2003	6.79	1.24	6.00	7.91	14.59	15.63	13.06	13.13	9.95	9.54	8.71	11.78	9.86
460	USBR, YAKIMA PROJECT (ROZ	472		LS	TBL load forecast	2003	6.79	1.24	6.00	7.91	14.59	15.63	13.06	13.13	9.95	9.54	8.71	11.78	9.86
461	VERA IRRIGATION DISTRICT	191		BASE	TBL load forecast	2002	32.65	36.71	41.45	45.50	45.08	35.89	29.94	29.59	22.74	24.58	25.41	24.10	32.80
462	VERA IRRIGATION DISTRICT	191		LS	TBL load forecast	2002	33.03	37.09	41.83	45.88	45.46	36.27	30.28	29.93	23.08	24.92	25.75	24.44	33.16
463	VERA IRRIGATION DISTRICT	191		BASE	TBL load forecast	2003	32.87	36.95	41.72	45.79	45.37	36.13	30.44	30.10	23.20	25.06	25.89	24.57	33.17
464	VERA IRRIGATION DISTRICT	191		LS	TBL load forecast	2003	33.21	37.29	42.06	46.13	45.71	36.47	30.44	30.10	23.20	25.06	25.89	24.57	33.34
465	VIGILANTE ELECTRIC COOPER	390		BASE	TBL load forecast	2002	17.97	19.32	24.98	19.44	19.44	16.19	12.38	16.98	21.86	27.54	24.46	17.21	19.81
466	VIGILANTE ELECTRIC COOPER	390		LS	TBL load forecast	2002	17.97	19.32	24.98	19.44	19.44	16.19	12.38	16.98	21.86	27.54	24.46	17.21	19.81
467	VIGILANTE ELECTRIC COOPER	390		BASE	TBL load forecast	2003	18.04	19.39	25.07	19.51	19.51	16.25	12.42	17.05	21.94	27.64	24.55	17.27	19.89
468	VIGILANTE ELECTRIC COOPER	390		LS	TBL load forecast	2003	18.04	19.39	25.07	19.51	19.51	16.25	12.42	17.05	21.94	27.64	24.55	17.27	19.89
469	WAHKIAKUM COUNTY PUD NO 1	293		BASE	TBL load forecast	2002	7.04	7.72	9.37	9.86	10.01	8.32	6.75	5.21	4.05	3.87	3.73	3.86	6.65
470	WAHKIAKUM COUNTY PUD NO 1	293		LS	TBL load forecast	2002	7.00	7.70	9.40	9.90	10.00	8.30	6.80	5.20	4.10	3.90	3.70	3.90	6.66
471	WAHKIAKUM COUNTY PUD NO 1	293		BASE	TBL load forecast	2003	7.18	7.87	9.55	10.05	10.20	8.48	6.88	5.31	4.13	3.94	3.80	3.93	6.78
472	WAHKIAKUM COUNTY PUD NO 1	293		LS	TBL load forecast	2003	7.20	7.90	9.60	10.10	10.20	8.50	6.90	5.30	4.10	3.90	3.80	3.90	6.78
473	WASCO ELECTRIC COOPERATIV	394		BASE	TBL load forecast	2002	13.33	12.47	16.29	15.88	15.60	13.10	10.93	10.17	9.07	11.37	11.74	10.10	12.50
474	WASCO ELECTRIC COOPERATIV	394		LS	TBL load forecast	2002	13.30	12.50	16.30	15.90	15.60	13.10	10.90	10.20	9.10	11.40	11.70	10.10	12.51
475	WASCO ELECTRIC COOPERATIV	394		BASE	TBL load forecast	2003	13.43	12.56	16.41	16.00	15.72	13.20	11.02	10.25	9.14	11.46	11.83	10.18	12.60
476	WASCO ELECTRIC COOPERATIV	394		LS	TBL load forecast	2003	13.40	12.60	16.40	16.00	15.70	13.20	11.00	10.30	9.10	11.50	11.80	10.20	12.60
477	WASHINGTON PUBLIC POWER S	195		BASE	TBL load forecast	2002	4.38	3.93	5.43	5.45	5.31	4.28	4.02	3.25	3.05	3.81	3.84	3.55	4.19
478	WASHINGTON PUBLIC POWER S	195		LS	TBL load forecast	2002	4.40	3.90	5.40	5.50	5.30	4.30	4.00	3.30	3.10	3.80	3.80	3.60	4.20
479	WASHINGTON PUBLIC POWER S	195		BASE	TBL load forecast	2003	4.40	3.95	5.46	5.48	5.33	4.30	4.04	3.27	3.07	3.83	3.86	3.57	4.21
480	WASHINGTON PUBLIC POWER S	195		LS	TBL load forecast	2003	4.40	4.00	5.50	5.50	5.30	4.30	4.00	3.30	3.10	3.80	3.90	3.60	4.23
481	WELLS RURAL ELECTRIC COOP	396		BASE	TBL load forecast	2002	85.53	88.37	86.03	88.51	93.39	76.23	81.89	90.84	79.53	77.23	79.76	87.96	84.61
482	WELLS RURAL ELECTRIC COOP	396		LS	TBL load forecast	2002	85.50	88.40	86.00	88.50	93.40	76.20	81.90	90.80	79.50	77.20	79.80	88.00	84.60
483	WELLS RURAL ELECTRIC COOP	396		BASE	TBL load forecast	2003	85.96	88.81	86.46	88.95	93.86	76.62	82.30	91.30	79.93	77.62	80.16	88.40	85.03
484	WELLS RURAL ELECTRIC COOP	396		LS	TBL load forecast	2003	86.00	88.80	86.50	89.00	93.90	76.60	82.30	91.30	79.90	77.60	80.20	88.40	85.04
485	WEST OREGON ELECTRIC COOP	397		BASE	TBL load forecast	2002	13.91	18.35	18.97	19.69	17.95	13.82	14.40	10.58	8.46	9.53	9.42	10.04	13.76
486	WEST OREGON ELECTRIC COOP	397		LS	TBL load forecast	2002	13.90	18.40	19.00	19.70	18.00	13.80	14.40	10.60	8.50	9.50	9.40	10.00	13.77
487	WEST OREGON ELECTRIC COOP	397		BASE	TBL load forecast	2003	14.22	18.76	19.39	20.12	18.35	14.13	14.72	10.82	8.65	9.74	9.63	10.27	14.07
488	WEST OREGON ELECTRIC COOP	397		LS	TBL load forecast	2003	14.20	18.80	19.40	20.10	18.40	14.10	14.70	10.80	8.70	9.70	9.60	10.30	14.07
489	WHATCOM COUNTY PUD NO 1	298		BASE	TBL load forecast	2002	73.26	60.81	73.92	71.56	75.31	56.60	62.87	73.79	63.21	73.22	64.99	74.43	68.66
490	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2002	73.30	60.80	73.90	71.60	75.30	56.60	62.90	73.80	63.20	73.20	65.00	74.40	68.67
491	WHATCOM COUNTY PUD NO 1	298		BASE	TBL load forecast	2003	63.50	61.02	74.16	71.88	75.56	56.77	63.10	74.03	63.44	73.46	65.25	74.68	68.07
492	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2003	63.50	61.00	74.20	71.90	75.60	56.80	63.10	74.00	63.40	73.50	65.30	74.70	68.08

APPENDIX C

Utility Delivery Billing Determinants

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

Line	Customer Name	Customer No.	Delivery Point No.	Delivery Point Name	kV	MW
1	Ashland, City Of	103	968	Mountain Avenue	12.5	8.76
2	Bandon, City Of	104	44	Bandon	12.5	6.34
3			386	Langlois	12.5	0.56
4			992	Two Mile Road	12.5	2.83
5						9.73
6	Benton REA	303	71	Blackrock	115.0	0.24
7			284	Grandview 12.5	12.5	3.59
8			418	Mabton	12.5	2.44
9			884	Rattle Snake	115.0	1.47
10			769	White Swan	12.5	3.81
11						11.55
12	Big Bend Electric	306	46	Baxter	13.8	5.22
13			175	Delight	24.9	0.83
14			195	Eagle Lake	13.8	6.13
15			216	Eltopia	13.8	3.30
16			272	Glade	13.8	5.03
17			310	Hatton	24.9	6.02
18			442	Mesa	13.8	6.09
19			562	Ralston	24.9	0.54
20			582	Ringold	13.8	3.55
21			586	Ritzville	24.9	4.01
22			621	Schrag	24.9	3.79
23			624	Scooteney 13.8 kV	13.8	2.80
24						47.33
25	Blachly-Lane Electric	309	754	Walton	12.5	0.96
26	Bureau of Mines	410	15	Albany	12.5	0.65
27	Cascade Locks, City Of	115	901	Acton	13.8	0.54
28			115	Cascade Locks	13.8	2.64
29						3.18
30	Central Electric Cooperative	312	298	Hampton	25.0	1.12
31	Central Lincoln PUD	207	263	Gardiner	13.8	22.08
32			425	Mapleton	12.5	3.89
33			572	Reedsport	12.5	10.33
34						36.30
35	Cheney, City Of	123	129	Cheney	13.8	12.55
36			253	Four Lakes	13.8	6.63
37						19.18
38	Clark PUD	216	103	Camas 12.5	12.5	27.32
39			107	Carborundum 12.5	12.5	22.69
40			127	Chelatchie 12.5	12.5	9.08
41			1351	Fishers Road 12.5	12.5	21.09
42			448	Mill Plain 12.5	12.5	18.54
43			1341	Van Ship 12.5	12.5	19.31
44						118.02
45	Clatskanie	219	134	Clatskanie	12.5	8.89
46	Clearwater Power	315	547	Potlatch	24.9	4.59
47	Columbia Basin Electric	318	342	Boardman (Ione)	12.5	14.16

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
48	Columbia Power	321	1334	Spray	24.9	0.70
49	Columbia REA	324	98	Burbank	13.8	2.28
50			661	Stateline	69.0	2.65
51			672	Sun Harbor	24.9	2.69
52			751	Walla Walla	12.5	4.39
53						12.02
54	Columbia River PUD	221	829	St. Helens 12.5	12.5	4.86
55	Consumers Power Inc.	327	100	Burnt Wood	25.0	1.65
56			260	Froman	115.0	5.87
57			460	Monmouth	12.5	1.91
58			489	North Butte	12.5	1.36
59			721	Tumble Creek	24.9	2.69
60						13.48
61	Coos-Curry Electric	330	43	Bandon	12.5	1.91
62			387	Langlois	12.5	1.44
63			492	Norway	12.5	2.36
64			543	Port Orford	12.5	4.16
65						9.87
66	Coulee Dam, City Of	125	158	Coulee Dam	12.0	2.99
67	Douglas Electric Coop.	333	187	Drain	12.5	2.73
68			264	Gardiner	13.8	0.50
69			573	Reedsport	12.5	0.66
70						3.90
71	Drain, City Of	128	186	Drain	12.5	4.00
72	Eatonville, Town Of	131	918	Lynch Creek	12.5	4.45
73	Flathead Electric	339	886	Haskell	24.9	2.39
74	Forest Grove, City Of	142	799	Filbert	12.5	10.43
75			247	Forest Grove	12.5	16.92
76			690	Thatcher Junction	12.5	11.51
77						38.86
78	Franklin PUD	233	581	Ringold	13.8	3.37
79	Grant County PUD	238	281	Grand Coulee #1	12.0	3.85
80	Hood River Electric	342	847	Hood River	12.5	1.31
81			520	Parkdale	12.5	6.17
82			782	Woody Guthrie	12.5	8.93
83						16.41
84	Idaho Co. L&P	345	285	East Grangeville	13.8	2.48

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
85	Inland Power & Light	348	125	Chambers	13.8	1.61
86			130	Cheney (Inland)	13.8	1.40
87			172	Deer Park	12.5	3.98
88			252	Four Lakes	13.8	3.42
89			262	Gaffney	12.5	0.49
90			300	Hangman	13.8	4.61
91			348	Jerita	12.5	0.73
92			390	Larene	12.5	1.65
93			431	Mayview	13.2	1.67
94			486	Newport	13.8	1.09
95			540	Pomeroy	12.5	0.53
96			583	Riparia	13.8	1.30
97						22.46
98	Lane Electric Cooperative	354	991	Hideaway	12.5	2.13
99	Lincoln Electric (mont.)	357	905	Stillwater	24.9	3.06
100			710	Trego	24.9	11.64
101						14.69
102	Lower Valley Power	360	519	Palisades	12.5	0.00
103			837	Swan Valley	12.5	1.32
104						1.32
105	Mason County PUD No. 1	257	191	Duckabush	12.5	2.81
106	Mason County PUD No. 3	258	545	Potlatch	12.5	2.27
107	Milton, City Of	158	674	Surprise Lake	12.5	8.46
108	Minidoka, City Of	161	451	Minidoka	2.4	0.10
109	Mission Valley Power	483	215	Elmo	12.5	2.06
110	Missoula Electric	364	137	Clinton	12.5	1.38
111			259	Frenchtown	12.5	6.27
112			337	Huson	13.8	3.12
113			683	Tarkio	12.5	0.58
114						11.36
115	Monmouth, City Of	163	459	Monmouth	12.5	10.92
116	Nespelem Valley Electric	367	400	Lone Pine	12.5	1.24
117	Northern Lights	370	79	Bonner's Ferry 13.8	13.8	2.42
118			377	Laclede	13.8	4.07
119			888	Moyie	13.8	0.93
120			891	North Bench	13.8	1.11
121			612	Samuels	13.8	2.52
122			614	Sandpoint	13.8	3.66
123			627	Selle	13.8	4.50
124			716	Troy	13.8	3.37
125			784	Yaak	12.5	0.49
126						23.06
127	Northern Wasco PUD	262	696	The Dalles 12.5	12.5	10.35
128	OHOP Mutual	372	736	Lynch Creek	12.5	3.62
129	Peninsula Light Company	374	903	Narrows	12.5	9.83

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
130	Ravalli Elec. Coop.	380	156	Corvallis	12.5	5.02
131			286	Grantsdale	12.5	1.81
132			666	Stevensville	12.5	3.99
133			740	Victor	12.5	3.25
134						14.08
135	Skamania County PUD	279	106	Cape Horn	12.5	3.29
136			113	Carson	12.5	7.33
137			80	North Bonneville	12.5	1.88
138			870	Stevenson	12.5	4.30
139			727	Underwood	12.5	2.68
140						19.49
141	Steilacoom, Town Of	185	663	Steilacoom	12.5	5.79
142	Surprise Valley	386	169	Davis Creek	12.5	0.49
143	Tillamook PUD	288	48	Beaver	12.5	2.36
144			265	Garibaldi	24.9	7.29
145			320	Hebo	20.8	0.84
146			457	Mohler	24.9	8.11
147			701	Tillamook 12.5	12.5	15.91
148			703	Tillamook 24.9	24.9	19.54
149						54.03
150	Troy, City Of	189	919	Troy	13.8	1.93
151	Wahkiakum County PUD	293	116	Cathlamet	12.5	5.67
152			676	Grays River	12.5	1.04
153						6.71
154	Wasco Electric	394	534	Pine Hollow	12.5	0.67
155			693	The Dalles	12.5	2.26
156			723	Tygh Valley	12.5	4.37
157						7.31
158	West Oregon Electric	397	478	Necanicum	12.5	0.49
159	Utility Delivery Billing Determinant					645.1

APPENDIX D

TBL Load Forecasting Methodology and Scope

Appendix D
TBL Load Forecasting Methodology and Scope

Load Analysis Methodology for Non-Generating Utilities

TBL's Load Forecasting Group prepared load projections for the 120 customers identified in Table 1a. Entities excluded from this analysis are shown in Table 1b, which are the Investor Owned Utilities (IOUs), Public Generating Utilities, and Direct Service Industries.

Load forecasts are determined by first extracting monthly metered raw load data from the Billing Information System (BIS) for the period January 1994 through December 1998. Annual growth rates for the utility's system requirements are then calculated for the period 1994 through 1998. This system-specific historical compound average annual growth rate (AARG) is then used to "grow" the system requirements (MWh) for the period (1999 – 2003). This assumes that near term future growth will not significantly depart from recent historical growth.

The historical data provides the basis for reviewing the varied loading patterns within a utility's distribution network. This gives the means by which the Point of Delivery (POD) shares of a utility's system requirements and monthly load shapes are determined. The derived values are then used to allocate projected monthly (MWh) loads by POD. It is assumed that monthly POD load profiles for a customer's system will emulate recent history.

Load factors (both historical POD and month specific) were used to estimate the non-coincidental demands in the forecast period. Load factor is defined as the monthly energy divided by (the maximum peak load * hours). Historical diversity factors are calculated for both coincident and "Total Transmission System Load" (TTSL) demands. For purposes here, "TTSL" demand is the demand at a POD at the time of the peak TTSL. Coincident demand is the POD's contribution to the customer's peak demand. The formulas used are:

1) Coincident MW divided by Non-Coincident MW = Coincident diversity factor
2) TTSL MW divided by Non-Coincident MW = TTSL diversity factor

These diversity factors are then applied to the estimated non-coincident demand to obtain projected coincident and TTSL demands.

Appendix D, Table 1a
Scope of Forecast
Customers Included in Forecast

	Name	No.
1	Albany Research Center *Bureau of Mines)	410
2	Albion, City of	102
3	Alder Mutual Light Company	301
4	Ashland, City of	103
5	Asotin PUD	201
6	Bandon, City of	104
7	Benton PUD	203
8	Benton REA	303
9	Big Bend Electric Coop.	306
10	Blachly-Lane County Coop. Electric	309
11	Blaine, City of	106
12	Bonners Ferry Electric, City of	107
13	Burley, City of	109
14	Canby Utility Board	111
15	Cascade Locks, City of	115
16	Central Electric Coop.	312
17	Central Lincoln PUD	207
18	Centralia, City of	119
19	Cheney, City of	123
20	Chewelah, City of	124
21	Clallam County PUD No. 1	213
22	Clatskanie PUD	219
23	Clearwater Power Company	315
24	Columbia Power Coop.	321
25	Columbia REA	324
26	Columbia River PUD	221
27	Columiba Basin Electric Coop.	318
28	Consolidated Irr. Dist #19	192
29	Consumers Power Inc.	327
30	Coos-Currry Electric Coop.	330
31	Coulee Dam Light Dept. City of	125
32	Declo, City of	127
33	Douglas Electric Coop. Inc.	333
34	Drain, City of	128
35	East End Mutual Electric	335
36	Eatonville, Town of	131
37	Ellensburg, City of	133
38	Elmhurst Mutual Power & Light Co.	334
39	Emerald PUD	229
40	Fairchild Air Base	430
41	Fall River Electric Coop.	337
42	Farmers Electric Co.	338
43	Ferry County PUD No. 1	230
44	Fircrest, City of	140
45	Flathead Electric Coop. Inc.	339
46	Forest Grove, City of	142
47	Franklin County PUD	233
48	Glacier Electric Coop. Inc.	340

Appendix D, Table 1a

Scope of Forecast
Customers Included in Forecast

	Name	No.
49	Harney Electric Coop.	341
50	Heyburn, City of	150
51	Hood River Electric Coop.	342
52	Idaho County Light and Power Coop.	345
53	Idaho Falls, City of	152
54	Inland Power & Light Company	348
55	Kittitas County PUD No. 1	246
56	Klickitat County PUD	250
57	Kootenai Electric Coop.	351
58	Lakeview Light & Power Company	353
59	Lane Electric Coop. Inc.	354
60	Lewis County PUD No. 1	253
61	Lincoln Electric Coop. (Mont.)	357
62	Lost River Electric Coop.	359
63	Lower Valley Power and Light	360
64	Mason County PUD No. 1	257
65	Mason County PUD No. 3	258
66	McCleary, City of	154
67	McMinnville, City of	155
68	Midstate Electric Coop.	361
69	Milton, City of	158
70	Milton-Freewater, City of	159
71	Minidoka, City of	161
72	Mission Valley Power	483
73	Missoula Electric Coop. Inc.	364
74	Modern Electric Water Company	366
75	Monmouth, City of	163
76	Nespelem Valley Coop.	367
77	Northern Lights Inc.	370
78	Northern Wasco County PUD	262
79	OHOP Mutual Light Company	372
80	Okanogan County Electric Coop.	373
81	Orcas Power & Light Company	376
82	Oregon Trail Consumers Coop.	371
83	Pacific County PUD No. 2	270
84	Parkland Light & Water Company	375
85	Peninsula Light Company Inc.	374
86	Plummer, City of	167
87	Port Angeles, City of	170
88	Raft River Elec. Coop.	379
89	Ravalli County Electric Coop.	380
90	Richland, City of	175
91	Riverside Electric Co.	381
92	Rupert, City of	177
93	Salem Electric	383
94	Salmon River Coop.	384
95	Skamania County PUD	279
96	Soda Spring, City of	181

Appendix D, Table 1a

Scope of Forecast
Customers Included in Forecast

	Name	No.
97	South Side Elec. Lines	385
98	Springfield Utility Board	184
99	Steilacoom, Town of	185
100	Sumas, City of	186
101	Surprise Valley Elec.	386
102	Tanner Electric Coop.	387
103	Tillamook PUD	288
104	Troy, City of	189
105	Umatilla Electric Coop.	388
106	United Electric Cooperative	311
107	US DOE Richland	405
108	US Navy - Bangor	490
109	US Navy - Jim Creek	491
110	US Navy - Puget Sound Naval Ship.	451
111	Vera Water and Power	191
112	Vigilante Electric Coop.	390
113	Wahkiakum County PUD	293
114	Wapato	482
115	Wasco Electric Coop.	394
116	Wells Rural Electric	396
117	West Oregon Electric Coop.	397
118	Whatcom County PUD No. 1	298
119	WPPSS (Energy Northwest)	195
120	Yakima Project (Roza)	472

Appendix D, Table 1b
Scope of Forecast
Excluded Customers

	Name	No.
121	ACPC, Inc.	701
122	Alcoa	605
123	Chelan County PUD No. 1	210
124	Clark Public Utilities	216
125	Columbia Falls Aluminum	615
126	Cowlitz County PUD	222
127	Douglas County PUD No. 1	226
128	Elf Atochem	702
129	Eugene Water and Electric Board	137
130	Georgia Pacific West Inc.	722
131	Glenbrook Nickel Joint Venture	725
132	Goldendale Aluminum (Col. Alum.)	614
133	Grant County PUD No. 2	238
134	Grays Harbor County PUD	241
135	Idaho Power Company	530
136	Intalco	640
137	Kaiser Aluminum	651
138	NW Aluminum Co.	635
139	Okanogan County PUD No. 1	266
140	Oregon Metallurigical	743
141	Oregon Steel Mill (Gilmore Steel)	785
142	Pacific Power and Light	560
143	Pend Oreille County PUD No. 1	273
144	Port Townsend Paper	716
145	Portland General Electric	575
146	Puget Sound Energy	580
147	Reynolds Metals Company	675
148	Seattle City Light	108
149	Snohomish County PUD No. 1	283
150	Tacoma Public Utilities	188
151	Vanalco	695
152	Washington Water Power	590

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Asotin County PUD	201	1998	10	NT	TRUE	0.080	0.080	0.076	0.076	0.000	0.000	0.156	0.156
Asotin County PUD	201	1998	11	NT	TRUE	0.083	0.083	0.079	0.079	0.000	0.000	0.086	0.086
Asotin County PUD	201	1998	12	NT	TRUE	0.003	0.003	0.003	0.003	0.000	0.000	0.058	0.058
Asotin County PUD	201	1999	1	NT	TRUE	0.002	0.002	0.002	0.002	0.000	0.000	0.004	0.004
Asotin County PUD	201	1999	2	NT	TRUE	0.001	0.001	0.002	0.002	0.000	0.000	0.037	0.037
Asotin County PUD	201	1999	3	NT	TRUE	0.082	0.082	0.001	0.001	0.000	0.000	0.082	0.082
Asotin County PUD	201	1999	4	NT	TRUE	0.099	0.099	0.095	0.095	0.000	0.000	0.099	0.099
Asotin County PUD	201	1999	5	NT	TRUE	0.101	0.101	0.127	0.127	0.000	0.000	0.101	0.101
Asotin County PUD	201	1999	6	NT	TRUE	0.082	0.082	0.458	0.458	0.000	0.000	0.082	0.082
Asotin County PUD	201	1999	7	NT	TRUE	0.837	0.837	0.689	0.689	0.000	0.000	0.837	0.837
Asotin County PUD	201	1999	8	NT	TRUE	0.816	0.816	1.333	1.333	0.000	0.000	0.816	0.816
Asotin County PUD	201	1999	9	NT	TRUE	0.816	0.816	1.482	1.482	0.000	0.000	0.816	0.816
Asotin County PUD	201	1999	10	NT	TRUE	0.241	0.241	0.080	0.080	0.000	0.000	0.165	0.165
Asotin County PUD	201	1999	11	NT	TRUE	0.095	0.095	0.084	0.084	0.000	0.000	0.092	0.092
Asotin County PUD	201	1999	12	NT	TRUE	0.113	0.113	0.003	0.003	0.000	0.000	0.058	0.058
Asotin County PUD	201	2000	1	NT	TRUE	0.005	0.005	0.002	0.002	0.000	0.000	0.004	0.004
Asotin County PUD	201	2000	2	NT	TRUE	0.072	0.072	0.002	0.002	0.000	0.000	0.037	0.037
Asotin County PUD	201	2000	3	NT	FALSE			0.001	0.001	0.000	0.000	0.082	0.082
Asotin County PUD	201	2000	4	NT	FALSE			0.091	0.091	0.000	0.000	0.095	0.095
Asotin County PUD	201	2000	5	NT	FALSE			0.111	0.111	0.000	0.000	0.088	0.088
Asotin County PUD	201	2000	6	NT	FALSE			0.462	0.462	0.000	0.000	0.083	0.083
Asotin County PUD	201	2000	7	NT	FALSE			0.696	0.696	0.000	0.000	0.846	0.846
Asotin County PUD	201	2000	8	NT	FALSE			1.293	1.293	0.000	0.000	0.792	0.792
Asotin County PUD	201	2000	9	NT	FALSE			1.412	1.412	0.000	0.000	0.777	0.777
Asotin County PUD	201	2000	10	NT	FALSE			0.081	0.081	0.000	0.000	0.167	0.167
Asotin County PUD	201	2000	11	NT	FALSE			0.084	0.084	0.000	0.000	0.092	0.092
Asotin County PUD	201	2000	12	NT	FALSE			0.003	0.003	0.000	0.000	0.058	0.058
Asotin County PUD	201	2001	1	NT	FALSE			0.002	0.002	0.000	0.000	0.004	0.004
Asotin County PUD	201	2001	2	NT	FALSE			0.002	0.002	0.000	0.000	0.037	0.037
Asotin County PUD	201	2001	3	NT	FALSE			0.001	0.001	0.000	0.000	0.082	0.082
Asotin County PUD	201	2001	4	NT	FALSE			0.083	0.083	0.000	0.000	0.086	0.086
Asotin County PUD	201	2001	5	NT	FALSE			0.104	0.104	0.000	0.000	0.083	0.083
Asotin County PUD	201	2001	6	NT	FALSE			0.423	0.423	0.000	0.000	0.076	0.076
Asotin County PUD	201	2001	7	NT	FALSE			0.739	0.739	0.000	0.000	0.898	0.898
Asotin County PUD	201	2001	8	NT	FALSE			1.362	1.362	0.000	0.000	0.834	0.834
Asotin County PUD	201	2001	9	NT	FALSE			1.412	1.412	0.000	0.000	0.777	0.777
Asotin County PUD	201	2001	10	NT	FALSE			0.081	0.081	0.000	0.000	0.081	0.081
Asotin County PUD	201	2001	11	NT	FALSE			0.085	0.085	0.000	0.000	0.085	0.085
Asotin County PUD	201	2001	12	NT	FALSE			0.003	0.003	0.000	0.000	0.003	0.003
Asotin County PUD	201	2002	1	NT	FALSE			0.002	0.002	0.000	0.000	0.002	0.002
Asotin County PUD	201	2002	2	NT	FALSE			0.002	0.002	0.000	0.000	0.002	0.002
Asotin County PUD	201	2002	3	NT	FALSE			0.001	0.001	0.000	0.000	0.001	0.001
Asotin County PUD	201	2002	4	NT	FALSE			0.084	0.084	0.000	0.000	0.084	0.084
Asotin County PUD	201	2002	5	NT	FALSE			0.104	0.104	0.000	0.000	0.104	0.104
Asotin County PUD	201	2002	6	NT	FALSE			0.427	0.427	0.000	0.000	0.427	0.427
Asotin County PUD	201	2002	7	NT	FALSE			0.746	0.746	0.000	0.000	0.746	0.746

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Asotin County PUD	201	2002	8	NT	FALSE			1.363	1.363	0.000	0.000	1.363	1.363
Asotin County PUD	201	2002	9	NT	FALSE			1.412	1.412	0.000	0.000	1.412	1.412
Asotin County PUD	201	2002	10	NT	FALSE			0.082	0.082	0.000	0.000	0.082	0.082
Asotin County PUD	201	2002	11	NT	FALSE			0.085	0.085	0.000	0.000	0.085	0.085
Asotin County PUD	201	2002	12	NT	FALSE			0.003	0.003	0.000	0.000	0.003	0.003
Asotin County PUD	201	2003	1	NT	FALSE			0.002	0.002	0.000	0.000	0.002	0.002
Asotin County PUD	201	2003	2	NT	FALSE			0.002	0.002	0.000	0.000	0.002	0.002
Asotin County PUD	201	2003	3	NT	FALSE			0.001	0.001	0.000	0.000	0.001	0.001
Asotin County PUD	201	2003	4	NT	FALSE			0.084	0.084	0.000	0.000	0.084	0.084
Asotin County PUD	201	2003	5	NT	FALSE			0.105	0.105	0.000	0.000	0.105	0.105
Asotin County PUD	201	2003	6	NT	FALSE			0.430	0.430	0.000	0.000	0.430	0.430
Asotin County PUD	201	2003	7	NT	FALSE			0.752	0.752	0.000	0.000	0.752	0.752
Asotin County PUD	201	2003	8	NT	FALSE			1.364	1.364	0.000	0.000	1.364	1.364
Asotin County PUD	201	2003	9	NT	FALSE			1.412	1.412	0.000	0.000	1.412	1.412
Bonners Ferry, City of	107	1998	10	NTP	TRUE	10.311	10.311						
Bonners Ferry, City of	107	1998	11	NTP	TRUE	9.951	11.031						
Bonners Ferry, City of	107	1998	12	NTP	TRUE	12.579	13.669						
Bonners Ferry, City of	107	1999	1	NTP	TRUE	10.770	11.001						
Bonners Ferry, City of	107	1999	2	NTP	TRUE	8.761	10.810						
Bonners Ferry, City of	107	1999	3	NTP	TRUE	7.701	9.681						
Bonners Ferry, City of	107	1999	4	NTP	TRUE	7.731	8.311						
Bonners Ferry, City of	107	1999	5	NTP	TRUE	7.381	8.653						
Bonners Ferry, City of	107	1999	6	NTP	TRUE	5.353	8.073						
Bonners Ferry, City of	107	1999	7	NTP	TRUE	5.523	6.633						
Bonners Ferry, City of	107	1999	8	NTP	TRUE	6.673	8.362						
Bonners Ferry, City of	107	1999	9	NTP	TRUE	8.233	11.121						
Bonners Ferry, City of	107	1999	10	NTP	TRUE	8.592	11.011						
Bonners Ferry, City of	107	1999	11	NTP	TRUE	10.061	11.131						
Bonners Ferry, City of	107	1999	12	NTP	TRUE	8.891	11.060						
Bonners Ferry, City of	107	2000	1	NTP	TRUE	10.150	12.900						
Bonners Ferry, City of	107	2000	2	NTP	TRUE	11.560	11.751						
Bonners Ferry, City of	107	2000	3	NTP	FALSE			8.445	8.445	0.000		6.718	8.445
Bonners Ferry, City of	107	2000	4	NTP	FALSE			7.268	5.885	0.000		5.474	7.268
Bonners Ferry, City of	107	2000	5	NTP	FALSE			6.981	3.139	0.000		2.678	6.981
Bonners Ferry, City of	107	2000	6	NTP	FALSE			7.399	3.280	0.000		2.175	7.399
Bonners Ferry, City of	107	2000	7	NTP	FALSE			7.046	3.147	0.000		2.621	7.046
Bonners Ferry, City of	107	2000	8	NTP	FALSE			8.539	7.928	0.000		6.327	8.539
Bonners Ferry, City of	107	2000	9	NTP	FALSE			10.594	7.336	0.000		5.431	10.594
Bonners Ferry, City of	107	2000	10	NTP	FALSE			22.047	22.528	0.000		20.036	22.047
Bonners Ferry, City of	107	2000	11	NTP	FALSE			22.967	21.757	0.000		19.646	22.967
Bonners Ferry, City of	107	2000	12	NTP	FALSE			23.720	22.021	0.000		19.059	23.720
Bonners Ferry, City of	107	2001	1	NTP	FALSE			24.506	23.710	0.000		20.811	24.506
Bonners Ferry, City of	107	2001	2	NTP	FALSE			24.204	23.355	0.000		21.122	24.204
Bonners Ferry, City of	107	2001	3	NTP	FALSE			8.472	8.472	0.000		6.740	8.472
Bonners Ferry, City of	107	2001	4	NTP	FALSE			7.309	5.918	0.000		5.505	7.309
Bonners Ferry, City of	107	2001	5	NTP	FALSE			7.040	3.166	0.000		2.700	7.040

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Bonners Ferry, City of	107	2001	6	NTP	FALSE			7.459	3.307	0.000		2.193	7.459
Bonners Ferry, City of	107	2001	7	NTP	FALSE			7.110	3.176	0.000		2.644	7.110
Bonners Ferry, City of	107	2001	8	NTP	FALSE			8.544	7.933	0.000		6.331	8.544
Bonners Ferry, City of	107	2001	9	NTP	FALSE			10.596	7.338	0.000		5.432	10.596
Bonners Ferry, City of	107	2001	10	NT	FALSE			22.169	22.653	0.000		20.147	22.169
Bonners Ferry, City of	107	2001	11	NT	FALSE			23.118	21.900	0.000		19.775	23.118
Bonners Ferry, City of	107	2001	12	NT	FALSE			23.877	22.167	0.000		19.185	23.877
Bonners Ferry, City of	107	2002	1	NT	FALSE			24.523	23.727	0.000		20.826	24.523
Bonners Ferry, City of	107	2002	2	NT	FALSE			24.283	23.431	0.000		21.191	24.283
Bonners Ferry, City of	107	2002	3	NT	FALSE			8.500	8.500	0.000		6.761	8.500
Bonners Ferry, City of	107	2002	4	NT	FALSE			7.350	5.951	0.000		5.536	7.350
Bonners Ferry, City of	107	2002	5	NT	FALSE			7.099	3.192	0.000		2.723	7.099
Bonners Ferry, City of	107	2002	6	NT	FALSE			7.520	3.333	0.000		2.210	7.520
Bonners Ferry, City of	107	2002	7	NT	FALSE			7.175	3.205	0.000		2.669	7.175
Bonners Ferry, City of	107	2002	8	NT	FALSE			8.550	7.939	0.000		6.335	8.550
Bonners Ferry, City of	107	2002	9	NT	FALSE			10.598	7.339	0.000		5.433	10.598
Bonners Ferry, City of	107	2002	10	NT	FALSE			22.292	22.779	0.000		20.259	22.292
Bonners Ferry, City of	107	2002	11	NT	FALSE			23.270	22.044	0.000		19.905	23.270
Bonners Ferry, City of	107	2002	12	NT	FALSE			24.035	22.314	0.000		19.312	24.035
Bonners Ferry, City of	107	2003	1	NT	FALSE			24.540	23.744	0.000		20.840	24.540
Bonners Ferry, City of	107	2003	2	NT	FALSE			24.361	23.507	0.000		21.259	24.361
Bonners Ferry, City of	107	2003	3	NT	FALSE			8.527	8.527	0.000		6.783	8.527
Bonners Ferry, City of	107	2003	4	NT	FALSE			7.391	5.985	0.000		5.567	7.391
Bonners Ferry, City of	107	2003	5	NT	FALSE			7.159	3.219	0.000		2.746	7.159
Bonners Ferry, City of	107	2003	6	NT	FALSE			7.581	3.361	0.000		2.228	7.581
Bonners Ferry, City of	107	2003	7	NT	FALSE			7.240	3.234	0.000		2.693	7.240
Bonners Ferry, City of	107	2003	8	NT	FALSE			8.556	7.944	0.000		6.340	8.556
Central Montana Electric Pwr Coop	313	2000	7	NT	FALSE			130.376	102.997	0.000	63.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2000	8	NT	FALSE			133.185	104.284	0.000	66.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2000	9	NT	FALSE			120.051	80.914	0.000	54.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2000	10	NT	FALSE			113.244	96.031	0.000	49.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2000	11	NT	FALSE			130.701	114.886	0.000	69.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2000	12	NT	FALSE			173.272	169.980	0.000	86.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	1	NT	FALSE			199.280	189.515	0.000	86.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	2	NT	FALSE			150.972	147.047	0.000	85.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	3	NT	FALSE			154.990	154.990	0.000	70.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	4	NT	FALSE			128.434	119.958	0.000	71.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	5	NT	FALSE			115.935	94.487	0.000	48.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	6	NT	FALSE			120.944	113.083	0.000	53.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	7	NT	FALSE			138.488	109.405	0.000	63.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	8	NT	FALSE			140.292	109.848	0.000	66.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	9	NT	FALSE			120.076	80.931	0.000	54.000	0.000	0.000
Central Montana Electric Pwr Coop	313	2001	10	NT	FALSE			113.872	96.563	0.000	49.000	55.011	96.563
Central Montana Electric Pwr Coop	313	2001	11	NT	FALSE			131.559	115.641	0.000	69.000	54.990	115.641
Central Montana Electric Pwr Coop	313	2001	12	NT	FALSE			174.419	171.105	0.000	86.000	86.739	171.105
Central Montana Electric Pwr Coop	313	2002	1	NT	FALSE			199.420	189.649	0.000	86.000	107.863	189.649

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Central Montana Electric Pwr Coop	313	2002	2	NT	FALSE			151.461	147.523	0.000	85.000	64.733	147.523
Central Montana Electric Pwr Coop	313	2002	3	NT	FALSE			155.487	155.487	0.000	70.000	85.487	155.487
Central Montana Electric Pwr Coop	313	2002	4	NT	FALSE			129.157	120.633	0.000	71.000	54.319	120.633
Central Montana Electric Pwr Coop	313	2002	5	NT	FALSE			116.915	95.285	0.000	48.000	56.165	95.285
Central Montana Electric Pwr Coop	313	2002	6	NT	FALSE			121.929	114.003	0.000	53.000	64.448	114.003
Central Montana Electric Pwr Coop	313	2002	7	NT	FALSE			139.749	110.402	0.000	63.000	60.065	110.402
Central Montana Electric Pwr Coop	313	2002	8	NT	FALSE			140.389	109.924	0.000	66.000	58.246	109.924
Central Montana Electric Pwr Coop	313	2002	9	NT	FALSE			120.102	80.949	0.000	54.000	44.553	80.949
Central Montana Electric Pwr Coop	313	2002	10	NT	FALSE			114.503	97.098	0.000	49.000	55.546	97.098
Central Montana Electric Pwr Coop	313	2002	11	NT	FALSE			132.424	116.401	0.000	69.000	55.750	116.401
Central Montana Electric Pwr Coop	313	2002	12	NT	FALSE			175.574	172.238	0.000	86.000	87.872	172.238
Central Montana Electric Pwr Coop	313	2003	1	NT	FALSE			199.561	189.782	0.000	86.000	107.996	189.782
Central Montana Electric Pwr Coop	313	2003	2	NT	FALSE			151.951	148.000	0.000	85.000	65.210	148.000
Central Montana Electric Pwr Coop	313	2003	3	NT	FALSE			155.986	155.986	0.000	70.000	85.986	155.986
Central Montana Electric Pwr Coop	313	2003	4	NT	FALSE			129.885	121.312	0.000	71.000	54.998	121.312
Central Montana Electric Pwr Coop	313	2003	5	NT	FALSE			117.903	96.091	0.000	48.000	56.971	96.091
Central Montana Electric Pwr Coop	313	2003	6	NT	FALSE			122.921	114.931	0.000	53.000	65.376	114.931
Central Montana Electric Pwr Coop	313	2003	7	NT	FALSE			141.021	111.407	0.000	63.000	61.070	111.407
Central Montana Electric Pwr Coop	313	2003	8	NT	FALSE			140.486	110.001	0.000	66.000	58.323	110.001
Central Montana Electric Pwr Coop	313	2003	9	NT	FALSE			120.127	80.966	0.000	54.000	44.570	80.966
Clark County PUD	216	1998	10	NT	TRUE	434.152	645.944	597.685	477.704	150.000	155.880	418.518	569.388
Clark County PUD	216	1998	11	NT	TRUE	377.626	639.417	679.343	651.334	150.000	245.959	360.091	622.592
Clark County PUD	216	1998	12	NT	TRUE	728.888	1010.681	926.576	694.218	150.000	81.769	714.703	891.267
Clark County PUD	216	1999	1	NT	TRUE	435.387	785.178	784.081	688.894	150.000	191.858	417.449	776.400
Clark County PUD	216	1999	2	NT	TRUE	412.658	774.451	800.005	793.559	150.000	249.554	396.851	750.042
Clark County PUD	216	1999	3	NT	TRUE	414.673	726.468	890.604	591.626	150.000	172.579	414.673	726.468
Clark County PUD	216	1999	4	NT	TRUE	428.342	719.310	760.026	375.128	150.000	67.909	428.342	719.310
Clark County PUD	216	1999	5	NT	TRUE	312.266	625.852	740.206	543.674	150.000	198.911	312.266	625.852
Clark County PUD	216	1999	6	NT	TRUE	106.370	448.955	538.830	294.630	150.000	162.837	106.370	448.955
Clark County PUD	216	1999	7	NT	TRUE	164.473	498.675	443.224	130.704	150.000	21.014	164.473	498.675
Clark County PUD	216	1999	8	NT	TRUE	290.494	502.080	460.600	290.152	150.000	99.036	290.494	502.080
Clark County PUD	216	1999	9	NT	TRUE	297.495	531.080	535.500	357.850	150.000	124.385	297.495	531.080
Clark County PUD	216	1999	10	NT	TRUE	285.607	532.191	639.000	669.129	150.000	308.469	301.241	608.747
Clark County PUD	216	1999	11	NT	TRUE	351.023	647.609	725.000	729.891	150.000	281.141	368.558	664.434
Clark County PUD	216	1999	12	NT	TRUE	384.495	701.080	853.000	868.440	150.000	323.680	398.680	820.494
Clark County PUD	216	2000	1	NT	TRUE	434.219	819.033	836.000	752.647	150.000	206.807	452.157	827.811
Clark County PUD	216	2000	2	NT	TRUE	279.354	675.939	747.000	788.181	150.000	296.121	295.161	700.348
Clark County PUD	216	2000	3	NT	FALSE			844.950	557.842	150.000	172.579	373.037	689.228
Clark County PUD	216	2000	4	NT	FALSE			738.100	359.341	150.000	67.909	408.787	698.558
Clark County PUD	216	2000	5	NT	FALSE			653.170	474.915	150.000	198.911	246.975	552.262
Clark County PUD	216	2000	6	NT	FALSE			547.800	300.819	150.000	162.837	112.199	456.430
Clark County PUD	216	2000	7	NT	FALSE			450.300	135.727	150.000	21.014	169.314	506.636
Clark County PUD	216	2000	8	NT	FALSE			453.461	284.012	150.000	99.036	284.490	494.298
Clark County PUD	216	2000	9	NT	FALSE			518.295	343.570	150.000	124.385	283.969	514.017
Clark County PUD	216	2000	10	NT	FALSE			649.012	602.246	150.000	232.175	389.602	618.285
Clark County PUD	216	2000	11	NT	FALSE			735.040	721.837	150.000	263.550	396.596	673.636

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Clark County PUD	216	2000	12	NT	FALSE			863.793	757.414	150.000	202.724	532.281	830.877
Clark County PUD	216	2001	1	NT	FALSE			846.789	755.314	150.000	199.332	470.219	838.494
Clark County PUD	216	2001	2	NT	FALSE			843.897	859.857	150.000	272.838	417.218	791.193
Clark County PUD	216	2001	3	NT	FALSE			797.735	522.902	150.000	172.579	329.977	650.715
Clark County PUD	216	2001	4	NT	FALSE			681.262	318.418	150.000	67.909	358.097	644.766
Clark County PUD	216	2001	5	NT	FALSE			611.998	442.390	150.000	198.911	216.089	517.451
Clark County PUD	216	2001	6	NT	FALSE			506.291	272.178	150.000	162.837	85.227	421.844
Clark County PUD	216	2001	7	NT	FALSE			481.567	157.927	150.000	21.014	190.707	541.814
Clark County PUD	216	2001	8	NT	FALSE			484.768	310.936	0.000	99.036	310.817	528.424
Clark County PUD	216	2001	9	NT	FALSE			526.726	350.567	0.000	124.385	296.280	522.378
Clark County PUD	216	2001	10	NT	FALSE			659.181	611.805	0.000	232.175	387.456	619.630
Clark County PUD	216	2001	11	NT	FALSE			745.218	731.507	0.000	263.550	444.407	707.957
Clark County PUD	216	2001	12	NT	FALSE			874.723	767.470	0.000	202.724	602.021	804.746
Clark County PUD	216	2002	1	NT	FALSE			857.718	765.587	0.000	199.332	606.922	806.255
Clark County PUD	216	2002	2	NT	FALSE			858.027	873.704	0.000	272.838	568.029	840.866
Clark County PUD	216	2002	3	NT	FALSE			809.644	531.716	0.000	172.579	426.558	599.137
Clark County PUD	216	2002	4	NT	FALSE			691.681	325.919	0.000	67.909	430.102	498.011
Clark County PUD	216	2002	5	NT	FALSE			622.162	450.419	0.000	198.911	292.597	491.508
Clark County PUD	216	2002	6	NT	FALSE			514.719	277.994	0.000	162.837	192.319	355.156
Clark County PUD	216	2002	7	NT	FALSE			489.255	163.385	0.000	21.014	326.356	347.371
Clark County PUD	216	2002	8	NT	FALSE			492.325	317.436	0.000	99.036	324.364	423.400
Clark County PUD	216	2002	9	NT	FALSE			535.293	357.678	0.000	124.385	319.908	444.293
Clark County PUD	216	2002	10	NT	FALSE			669.510	621.514	0.000	232.175	397.165	629.339
Clark County PUD	216	2002	11	NT	FALSE			755.538	741.311	0.000	263.550	454.211	717.761
Clark County PUD	216	2002	12	NT	FALSE			885.792	777.653	0.000	202.724	612.204	814.928
Clark County PUD	216	2003	1	NT	FALSE			868.788	775.993	0.000	199.332	617.328	816.660
Clark County PUD	216	2003	2	NT	FALSE			872.393	887.783	0.000	272.838	582.108	854.945
Clark County PUD	216	2003	3	NT	FALSE			821.732	540.660	0.000	172.579	435.503	608.082
Clark County PUD	216	2003	4	NT	FALSE			702.260	333.536	0.000	67.909	437.718	505.627
Clark County PUD	216	2003	5	NT	FALSE			632.495	458.582	0.000	198.911	300.760	499.671
Clark County PUD	216	2003	6	NT	FALSE			523.288	283.906	0.000	162.837	198.232	361.069
Clark County PUD	216	2003	7	NT	FALSE			497.065	168.930	0.000	21.014	331.902	352.916
Clark County PUD	216	2003	8	NT	FALSE			500.000	324.036	0.000	99.036	330.964	430.000
Clark County PUD	216	2003	9	NT	FALSE			544.000	364.905	0.000	124.385	327.135	451.520
Consolidated Irrigation District #19	107	2003	9	NT	FALSE			10.600	7.341	0.000		5.435	10.600
Consolidated Irrigation District #19	192	1998	10	NTP	TRUE	0.261	0.353						
Consolidated Irrigation District #19	192	1998	11	NTP	TRUE	0.437	0.591						
Consolidated Irrigation District #19	192	1998	12	NTP	TRUE	0.430	0.581						
Consolidated Irrigation District #19	192	1999	1	NTP	TRUE	0.533	0.720						
Consolidated Irrigation District #19	192	1999	2	NTP	TRUE	0.505	0.683						
Consolidated Irrigation District #19	192	1999	3	NTP	TRUE	0.400	0.540						
Consolidated Irrigation District #19	192	1999	4	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	5	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	6	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	7	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	8	NTP	TRUE	0.461	0.623						

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(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Consolidated Irrigation District #19	192	1999	9	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	10	NTP	TRUE	0.461	0.623						
Consolidated Irrigation District #19	192	1999	11	NTP	TRUE	0.574	0.775						
Consolidated Irrigation District #19	192	1999	12	NTP	TRUE	0.307	0.415						
Consolidated Irrigation District #19	192	2000	1	NTP	TRUE	0.401	0.542						
Consolidated Irrigation District #19	192	2000	2	NTP	TRUE	0.301	0.407						
Consolidated Irrigation District #19	192	2000	3	NTP	FALSE			0.471	0.392	0.000		0.290	0.471
Consolidated Irrigation District #19	192	2000	4	NTP	FALSE			0.545	0.501	0.000		0.371	0.545
Consolidated Irrigation District #19	192	2000	5	NTP	FALSE			0.503	0.409	0.000		0.303	0.503
Consolidated Irrigation District #19	192	2000	6	NTP	FALSE			0.571	0.555	0.000		0.411	0.571
Consolidated Irrigation District #19	192	2000	7	NTP	FALSE			0.662	0.549	0.000		0.406	0.662
Consolidated Irrigation District #19	192	2000	8	NTP	FALSE			0.636	0.529	0.000		0.391	0.636
Consolidated Irrigation District #19	192	2000	9	NTP	FALSE			0.593	0.476	0.000		0.352	0.593
Consolidated Irrigation District #19	192	2000	10	NTP	FALSE			1.003	0.721	0.000		0.533	1.003
Consolidated Irrigation District #19	192	2000	11	NTP	FALSE			1.411	1.192	0.000		0.882	1.411
Consolidated Irrigation District #19	192	2000	12	NTP	FALSE			0.953	1.178	0.000		0.871	0.953
Consolidated Irrigation District #19	192	2001	1	NTP	FALSE			1.301	0.992	0.000		0.735	1.301
Consolidated Irrigation District #19	192	2001	2	NTP	FALSE			1.155	1.061	0.000		0.784	1.155
Consolidated Irrigation District #19	192	2001	3	NTP	FALSE			0.473	0.393	0.000		0.291	0.473
Consolidated Irrigation District #19	192	2001	4	NTP	FALSE			0.548	0.504	0.000		0.373	0.548
Consolidated Irrigation District #19	192	2001	5	NTP	FALSE			0.507	0.413	0.000		0.305	0.507
Consolidated Irrigation District #19	192	2001	6	NTP	FALSE			0.576	0.560	0.000		0.414	0.576
Consolidated Irrigation District #19	192	2001	7	NTP	FALSE			0.668	0.554	0.000		0.410	0.668
Consolidated Irrigation District #19	192	2001	8	NTP	FALSE			0.637	0.529	0.000		0.391	0.637
Consolidated Irrigation District #19	192	2001	9	NTP	FALSE			0.594	0.476	0.000		0.352	0.594
Consolidated Irrigation District #19	192	2001	10	NT	FALSE			1.008	0.725	0.000		0.536	1.008
Consolidated Irrigation District #19	192	2001	11	NT	FALSE			1.420	1.200	0.000		0.888	1.420
Consolidated Irrigation District #19	192	2001	12	NT	FALSE			0.959	1.186	0.000		0.877	0.959
Consolidated Irrigation District #19	192	2002	1	NT	FALSE			1.302	0.993	0.000		0.735	1.302
Consolidated Irrigation District #19	192	2002	2	NT	FALSE			1.158	1.064	0.000		0.787	1.158
Consolidated Irrigation District #19	192	2002	3	NT	FALSE			0.474	0.394	0.000		0.292	0.474
Consolidated Irrigation District #19	192	2002	4	NT	FALSE			0.551	0.507	0.000		0.375	0.551
Consolidated Irrigation District #19	192	2002	5	NT	FALSE			0.511	0.416	0.000		0.308	0.511
Consolidated Irrigation District #19	192	2002	6	NT	FALSE			0.580	0.564	0.000		0.418	0.580
Consolidated Irrigation District #19	192	2002	7	NT	FALSE			0.674	0.559	0.000		0.414	0.674
Consolidated Irrigation District #19	192	2002	8	NT	FALSE			0.637	0.529	0.000		0.392	0.637
Consolidated Irrigation District #19	192	2002	9	NT	FALSE			0.594	0.476	0.000		0.352	0.594
Consolidated Irrigation District #19	192	2002	10	NT	FALSE			1.014	0.729	0.000		0.539	1.014
Consolidated Irrigation District #19	192	2002	11	NT	FALSE			1.429	1.208	0.000		0.894	1.429
Consolidated Irrigation District #19	192	2002	12	NT	FALSE			0.965	1.193	0.000		0.883	0.965
Consolidated Irrigation District #19	192	2003	1	NT	FALSE			1.303	0.994	0.000		0.736	1.303
Consolidated Irrigation District #19	192	2003	2	NT	FALSE			1.162	1.067	0.000		0.789	1.162
Consolidated Irrigation District #19	192	2003	3	NT	FALSE			0.476	0.395	0.000		0.293	0.476
Consolidated Irrigation District #19	192	2003	4	NT	FALSE			0.554	0.509	0.000		0.377	0.554
Consolidated Irrigation District #19	192	2003	5	NT	FALSE			0.515	0.420	0.000		0.311	0.515
Consolidated Irrigation District #19	192	2003	6	NT	FALSE			0.585	0.569	0.000		0.421	0.585

Appendix D Table 2

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Consolidated Irrigation District #19	192	2003	7	NT	FALSE			0.680	0.564	0.000		0.417	0.680
Consolidated Irrigation District #19	192	2003	8	NT	FALSE			0.637	0.530	0.000		0.392	0.637
Consolidated Irrigation District #19	192	2003	9	NT	FALSE			0.594	0.476	0.000		0.352	0.594
Cowlitz County PUD	222	1998	10	NTP	TRUE	220.422	223.663	577.600	466.701	318.000	0.000	200.629	202.073
Cowlitz County PUD	222	1998	11	NTP	TRUE	6.236	6.236	608.950	498.121	318.000	0.000	101.351	101.351
Cowlitz County PUD	222	1998	12	NTP	TRUE	314.353	338.353	740.300	590.019	318.000	0.000	296.833	309.319
Cowlitz County PUD	222	1999	1	NTP	TRUE	225.431	242.531	643.150	526.740	318.000	0.000	221.314	229.094
Cowlitz County PUD	222	1999	2	NTP	TRUE	238.836	251.836	647.780	524.702	318.000	0.000	260.764	268.177
Cowlitz County PUD	222	1999	3	NTP	TRUE	187.344	229.344	718.750	606.625	318.000	0.000	187.344	229.344
Cowlitz County PUD	222	1999	4	NTP	TRUE	249.052	249.052	671.600	554.742	318.000	0.000	249.052	249.052
Cowlitz County PUD	222	1999	5	NTP	TRUE	201.947	214.473	691.250	534.336	318.000	0.000	201.947	214.473
Cowlitz County PUD	222	1999	6	NTP	TRUE	218.894	218.894	677.600	539.370	318.000	0.000	218.894	218.894
Cowlitz County PUD	222	1999	7	NTP	TRUE	191.056	191.056	476.900	394.873	318.000	0.000	191.056	191.056
Cowlitz County PUD	222	1999	8	NTP	TRUE	203.053	203.053	496.224	429.234	318.000	0.000	203.053	203.053
Cowlitz County PUD	222	1999	9	NTP	TRUE	213.038	213.338	545.066	515.632	318.000	0.000	213.038	213.338
Cowlitz County PUD	222	1999	10	NTP	TRUE	230.119	230.119	611.368	493.986	288.000	0.000	249.912	251.709
Cowlitz County PUD	222	1999	11	NTP	TRUE	219.547	219.547	645.212	527.783	288.000	0.000	124.432	124.432
Cowlitz County PUD	222	1999	12	NTP	TRUE	256.228	256.228	677.456	539.932	288.000	0.000	273.748	285.262
Cowlitz County PUD	222	2000	1	NTP	TRUE	260.980	260.980	677.476	554.853	288.000	0.000	265.097	274.417
Cowlitz County PUD	222	2000	2	NTP	TRUE	266.122	267.478	596.825	483.428	288.000	0.000	244.194	251.137
Cowlitz County PUD	222	2000	3	NTP	FALSE			674.031	568.882	288.000	0.000	180.463	220.921
Cowlitz County PUD	222	2000	4	NTP	FALSE			646.017	533.610	288.000	0.000	252.163	252.163
Cowlitz County PUD	222	2000	5	NTP	FALSE			605.076	467.723	288.000	0.000	171.554	182.195
Cowlitz County PUD	222	2000	6	NTP	FALSE			683.113	543.758	288.000	0.000	240.511	240.511
Cowlitz County PUD	222	2000	7	NTP	FALSE			481.242	398.469	288.000	0.000	232.348	232.348
Cowlitz County PUD	222	2000	8	NTP	FALSE			481.367	416.383	288.000	0.000	220.306	220.306
Cowlitz County PUD	222	2000	9	NTP	FALSE			519.220	491.182	288.000	0.000	216.935	217.241
Cowlitz County PUD	222	2000	10	NTP	FALSE			614.755	496.722	285.000	0.000	254.848	256.681
Cowlitz County PUD	222	2000	11	NTP	FALSE			649.451	531.251	285.000	0.000	126.954	126.954
Cowlitz County PUD	222	2000	12	NTP	FALSE			681.941	543.507	285.000	0.000	279.009	290.744
Cowlitz County PUD	222	2001	1	NTP	FALSE			677.953	555.243	285.000	0.000	267.464	276.867
Cowlitz County PUD	222	2001	2	NTP	FALSE			665.284	538.880	285.000	0.000	300.698	309.247
Cowlitz County PUD	222	2001	3	NTP	FALSE			629.018	530.891	285.000	0.000	160.823	196.877
Cowlitz County PUD	222	2001	4	NTP	FALSE			590.595	487.831	285.000	0.000	215.241	215.241
Cowlitz County PUD	222	2001	5	NTP	FALSE			562.386	434.724	285.000	0.000	150.080	159.389
Cowlitz County PUD	222	2001	6	NTP	FALSE			626.065	498.348	285.000	0.000	207.611	207.611
Cowlitz County PUD	222	2001	7	NTP	FALSE			511.183	423.260	285.000	0.000	271.955	271.955
Cowlitz County PUD	222	2001	8	NTP	FALSE			507.054	438.601	285.000	0.000	252.989	252.989
Cowlitz County PUD	222	2001	9	NTP	FALSE			519.330	491.286	285.000	0.000	219.853	220.163
Cowlitz County PUD	222	2001	10	NT	FALSE			618.161	499.474	135.000	0.000	425.474	499.474
Cowlitz County PUD	222	2001	11	NT	FALSE			653.718	534.741	135.000	0.000	460.741	534.741
Cowlitz County PUD	222	2001	12	NT	FALSE			686.456	547.106	135.000	0.000	473.106	547.106
Cowlitz County PUD	222	2002	1	NT	FALSE			678.430	555.634	135.000	0.000	481.634	555.634
Cowlitz County PUD	222	2002	2	NT	FALSE			667.437	540.624	135.000	0.000	466.624	540.624
Cowlitz County PUD	222	2002	3	NT	FALSE			631.037	532.595	135.000	0.000	458.595	532.595
Cowlitz County PUD	222	2002	4	NT	FALSE			593.920	490.578	135.000	0.000	416.578	490.578

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(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Cowlitz County PUD	222	2002	5	NT	FALSE			567.139	438.398	135.000	0.000	364.398	438.398
Cowlitz County PUD	222	2002	6	NT	FALSE			631.159	502.403	135.000	0.000	428.403	502.403
Cowlitz County PUD	222	2002	7	NT	FALSE			515.838	427.113	135.000	0.000	353.113	427.113
Cowlitz County PUD	222	2002	8	NT	FALSE			507.405	438.906	135.000	0.000	364.906	438.906
Cowlitz County PUD	222	2002	9	NT	FALSE			519.440	491.391	135.000	0.000	417.391	491.391
Cowlitz County PUD	222	2002	10	NT	FALSE			621.585	502.241	135.000	0.000	428.241	502.241
Cowlitz County PUD	222	2002	11	NT	FALSE			658.013	538.255	135.000	0.000	464.255	538.255
Cowlitz County PUD	222	2002	12	NT	FALSE			691.001	550.728	135.000	0.000	476.728	550.728
Cowlitz County PUD	222	2003	1	NT	FALSE			678.907	556.025	135.000	0.000	482.025	556.025
Cowlitz County PUD	222	2003	2	NT	FALSE			669.596	542.373	135.000	0.000	468.373	542.373
Cowlitz County PUD	222	2003	3	NT	FALSE			633.062	534.304	135.000	0.000	460.304	534.304
Cowlitz County PUD	222	2003	4	NT	FALSE			597.264	493.340	135.000	0.000	419.340	493.340
Cowlitz County PUD	222	2003	5	NT	FALSE			571.931	442.103	135.000	0.000	368.103	442.103
Cowlitz County PUD	222	2003	6	NT	FALSE			636.295	506.491	135.000	0.000	432.491	506.491
Cowlitz County PUD	222	2003	7	NT	FALSE			520.534	431.002	135.000	0.000	357.002	431.002
Cowlitz County PUD	222	2003	8	NT	FALSE			507.757	439.210	135.000	0.000	365.210	439.210
Cowlitz County PUD	222	2003	9	NT	FALSE			519.550	491.495	135.000	0.000	417.495	491.495
Energy Northwest, Inc.	841	1998	10	NT	TRUE	0.000	0.000						
Energy Northwest, Inc.	841	1998	11	NT	TRUE	0.000	0.000						
Energy Northwest, Inc.	841	1998	12	NT	TRUE	0.000	0.000						
Energy Northwest, Inc.	841	1999	1	NT	TRUE	0.000	0.000						
Energy Northwest, Inc.	841	1999	2	NT	TRUE	0.000	0.000						
Energy Northwest, Inc.	841	1999	3	NT	TRUE	20.908	35.508						
Energy Northwest, Inc.	841	1999	4	NT	TRUE	17.191	31.790						
Energy Northwest, Inc.	841	1999	5	NT	TRUE	17.242	31.842						
Energy Northwest, Inc.	841	1999	6	NT	TRUE	11.260	25.861						
Energy Northwest, Inc.	841	1999	7	NT	TRUE	15.487	30.087						
Energy Northwest, Inc.	841	1999	8	NT	TRUE	13.382	27.981						
Energy Northwest, Inc.	841	1999	9	NT	TRUE	12.929	26.729						
Energy Northwest, Inc.	841	1999	10	NT	TRUE	13.619	27.818						
Energy Northwest, Inc.	841	1999	11	NT	TRUE	24.207	37.807						
Energy Northwest, Inc.	841	1999	12	NT	TRUE	24.514	38.113						
Energy Northwest, Inc.	841	2000	1	NT	TRUE	26.409	40.009						
Energy Northwest, Inc.	841	2000	2	NT	TRUE	27.554	41.154						
Energy Northwest, Inc.	841	2000	3	NT	FALSE			30.976	30.976	14.000		18.239	30.976
Energy Northwest, Inc.	841	2000	4	NT	FALSE			27.799	27.799	14.000		15.033	27.799
Energy Northwest, Inc.	841	2000	5	NT	FALSE			25.689	25.689	14.000		13.910	25.689
Energy Northwest, Inc.	841	2000	6	NT	FALSE			23.701	23.701	14.000		10.320	23.701
Energy Northwest, Inc.	841	2000	7	NT	FALSE			31.959	31.959	14.000		16.451	31.959
Energy Northwest, Inc.	841	2000	8	NT	FALSE			28.572	28.572	14.000		13.665	28.572
Energy Northwest, Inc.	841	2000	9	NT	FALSE			25.462	25.462	14.000		12.316	25.462
Energy Northwest, Inc.	841	2000	10	NT	FALSE			28.049	28.049	14.000		13.732	28.049
Energy Northwest, Inc.	841	2000	11	NT	FALSE			38.180	38.180	14.000		24.446	38.180
Energy Northwest, Inc.	841	2000	12	NT	FALSE			38.492	38.492	14.000		24.758	38.492
Energy Northwest, Inc.	841	2001	1	NT	FALSE			40.051	40.051	14.000		26.437	40.051
Energy Northwest, Inc.	841	2001	2	NT	FALSE			45.949	45.949	14.000		30.764	45.949

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
Energy Northwest, Inc.	841	2001	3	NT	FALSE			31.075	31.075	14.000		18.298	31.075
Energy Northwest, Inc.	841	2001	4	NT	FALSE			27.956	27.956	14.000		15.118	27.956
Energy Northwest, Inc.	841	2001	5	NT	FALSE			25.906	25.906	14.000		14.028	25.906
Energy Northwest, Inc.	841	2001	6	NT	FALSE			23.894	23.894	14.000		10.404	23.894
Energy Northwest, Inc.	841	2001	7	NT	FALSE			32.250	32.250	14.000		16.600	32.250
Energy Northwest, Inc.	841	2001	8	NT	FALSE			28.592	28.592	14.000		13.674	28.592
Energy Northwest, Inc.	841	2001	9	NT	FALSE			25.467	25.467	14.000		12.319	25.467
Energy Northwest, Inc.	841	2001	10	NT	FALSE			28.205	28.205	14.000		13.808	28.205
Energy Northwest, Inc.	841	2001	11	NT	FALSE			38.431	38.431	14.000		24.607	38.431
Energy Northwest, Inc.	841	2001	12	NT	FALSE			38.747	38.747	14.000		24.922	38.747
Energy Northwest, Inc.	841	2002	1	NT	FALSE			40.079	40.079	14.000		26.455	40.079
Energy Northwest, Inc.	841	2002	2	NT	FALSE			46.097	46.097	14.000		30.864	46.097
Energy Northwest, Inc.	841	2002	3	NT	FALSE			31.175	31.175	14.000		18.356	31.175
Energy Northwest, Inc.	841	2002	4	NT	FALSE			28.113	28.113	14.000		15.203	28.113
Energy Northwest, Inc.	841	2002	5	NT	FALSE			26.125	26.125	14.000		14.146	26.125
Energy Northwest, Inc.	841	2002	6	NT	FALSE			24.089	24.089	14.000		10.488	24.089
Energy Northwest, Inc.	841	2002	7	NT	FALSE			32.544	32.544	14.000		16.751	32.544
Energy Northwest, Inc.	841	2002	8	NT	FALSE			28.611	28.611	14.000		13.684	28.611
Energy Northwest, Inc.	841	2002	9	NT	FALSE			25.472	25.472	14.000		12.321	25.472
Energy Northwest, Inc.	841	2002	10	NT	FALSE			28.361	28.361	14.000		13.885	28.361
Energy Northwest, Inc.	841	2002	11	NT	FALSE			38.684	38.684	14.000		24.768	38.684
Energy Northwest, Inc.	841	2002	12	NT	FALSE			39.004	39.004	14.000		25.087	39.004
Energy Northwest, Inc.	841	2003	1	NT	FALSE			40.108	40.108	14.000		26.474	40.108
Energy Northwest, Inc.	841	2003	2	NT	FALSE			46.247	46.247	14.000		30.964	46.247
Energy Northwest, Inc.	841	2003	3	NT	FALSE			31.275	31.275	14.000		18.415	31.275
Energy Northwest, Inc.	841	2003	4	NT	FALSE			28.271	28.271	14.000		15.288	28.271
Energy Northwest, Inc.	841	2003	5	NT	FALSE			26.346	26.346	14.000		14.266	26.346
Energy Northwest, Inc.	841	2003	6	NT	FALSE			24.285	24.285	14.000		10.574	24.285
Energy Northwest, Inc.	841	2003	7	NT	FALSE			32.840	32.840	14.000		16.904	32.840
Energy Northwest, Inc.	841	2003	8	NT	FALSE			28.631	28.631	14.000		13.693	28.631
Energy Northwest, Inc.	841	2003	9	NT	FALSE			25.478	25.478	14.000		12.324	25.478
Okanogan County PUD	266	1998	10	NTP	TRUE	36.000	37.149	93.351	86.701	11.000	46.351	36.000	36.910
Okanogan County PUD	266	1998	11	NTP	TRUE	36.000	41.064	113.530	93.887	11.000	66.530	36.000	38.279
Okanogan County PUD	266	1998	12	NTP	TRUE	69.000	76.400	150.155	146.889	11.000	70.155	69.000	74.927
Okanogan County PUD	266	1999	1	NTP	TRUE	60.000	64.400	123.979	123.959	11.000	52.979	60.000	62.203
Okanogan County PUD	266	1999	2	NTP	TRUE	60.000	60.700	122.995	113.519	11.000	51.995	60.000	60.564
Okanogan County PUD	266	1999	3	NTP	TRUE	41.000	45.045	121.052	137.105	11.000	69.052	41.000	45.045
Okanogan County PUD	266	1999	4	NTP	TRUE	35.000	38.416	107.254	116.509	11.000	61.254	35.000	38.416
Okanogan County PUD	266	1999	5	NTP	TRUE	31.000	31.300	111.884	112.313	11.000	69.884	31.000	31.300
Okanogan County PUD	266	1999	6	NTP	TRUE	16.000	16.300	95.992	96.858	11.000	68.992	16.000	16.300
Okanogan County PUD	266	1999	7	NTP	TRUE	30.000	31.763	82.182	43.586	11.000	41.182	30.000	31.763
Okanogan County PUD	266	1999	8	NTP	TRUE	33.000	33.700	82.320	58.502	11.000	38.320	33.000	33.700
Okanogan County PUD	266	1999	9	NTP	TRUE	37.000	42.238	98.700	79.818	11.000	50.700	37.000	42.238
Okanogan County PUD	266	1999	10	NTP	TRUE	44.000	44.874	99.000	90.000	11.000	44.000	44.000	45.113
Okanogan County PUD	266	1999	11	NTP	TRUE	44.000	44.000	120.000	96.880	11.000	65.000	44.000	46.785
Okanogan County PUD	266	1999	12	NTP	TRUE	44.000	46.307	137.000	147.368	11.000	82.000	44.000	47.780

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Okanogan County PUD	266	2000	1	NTP	TRUE	68.000	68.300	131.000	130.000	11.000	52.000	68.000	70.497
Okanogan County PUD	266	2000	2	NTP	TRUE	57.000	57.400	113.400	98.068	11.000	45.400	57.000	57.536
Okanogan County PUD	266	2000	3	NTP	FALSE			113.950	130.002	11.000	69.052	33.898	37.242
Okanogan County PUD	266	2000	4	NTP	FALSE			103.400	112.654	11.000	61.254	31.146	34.186
Okanogan County PUD	266	2000	5	NTP	FALSE			97.650	100.300	11.000	69.884	16.766	16.928
Okanogan County PUD	266	2000	6	NTP	FALSE			96.800	97.530	11.000	68.992	16.808	17.123
Okanogan County PUD	266	2000	7	NTP	FALSE			82.650	43.896	11.000	41.182	30.468	32.259
Okanogan County PUD	266	2000	8	NTP	FALSE			80.271	56.681	11.000	38.320	30.951	31.608
Okanogan County PUD	266	2000	9	NTP	FALSE			94.741	76.525	11.000	50.700	33.041	37.719
Okanogan County PUD	266	2000	10	NTP	FALSE			99.742	91.917	11.000	45.175	43.566	44.668
Okanogan County PUD	266	2000	11	NTP	FALSE			120.497	97.992	11.000	65.765	43.732	46.500
Okanogan County PUD	266	2000	12	NTP	FALSE			137.497	141.875	11.000	76.077	50.420	54.751
Okanogan County PUD	266	2001	1	NTP	FALSE			131.497	130.987	11.000	52.490	68.007	70.504
Okanogan County PUD	266	2001	2	NTP	FALSE			126.497	113.454	11.000	48.697	66.800	67.428
Okanogan County PUD	266	2001	3	NTP	FALSE			106.742	122.795	11.000	69.052	26.690	29.323
Okanogan County PUD	266	2001	4	NTP	FALSE			94.741	103.995	11.000	61.254	22.487	24.682
Okanogan County PUD	266	2001	5	NTP	FALSE			90.496	94.262	11.000	69.884	9.612	9.705
Okanogan County PUD	266	2001	6	NTP	FALSE			88.741	90.824	11.000	68.992	8.748	8.912
Okanogan County PUD	266	2001	7	NTP	FALSE			87.496	47.104	11.000	41.182	35.314	37.389
Okanogan County PUD	266	2001	8	NTP	FALSE			84.994	60.880	11.000	38.320	35.674	36.431
Okanogan County PUD	266	2001	9	NTP	FALSE			95.488	77.146	11.000	50.700	33.788	38.571
Okanogan County PUD	266	2001	10	NT	FALSE			100.489	92.664	0.000	56.175	44.313	100.489
Okanogan County PUD	266	2001	11	NT	FALSE			120.996	98.341	0.000	76.765	7.811	84.576
Okanogan County PUD	266	2001	12	NT	FALSE			137.996	142.306	0.000	87.077	32.151	119.229
Okanogan County PUD	266	2002	1	NT	FALSE			131.996	131.486	0.000	63.490	68.506	131.996
Okanogan County PUD	266	2002	2	NT	FALSE			126.996	113.915	0.000	59.697	57.520	117.217
Okanogan County PUD	266	2002	3	NT	FALSE			107.490	123.542	0.000	80.052	27.437	107.490
Okanogan County PUD	266	2002	4	NT	FALSE			95.488	104.743	0.000	72.254	23.234	95.488
Okanogan County PUD	266	2002	5	NT	FALSE			90.995	94.683	0.000	80.884	0.000	76.799
Okanogan County PUD	266	2002	6	NT	FALSE			89.487	91.446	0.000	79.992	0.000	74.454
Okanogan County PUD	266	2002	7	NT	FALSE			87.994	47.434	0.000	52.182	6.071	58.252
Okanogan County PUD	266	2002	8	NT	FALSE			85.496	61.326	0.000	49.320	26.686	76.006
Okanogan County PUD	266	2002	9	NT	FALSE			96.241	77.773	0.000	61.700	18.373	80.073
Okanogan County PUD	266	2002	10	NT	FALSE			101.242	93.417	0.000	56.175	45.066	101.242
Okanogan County PUD	266	2002	11	NT	FALSE			121.497	98.691	0.000	76.765	8.161	84.926
Okanogan County PUD	266	2002	12	NT	FALSE			138.497	142.739	0.000	87.077	32.584	119.662
Okanogan County PUD	266	2003	1	NT	FALSE			132.497	131.987	0.000	63.490	69.007	132.497
Okanogan County PUD	266	2003	2	NT	FALSE			127.497	114.377	0.000	59.697	57.982	117.680
Okanogan County PUD	266	2003	3	NT	FALSE			108.242	124.295	0.000	80.052	28.190	108.242
Okanogan County PUD	266	2003	4	NT	FALSE			96.241	105.495	0.000	72.254	23.987	96.241
Okanogan County PUD	266	2003	5	NT	FALSE			91.496	95.106	0.000	80.884	0.000	77.223
Okanogan County PUD	266	2003	6	NT	FALSE			90.241	92.072	0.000	79.992	0.000	75.080
Okanogan County PUD	266	2003	7	NT	FALSE			88.496	47.766	0.000	52.182	6.402	58.584
Okanogan County PUD	266	2003	8	NT	FALSE			86.000	61.774	0.000	49.320	27.134	76.454
Okanogan County PUD	266	2003	9	NT	FALSE			97.000	78.404	0.000	61.700	19.004	80.704
Pend Oreille County PUD	273	1998	10	NTP	TRUE	31.014	31.508	118.465	113.963	51.000	0.000	38.054	38.289

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Pend Oreille County PUD	273	1998	11	NTP	TRUE	44.728	44.728	123.595	96.281	51.000	0.000	41.272	46.112
Pend Oreille County PUD	273	1998	12	NTP	TRUE	63.161	64.608	153.450	112.632	51.000	0.000	58.286	59.058
Pend Oreille County PUD	273	1999	1	NTP	TRUE	56.461	57.211	134.235	104.838	51.000	0.000	51.993	57.812
Pend Oreille County PUD	273	1999	2	NTP	TRUE	56.536	56.536	149.352	77.962	51.000	0.000	58.247	59.734
Pend Oreille County PUD	273	1999	3	NTP	TRUE	47.626	53.604	158.700	70.304	51.000	0.000	47.626	53.604
Pend Oreille County PUD	273	1999	4	NTP	TRUE	50.678	50.678	154.100	95.696	51.000	0.000	50.678	50.678
Pend Oreille County PUD	273	1999	5	NTP	TRUE	31.776	31.776	163.250	118.683	51.000	0.000	31.776	31.776
Pend Oreille County PUD	273	1999	6	NTP	TRUE	20.671	20.777	132.990	129.399	51.000	0.000	20.671	20.777
Pend Oreille County PUD	273	1999	7	NTP	TRUE	27.581	27.581	106.780	100.694	51.000	0.000	27.581	27.581
Pend Oreille County PUD	273	1999	8	NTP	TRUE	24.514	24.514	107.483	104.688	51.000	0.000	24.514	24.514
Pend Oreille County PUD	273	1999	9	NTP	TRUE	48.708	48.708	118.465	91.100	51.000	0.000	48.708	48.708
Pend Oreille County PUD	273	1999	10	NTP	TRUE	49.000	49.000	125.391	120.626	51.000	0.000	41.960	42.219
Pend Oreille County PUD	273	1999	11	NTP	TRUE	42.000	52.170	130.955	102.014	51.000	0.000	45.456	50.786
Pend Oreille County PUD	273	1999	12	NTP	TRUE	46.000	46.000	140.424	103.071	51.000	0.000	50.875	51.550
Pend Oreille County PUD	273	2000	1	NTP	TRUE	52.000	63.388	141.399	110.433	51.000	0.000	56.468	62.787
Pend Oreille County PUD	273	2000	2	NTP	TRUE	53.000	55.797	137.604	71.829	51.000	0.000	51.289	52.599
Pend Oreille County PUD	273	2000	3	NTP	FALSE			148.826	65.930	51.000	0.000	43.260	48.690
Pend Oreille County PUD	273	2000	4	NTP	FALSE			148.230	92.051	51.000	0.000	47.793	47.793
Pend Oreille County PUD	273	2000	5	NTP	FALSE			142.898	103.887	51.000	0.000	26.015	26.015
Pend Oreille County PUD	273	2000	6	NTP	FALSE			134.072	130.452	51.000	0.000	20.944	21.051
Pend Oreille County PUD	273	2000	7	NTP	FALSE			107.752	101.610	51.000	0.000	28.062	28.062
Pend Oreille County PUD	273	2000	8	NTP	FALSE			104.264	101.554	51.000	0.000	23.117	23.117
Pend Oreille County PUD	273	2000	9	NTP	FALSE			112.848	86.780	51.000	0.000	44.653	44.653
Pend Oreille County PUD	273	2000	10	NTP	FALSE			126.085	121.294	51.000	0.000	42.352	42.613
Pend Oreille County PUD	273	2000	11	NTP	FALSE			131.815	102.684	51.000	0.000	45.945	51.333
Pend Oreille County PUD	273	2000	12	NTP	FALSE			141.353	103.753	51.000	0.000	51.404	52.085
Pend Oreille County PUD	273	2001	1	NTP	FALSE			141.499	110.511	51.000	0.000	56.530	62.857
Pend Oreille County PUD	273	2001	2	NTP	FALSE			153.388	80.068	51.000	0.000	60.637	62.185
Pend Oreille County PUD	273	2001	3	NTP	FALSE			138.887	61.527	51.000	0.000	38.864	43.743
Pend Oreille County PUD	273	2001	4	NTP	FALSE			135.513	84.154	51.000	0.000	41.542	41.542
Pend Oreille County PUD	273	2001	5	NTP	FALSE			132.817	96.558	51.000	0.000	23.161	23.161
Pend Oreille County PUD	273	2001	6	NTP	FALSE			122.875	119.558	51.000	0.000	18.121	18.214
Pend Oreille County PUD	273	2001	7	NTP	FALSE			114.456	107.932	51.000	0.000	31.376	31.376
Pend Oreille County PUD	273	2001	8	NTP	FALSE			109.828	106.973	51.000	0.000	25.532	25.532
Pend Oreille County PUD	273	2001	9	NTP	FALSE			112.872	86.798	51.000	0.000	44.670	44.670
Pend Oreille County PUD	273	2001	10	NT	FALSE			126.784	121.966	51.000	0.000	121.666	121.966
Pend Oreille County PUD	273	2001	11	NT	FALSE			132.681	103.359	51.000	0.000	103.059	103.359
Pend Oreille County PUD	273	2001	12	NT	FALSE			142.289	104.440	51.000	0.000	104.140	104.440
Pend Oreille County PUD	273	2002	1	NT	FALSE			141.598	110.588	51.000	0.000	110.288	110.588
Pend Oreille County PUD	273	2002	2	NT	FALSE			153.884	80.328	51.000	0.000	80.028	80.328
Pend Oreille County PUD	273	2002	3	NT	FALSE			139.333	61.724	51.000	0.000	61.324	61.724
Pend Oreille County PUD	273	2002	4	NT	FALSE			136.276	84.628	51.000	0.000	84.228	84.628
Pend Oreille County PUD	273	2002	5	NT	FALSE			133.939	97.374	51.000	0.000	96.974	97.374
Pend Oreille County PUD	273	2002	6	NT	FALSE			123.875	120.531	51.000	0.000	120.131	120.531
Pend Oreille County PUD	273	2002	7	NT	FALSE			115.498	108.915	51.000	0.000	108.615	108.915
Pend Oreille County PUD	273	2002	8	NT	FALSE			109.904	107.047	51.000	0.000	106.747	107.047

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Pend Oreille County PUD	273	2002	9	NT	FALSE			112.896	86.817	51.000	0.000	86.517	86.817
Pend Oreille County PUD	273	2002	10	NT	FALSE			127.486	122.642	51.000	0.000	122.342	122.642
Pend Oreille County PUD	273	2002	11	NT	FALSE			133.553	104.038	51.000	0.000	103.738	104.038
Pend Oreille County PUD	273	2002	12	NT	FALSE			143.231	105.132	51.000	0.000	104.832	105.132
Pend Oreille County PUD	273	2003	1	NT	FALSE			141.698	110.666	51.000	0.000	110.366	110.666
Pend Oreille County PUD	273	2003	2	NT	FALSE			154.382	80.587	51.000	0.000	80.287	80.587
Pend Oreille County PUD	273	2003	3	NT	FALSE			139.780	61.923	51.000	0.000	61.523	61.923
Pend Oreille County PUD	273	2003	4	NT	FALSE			137.044	85.104	51.000	0.000	84.704	85.104
Pend Oreille County PUD	273	2003	5	NT	FALSE			135.071	98.197	51.000	0.000	97.797	98.197
Pend Oreille County PUD	273	2003	6	NT	FALSE			124.883	121.511	51.000	0.000	121.111	121.511
Pend Oreille County PUD	273	2003	7	NT	FALSE			116.550	109.907	51.000	0.000	109.607	109.907
Pend Oreille County PUD	273	2003	8	NT	FALSE			109.981	107.121	51.000	0.000	106.821	107.121
Pend Oreille County PUD	273	2003	9	NT	FALSE			112.920	86.835	51.000	0.000	86.535	86.835
Port Townsend Paper Co.	716	1998	10	NTP	TRUE	18.400	0.000	14.820	12.849	0.000	0.000	18.363	0.000
Port Townsend Paper Co.	716	1998	11	NTP	TRUE	18.400	0.000	14.820	13.768	0.000	0.000	18.353	0.000
Port Townsend Paper Co.	716	1998	12	NTP	TRUE	18.400	0.000	17.160	15.942	0.000	0.000	19.738	0.000
Port Townsend Paper Co.	716	1999	1	NTP	TRUE	18.400	0.000	14.830	13.688	0.000	0.000	18.408	0.000
Port Townsend Paper Co.	716	1999	2	NTP	TRUE	18.400	0.000	15.337	15.337	0.000	0.000	19.673	0.000
Port Townsend Paper Co.	716	1999	3	NTP	TRUE	18.400	0.000	17.998	16.504	0.000	0.000	18.400	0.000
Port Townsend Paper Co.	716	1999	4	NTP	TRUE	19.400	0.000	18.041	16.544	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	5	NTP	TRUE	19.400	0.000	19.665	3.028	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	6	NTP	TRUE	19.400	0.000	17.300	15.137	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	7	NTP	TRUE	19.400	0.000	14.955	13.714	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	8	NTP	TRUE	19.400	0.000	15.299	12.744	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	9	NTP	TRUE	19.400	0.000	16.383	15.024	0.000	0.000	19.400	0.000
Port Townsend Paper Co.	716	1999	10	NTP	TRUE	19.400	0.000	15.686	13.600	0.000	0.000	19.437	0.000
Port Townsend Paper Co.	716	1999	11	NTP	TRUE	19.400	0.000	15.702	14.588	0.000	0.000	19.447	0.000
Port Townsend Paper Co.	716	1999	12	NTP	TRUE	19.400	0.000	15.703	14.588	0.000	0.000	18.062	0.000
Port Townsend Paper Co.	716	2000	1	NTP	TRUE	19.400	0.000	15.622	14.419	0.000	0.000	19.392	0.000
Port Townsend Paper Co.	716	2000	2	NTP	TRUE	19.400	0.000	14.131	14.131	0.000	0.000	18.127	0.000
Port Townsend Paper Co.	716	2000	3	NTP	FALSE			16.878	15.477	0.000	0.000	17.255	0.000
Port Townsend Paper Co.	716	2000	4	NTP	FALSE			17.354	15.913	0.000	0.000	18.660	0.000
Port Townsend Paper Co.	716	2000	5	NTP	FALSE			17.213	2.651	0.000	0.000	16.985	0.000
Port Townsend Paper Co.	716	2000	6	NTP	FALSE			17.440	15.260	0.000	0.000	19.558	0.000
Port Townsend Paper Co.	716	2000	7	NTP	FALSE			15.091	13.839	0.000	0.000	19.577	0.000
Port Townsend Paper Co.	716	2000	8	NTP	FALSE			14.841	12.362	0.000	0.000	18.818	0.000
Port Townsend Paper Co.	716	2000	9	NTP	FALSE			15.607	14.311	0.000	0.000	18.479	0.000
Port Townsend Paper Co.	716	2000	10	NTP	FALSE			15.773	13.675	0.000	0.000	19.544	0.000
Port Townsend Paper Co.	716	2000	11	NTP	FALSE			15.806	14.683	0.000	0.000	19.573	0.000
Port Townsend Paper Co.	716	2000	12	NTP	FALSE			15.807	14.685	0.000	0.000	18.182	0.000
Port Townsend Paper Co.	716	2001	1	NTP	FALSE			15.633	14.429	0.000	0.000	19.405	0.000
Port Townsend Paper Co.	716	2001	2	NTP	FALSE			15.752	15.752	0.000	0.000	20.206	0.000
Port Townsend Paper Co.	716	2001	3	NTP	FALSE			15.751	14.443	0.000	0.000	16.102	0.000
Port Townsend Paper Co.	716	2001	4	NTP	FALSE			15.865	14.548	0.000	0.000	17.059	0.000
Port Townsend Paper Co.	716	2001	5	NTP	FALSE			15.999	2.464	0.000	0.000	15.787	0.000
Port Townsend Paper Co.	716	2001	6	NTP	FALSE			15.984	13.986	0.000	0.000	17.925	0.000

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Customer	CustNo	Year	Month	Choice	History	Actual Base	Actual Load Shaping	Forecasted System Load, Nominal	Forecasted System Load, CP	Contract CSL, Nominal	Internal Generation, Nominal	Forecast Base	Forecast Load Shaping
Port Townsend Paper Co.	716	2001	7	NTP	FALSE			16.030	14.700	0.000	0.000	20.795	0.000
Port Townsend Paper Co.	716	2001	8	NTP	FALSE			15.632	13.022	0.000	0.000	19.823	0.000
Port Townsend Paper Co.	716	2001	9	NTP	FALSE			15.610	14.314	0.000	0.000	18.483	0.000
Port Townsend Paper Co.	716	2001	10	NT	FALSE			15.861	13.751	0.000	0.000	13.751	13.751
Port Townsend Paper Co.	716	2001	11	NT	FALSE			15.910	14.780	0.000	0.000	14.780	14.780
Port Townsend Paper Co.	716	2001	12	NT	FALSE			15.912	14.782	0.000	0.000	14.782	14.782
Port Townsend Paper Co.	716	2002	1	NT	FALSE			15.644	14.439	0.000	0.000	14.439	14.439
Port Townsend Paper Co.	716	2002	2	NT	FALSE			15.803	15.803	0.000	0.000	15.803	15.803
Port Townsend Paper Co.	716	2002	3	NT	FALSE			15.801	14.490	0.000	0.000	14.490	14.490
Port Townsend Paper Co.	716	2002	4	NT	FALSE			15.954	14.630	0.000	0.000	14.630	14.630
Port Townsend Paper Co.	716	2002	5	NT	FALSE			16.134	2.485	0.000	0.000	2.485	2.485
Port Townsend Paper Co.	716	2002	6	NT	FALSE			16.114	14.100	0.000	0.000	14.100	14.100
Port Townsend Paper Co.	716	2002	7	NT	FALSE			16.176	14.833	0.000	0.000	14.833	14.833
Port Townsend Paper Co.	716	2002	8	NT	FALSE			15.643	13.031	0.000	0.000	13.031	13.031
Port Townsend Paper Co.	716	2002	9	NT	FALSE			15.613	14.317	0.000	0.000	14.317	14.317
Port Townsend Paper Co.	716	2002	10	NT	FALSE			15.949	13.827	0.000	0.000	13.827	13.827
Port Townsend Paper Co.	716	2002	11	NT	FALSE			16.014	14.877	0.000	0.000	14.877	14.877
Port Townsend Paper Co.	716	2002	12	NT	FALSE			16.017	14.880	0.000	0.000	14.880	14.880
Port Townsend Paper Co.	716	2003	1	NT	FALSE			15.655	14.450	0.000	0.000	14.450	14.450
Port Townsend Paper Co.	716	2003	2	NT	FALSE			15.854	15.854	0.000	0.000	15.854	15.854
Port Townsend Paper Co.	716	2003	3	NT	FALSE			15.852	14.536	0.000	0.000	14.536	14.536
Port Townsend Paper Co.	716	2003	4	NT	FALSE			16.044	14.712	0.000	0.000	14.712	14.712
Port Townsend Paper Co.	716	2003	5	NT	FALSE			16.270	2.506	0.000	0.000	2.506	2.506
Port Townsend Paper Co.	716	2003	6	NT	FALSE			16.245	14.214	0.000	0.000	14.214	14.214
Port Townsend Paper Co.	716	2003	7	NT	FALSE			16.323	14.968	0.000	0.000	14.968	14.968
Port Townsend Paper Co.	716	2003	8	NT	FALSE			15.654	13.040	0.000	0.000	13.040	13.040
Port Townsend Paper Co.	716	2003	9	NT	FALSE			15.617	14.320	0.000	0.000	14.320	14.320
US DOE (Richland)	404	1998	10	NTP	TRUE	34.494	34.494						
US DOE (Richland)	404	1998	11	NTP	TRUE	31.570	37.446						
US DOE (Richland)	404	1998	12	NTP	TRUE	44.201	47.697						
US DOE (Richland)	404	1999	1	NTP	TRUE	38.997	41.114						
US DOE (Richland)	404	1999	2	NTP	TRUE	33.174	40.478						
US DOE (Richland)	404	1999	3	NTP	TRUE	31.843	36.825						
US DOE (Richland)	404	1999	4	NTP	TRUE	33.163	45.190						
US DOE (Richland)	404	1999	5	NTP	TRUE	36.144	57.038						
US DOE (Richland)	404	1999	6	NTP	TRUE	-5.394	34.500						
US DOE (Richland)	404	1999	7	NTP	TRUE	33.649	34.500						
US DOE (Richland)	404	1999	8	NTP	TRUE	32.564	2.348						
US DOE (Richland)	404	1999	9	NTP	TRUE	30.412	32.849						
US DOE (Richland)	404	1999	10	NTP	TRUE	26.765	33.952						
US DOE (Richland)	404	1999	11	NTP	TRUE	30.322	34.352						
US DOE (Richland)	404	1999	12	NTP	TRUE	31.333	38.953						
US DOE (Richland)	404	2000	1	NTP	TRUE	35.862	40.736						
US DOE (Richland)	404	2000	2	NTP	TRUE	34.143	39.091						
US DOE (Richland)	404	2000	3	NTP	FALSE			32.125	33.841	0.000		29.263	32.125
US DOE (Richland)	404	2000	4	NTP	FALSE			39.517	40.178	0.000		29.485	39.517

Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

(A) Customer	(B) CustNo	(C) Year	(D) Month	(E) Choice	(F) History	(G) Actual Base	(H) Actual Load Shaping	(I) Forecasted System Load, Nominal	(J) Forecasted System Load, CP	(K) Contract CSL, Nominal	(L) Internal Generation, Nominal	(M) Forecast Base	(N) Forecast Load Shaping
US DOE (Richland)	404	2000	5	NTP	FALSE			46.016	42.176	0.000		26.726	46.016
US DOE (Richland)	404	2000	6	NTP	FALSE			31.619	27.419	0.000		-4.287	31.619
US DOE (Richland)	404	2000	7	NTP	FALSE			36.646	41.091	0.000		40.078	36.646
US DOE (Richland)	404	2000	8	NTP	FALSE			2.398	2.638	0.000		36.587	2.398
US DOE (Richland)	404	2000	9	NTP	FALSE			31.291	30.490	0.000		28.228	31.291
US DOE (Richland)	404	2000	10	NTP	FALSE			70.846	66.834	0.000		59.997	70.846
US DOE (Richland)	404	2000	11	NTP	FALSE			74.497	74.497	0.000		64.181	74.497
US DOE (Richland)	404	2000	12	NTP	FALSE			83.133	76.604	0.000		66.555	83.133
US DOE (Richland)	404	2001	1	NTP	FALSE			84.103	85.629	0.000		78.390	84.103
US DOE (Richland)	404	2001	2	NTP	FALSE			85.150	85.150	0.000		72.136	85.150
US DOE (Richland)	404	2001	3	NTP	FALSE			32.228	33.950	0.000		29.357	32.228
US DOE (Richland)	404	2001	4	NTP	FALSE			39.739	40.404	0.000		29.651	39.739
US DOE (Richland)	404	2001	5	NTP	FALSE			46.405	42.532	0.000		26.952	46.405
US DOE (Richland)	404	2001	6	NTP	FALSE			31.876	27.642	0.000		-4.322	31.876
US DOE (Richland)	404	2001	7	NTP	FALSE			36.980	41.466	0.000		40.443	36.980
US DOE (Richland)	404	2001	8	NTP	FALSE			2.399	2.640	0.000		36.612	2.399
US DOE (Richland)	404	2001	9	NTP	FALSE			31.298	30.497	0.000		28.234	31.298
US DOE (Richland)	404	2001	10	NT	FALSE			71.239	67.204	0.000		60.330	71.239
US DOE (Richland)	404	2001	11	NT	FALSE			74.987	74.987	0.000		64.603	74.987
US DOE (Richland)	404	2001	12	NT	FALSE			83.683	77.111	0.000		66.996	83.683
US DOE (Richland)	404	2002	1	NT	FALSE			84.162	85.689	0.000		78.445	84.162
US DOE (Richland)	404	2002	2	NT	FALSE			85.426	85.426	0.000		72.370	85.426
US DOE (Richland)	404	2002	3	NT	FALSE			32.331	34.059	0.000		29.451	32.331
US DOE (Richland)	404	2002	4	NT	FALSE			39.963	40.632	0.000		29.818	39.963
US DOE (Richland)	404	2002	5	NT	FALSE			46.797	42.891	0.000		27.180	46.797
US DOE (Richland)	404	2002	6	NT	FALSE			32.135	27.867	0.000		-4.357	32.135
US DOE (Richland)	404	2002	7	NT	FALSE			37.317	41.843	0.000		40.811	37.317
US DOE (Richland)	404	2002	8	NT	FALSE			2.401	2.642	0.000		36.637	2.401
US DOE (Richland)	404	2002	9	NT	FALSE			31.305	30.503	0.000		28.240	31.305
US DOE (Richland)	404	2002	10	NT	FALSE			71.633	67.576	0.000		60.664	71.633
US DOE (Richland)	404	2002	11	NT	FALSE			75.479	75.479	0.000		65.027	75.479
US DOE (Richland)	404	2002	12	NT	FALSE			84.237	77.622	0.000		67.439	84.237
US DOE (Richland)	404	2003	1	NT	FALSE			84.221	85.749	0.000		78.500	84.221
US DOE (Richland)	404	2003	2	NT	FALSE			85.702	85.702	0.000		72.604	85.702
US DOE (Richland)	404	2003	3	NT	FALSE			32.435	34.168	0.000		29.546	32.435
US DOE (Richland)	404	2003	4	NT	FALSE			40.188	40.860	0.000		29.986	40.188
US DOE (Richland)	404	2003	5	NT	FALSE			47.193	43.254	0.000		27.409	47.193
US DOE (Richland)	404	2003	6	NT	FALSE			32.397	28.094	0.000		-4.392	32.397
US DOE (Richland)	404	2003	7	NT	FALSE			37.657	42.224	0.000		41.183	37.657
US DOE (Richland)	404	2003	8	NT	FALSE			2.403	2.644	0.000		36.663	2.403
US DOE (Richland)	404	2003	9	NT	FALSE			31.311	30.510	0.000		28.246	31.311

Appendix D, Table D3

Some Determinants of Short-term PSW Sales */

(A)	(B)	(C)		(D)	(E)	(F)	(G)	(H)
/------- Model Statistics		-------/		/------- Coefficients				-------/
Regression Statistics		**Forecast Statistics**		**Variable**	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Iterations	1.0	Forecast Observations	0.0	Constant term	803.353	555.386	1.446	14.89%
Adjusted Observations	365.0	Mean Abs. Dev. (MAD)	0.0	CAPACITY	0.111	0.034	3.301	0.11%
Deg. of Freedom for Error	352.0	Mean Abs. % Err. (MAPE)	0.00%	PRICESCMMC	58.412	15.623	3.739	0.02%
R-Squared	0.5	Avg. Forecast Error	0.0	TEMPSPSW	15.496	3.117	4.972	0.00%
Adjusted R-Squared	0.4	Mean % Error	0.00%	**LTCTRCTINT**	**-0.442**	0.222	-1.993	4.70%
Durbin-Watson Statistic	0.5	Root Mean-Square Error	0.0	OCTNOV	-171.870	217.902	-0.789	43.08%
Durbin-H Statistic	#NA	Theil's Inequality Coefficient	0.0	DECJAN	-433.151	203.559	-2.128	3.40%
AIC	12.1	-- Bias Proportion	0.00%	FEBMAR	-650.560	186.569	-3.487	0.06%
BIC	12.3	-- Variance Proportion	0.00%	APRMAY	-710.825	110.246	-6.448	0.00%
F-Statistic	25.7	-- Covariance Proportion	0.00%	JUNJUL	-482.382	81.328	-5.931	0.00%
Prob (F-Statistic)	0.0			TUEWEDTHR	233.290	54.616	4.271	0.00%
Log-Likelihood	-2,714.1			MONFRI	109.525	53.380	2.052	4.09%
Model Sum of Squares	56,044,091			SAT	90.363	77.950	1.159	24.72%
Sum of Squared Errors	64,014,629							
Mean Squared Error	181,860							
Std. Error of Regression	426.5							
Mean Abs. Dev. (MAD)	330.9							
Mean Abs. % Err. (MAPE)	19.62%							
Ljung-Box Statistic	819.2							
Prob (Ljung-Box)	0.0							

*/ An analysis of PBL, Oct. 1997 through Sep. 1998. Col(E) Long-term contract coefficient used in study table TRS 5.

APPENDIX E

Network "Choice" Analysis

Appendix E

Network "Choice" Analysis 1/

		(A)	(B)	(C)	(D)
			Choice		
CUSNO	CUSTOMER	Current	Base	Economic	Agent /2
102	Albion, City of	NT	NT	NT	PBL
301	Alder Mutual Light Co.	NT	NT	NT	
103	Ashland, City of	NTP	NT	NT	
201	Asotin County PUD #1	NT	NT	NT	PBL
104	Bandon, City of	NTP	NT	NT	
203	Benton Cnty PUD	PTP	NT	NT	
303	Benton REA	NT	NT	NT	
306	Big Bend Electric Coop.	NT	NT	NT	PBL
309	Blachly-Lane County Coop.	NT	NT	NT	PNGC
106	Blaine	NTP	NT	NT	
107	Bonners Ferry (City)	NTP	NT	NT	
109	Burley, City of	NT	NT	PTP	PBL
111	Canby Utility Board	NTP	NT	NT	
115	Cascade Locks, City of	NTP	NT	NT	
312	Central Elec Coop, Inc.	NT	NT	NT	PNGC
207	Central Lincoln PUD	NT	NT	NT	
313	CENTRAL MONTANA ELECTRIC COOP	NT	NT	PTP	
119	Centralia, City of	NT	NT	NT	
210	Chelan County PUD #1	NTP	STP	PTP	
123	Cheney, City of	NT	NT	NT	
124	Chewelah, City of	NT	NT	NT	PBL
213	Clallam County PUD #1	NT	NT	NT	
216	Clark Public Utilities	NT	NT	NT	PPL
219	Clatskanie PUD	PTP	PTP	PTP	
315	Clearwater Power Co.	NT	NT	NT	
318	Columbia Basin Elec Coop	NT	NT	PTP	PBL
321	Columbia Power Coop	NT	NT	NT	PBL
324	Columbia REA	NT	NT	NT	PBL
221	Columbia River PUD	NT	NT	PTP	
192	Consolidated Irrigation Dist	NTP	NT		
327	Consumer's Power, Inc.	NT	NT	NT	PNGC
330	Coos-Curry Electric Coop.	NT	NT	NT	PNGC
125	Coulee Dam (City of)	NT	NT	NT	PBL
222	Cowlitz County PUD	NTP	NT	PTP	
127	Declo, City of	NT	NT	NT	PBL
226	Douglas County PUD # 1	PTP	PTP	PTP	
333	Douglas Electric Coop.	NT	NT	NT	PNGC
128	Drain, City of	NTP	NT	PTP	
335	East End Mutual Co.	NT	NT	NT	PBL
131	Eatonville, Town of	NT	NT	NT	
133	Ellensburg, City of	NT	NT	PTP	
334	Elmhurst Mutual	NT	NT	NT	
229	Emerald PUD	NTP	PTP	NT	
841	ENERGY NW INC., (FEC)	NT	NT		
137	Eugene Water and Electric Board	NTP	PTP	NT	
337	Fall River Rural Elec Coop	NT	NT	NT	PBL
338	Farmers' Elec Company	NT	NT	NT	PBL
230	Ferry County PUD #1	NT	NT	NT	PBL
140	Fircrest, City of	NT	NT	NT	
339	Flathead Electric Coop., Inc.	NTP	NT	NT	
142	Forest Grove, City of	NTP	NT	NT	
233	Franklin Cnty PUD	PTP	NT	NT	

Appendix E

Network "Choice" Analysis 1/

		(A)	(B)	(C)	(D)
			Choice		
CUSNO	CUSTOMER	Current	Base	Economic	Agent /2
340	Glacier Electric Coop., Inc.	NT	NT	NT	
238	Grant County PUD #2	NTP	PTP	PTP	
241	Grays-Harbor County PUD	PTP	PTP	PTP	
341	Harney Elec Coop, Inc.	NT	NT	NT	PBL
150	Heyburn, City of	NT	NT	PTP	PBL
342	Hood River Elec Coop	NT	NT	NT	PBL
345	Idaho County Light & Power	NT	NT	NT	
152	Idaho Falls, City of	PTP	PTP	PTP	
348	Inland Power & Light Co.	NT	NT	NT	
246	Kittitas County PUD #1	NTP	NT	NT	
250	Klickitat Cnty	PTP	PTP	PTP	
351	Kootenai Electric Coop., Inc.	NT	NT	NT	
353	Lakeview Light & Power Co.	NT	NT	NT	
354	Lane Electric Coop., Inc.	NT	NT	NT	PNGC
253	Lewis County PUD #1	NT	NT	PTP	
357	Lincoln Electric Coop. - MT	NT	NT	NT	
358	Lincoln Electric Coop.-WA	NT			
359	Lost River Elec Coop, Inc.	NT	NT	NT	PNGC
360	Lower Valley Power & Light	NT	NT	NT	
257	Mason County PUD #1	NT	NT	NT	
258	Mason County PUD #3	NT	NT	NT	
154	McCleary, City of	NT	NT	PTP	
155	McMinnville, City of	NT	NT	NT	
361	Midstate Elec Coop, Inc.	NT	NT	NT	PBL
158	Milton, City of	NT	NT	NT	
159	Milton-Freewater, City of	NT	NT	NT	
161	Minidoka, City of	NT	NT	NT	PBL
364	Missoula Electric Coop.	NT	NT	NT	
366	Modern Electric Co.	NT	NT	PTP	PBL
163	Monmouth, City of	NTP	NT	NT	
817	NATIONAL ENERGY SYSTEMS COMPANY	PTP	PTP		
367	Nespelem Valley Elec. Coop.	NT	NT	NT	PBL
370	Northern Lights, Inc.	NT	NT	NT	PNGC
262	Northern Wasco County PUD	NT	NT	NT	
372	Ohop Mutual Light Co.	NT	NT	NT	
373	Okanogan County Elec. Coop.	NTP	NT	NT	PBL
266	Okanogan County PUD	NTP	NT	NT	
376	Orcas Power & Light Co.	NT	NT	NT	
371	Oregon Trail Elec Coop	NT	NT	PTP	PNGC
270	Pacific County PUD #1	NT	NT	NT	
375	Parkland Light & Water Co.	NT	NT	NT	
273	Pend Oreille PUD #1	NTP	NT	NT	
374	Peninsula Light Co., Inc.	NT	NT	NT	
167	Plummer, City of	NT	NT	NT	PBL
170	Port Angeles City Light	NT	NT	NT	
716	PORT TOWNSEND PAPER CORPORATION	NTP	NT	PTP	
379	Raft River Rural Elec Coop.	NT	NT	NT	PNGC
380	Ravalli County Electric Coop.	NTP	NT	NT	
175	Richland, City of	PTP	NT	NT	
381	Riverside Elec Company, Ltd.	NT	NT	NT	PBL
177	Rupert, City of	NT	NT	NT	PBL
382	Rural Elec Company	NT			PBL

Appendix E

Network "Choice" Analysis 1/

		(A)	(B)	(C)	(D)
			Choice		
CUSNO	CUSTOMER	Current	Base	Economic	Agent /2
383	Salem Electric	NT	NT	PTP	PBL
384	Salmon River Elec	NTP	NT	NT	
180	Seattle City Light	PTP	PTP	PTP	
279	Skamania County PUD	NT	NT	NT	PBL
283	Snohomish County PUD	PTP	PTP	PTP	
181	Soda Springs, City of	NT	NT	PTP	PBL
385	South Side Elec Lines, Inc.	NT	NT	NT	PBL
184	Springfield Utility Board	PTP	PTP	PTP	
185	Steilacom, Town of	NT	NT	NT	
186	Sumas, City of	NTP	NT	PTP	
386	Surprise Valley Elec. Corp.	NT	NT	NT	PBL
188	Tacoma Public Utilities	NTP	PTP	PTP	
387	Tanner Electric Coop.	NTP	NT	NT	
288	Tillamook People's Util. Dist.	NT	NT	NT	
189	Troy, City of	NTP	NT	NT	
430	U.S. AIR FORCE (FAIRCHILD)	NT	NT	PTP	PBL
490	U.S. DEPARTMENT OF NAVY (BANGOR)	NTP	NT	PTP	
491	U.S. DEPARTMENT OF NAVY (JIM CREEK)	NTP	NT	PTP	
451	U.S. DEPARTMENT OF NAVY (PUGET SOUN	NTP	NT	NT	
482	U.S.B.I.A.- Wapato	NT	NT	NT	PBL
388	Umatilla Elec Coop	NT	NT	NT	PNGC
311	UNITED ELECTRIC COOP	NT	NT	NT	PBL
389	Unity Light & Power	NT			PBL
410	US BUREAU OF MINES	NTP	NT	NT	
405	US DEPT OF ENERGY (300 AREA)	NTP	NT	PTP	
404	US DEPT OF ENERGY (RICHLAND)	NTP	NT		
499	USBIA- Mission Valley	NT	NT		
483	USBIA-MISSION VALLEY POWER	NT	NT	NT	
498	USBIA-Wapato	NT	NT		
472	USBR, YAKIMA PROJECT (ROZA)	NT	NT	NT	
695	VANALCO	PTP	PTP		
191	Vera Water & Power	NT	NT	NT	
390	Vigilante Electric Coop.	NT	NT	NT	
293	Wahkiakum County PUD	NT	NT	NT	
394	Wasco Elec Coop	NT	NT	NT	PBL
195	WASHINGTON PUBLIC POWER SUPPLY SYST	NTP	NT	NT	
396	Wells Rural Elec Company	NT	NT	PTP	
397	West Oregon Electric Coop.	NTP	NT	NT	
298	Whatcom County PUD #1	NT	NT	NT	

1/ Column (A), Current Choice, is the Customer's current service.
Column (B), Base Choice, is the service assumed for the FY 2002/03 rate period.
Column (C), is the result of the economic analysis.

2/ Note: PBL's agency is assocated with the current rate period.

APPENDIX F

FPT-02 Revenue Forecast

Appendix F
FPT-02 Revenue Forecast

				Demand (MW)			Main Grid						Secondary System					POD Rate	Compensation Factors		Project
			Contr								Interc		Interc	Interm		Interm	Priest	Factors			Revenues
Company	Resource	POD Name	No.	POD	Project	Wght	Term1	Miles	Misc	Term2	Term	Txf	Term	Term 1	Miles	Term 2	Rapids	$/kW-yr	$/kW-mo	$/kW-yr	$000/yr
Avista	WNP-3	Westside	92186	32.2	32.2	1.000	1.0	284.4	1.0	1.0	1.0							21.001	1.750	21.001	676.6
	Avista System (GTA)	Colbert Tap	91970	15.1	65.3	0.231							1.0	1.0	7.9			1.732			
		Deer Park	91970	11.1	65.3	0.170							1.0	1.0	17.4			2.072			
		Loon Lake	91970	4.4	65.3	0.067							1.0	1.0	22.3			0.984			
		Milan	91970	7.7	65.3	0.118							1.0	1.0	15.4			1.314			
		Noxon	91970	0.1	65.3	0.002									0.2			0.000			
		Priest River	91970	14.9	65.3	0.228								1.0	6.6	1.00		1.702			
		Spirit	91970	4.1	65.3	0.063							1.0	1.0	32.6			1.237			
		Wilbur	91970	7.9	65.3	0.121								1.0	18.0			1.332	0.864	10.372	676.8
Cowlitz Co PUD	Priest Rapids	Longview 69	13520	17.0	17.0	1.000	1.0	151.5	1.0	1.0	0.5						-0.2190	12.835	1.070	12.835	218.3
	Swift	Longview 69	92043	77.0	77.0	1.000		21.4	1.0	1.0	0.5							4.948	0.412	4.948	380.7
	Wanapum	Longview 69	00025	21.0	21.0	1.000	1.0	154.3	1.0	1.0	0.5							13.215	1.101	13.215	277.5
Douglas Co PUD	Nilles Corner	Nilles Corner	90066	1.9	1.9	1.000									12.4			6.134	0.511	6.134	11.7
	Wells	Columbia 115	92389	4.7	4.7	1.000						1.0	1.0					6.890	0.574	6.890	32.4
Okanogan Co PUD	Wells	East Omak 115	90013	0.0	0.0	0.640		72.0	1.0			1.0	1.0					8.908			
	Wells	Tonasket 115	90013	0.0	0.0	0.360		72.0	1.0			1.0		1.0	20.3			8.855	1.480	17.763	0.0
PacifiCorp	Centralia	Load Center	09228	638.0	638.0	1.000	1.0	51.0	1.0	1.0	1.0							7.500	0.625	7.500	4,785.0
	Clatsop	Clatsop	14612	5.7	7.0	0.814	1.0	80.4	1.0	1.0		1.0						11.474			
		Astoria	14612	1.3	7.0	0.186							1.0	1.0	57.9			5.982			
		Tillamook	14612	0.0	7.0	0.000							2.0	1.0	67.3	1.00		0.000	1.455	17.456	122.2
	Colstrip	Flathead	90168	14.0	140.0	0.100	1.0	136.8	1.0	1.0								1.194			
		Trumbull	90168	14.0	140.0	0.100	1.0	141.5	1.0									1.164			
		Lion Mt	90168	15.0	140.0	0.107	1.0	126.9	1.0									1.156			
		Buckley	90168	70.0	140.0	0.500	1.0	414.9	1.0	1.0								14.015			
		Libby	90168	1.0	140.0	0.007	1.0	172.3	1.0	1.0		1.0		1.0	12.3			0.197			
		Columbia Falls	90168	13.0	140.0	0.093	1.0	172.3	1.0	1.0		1.0		1.0	12.3			2.561			
		Kalispell	90168	13.0	140.0	0.093	1.0	172.3	1.0	1.0		1.0		1.0	12.3			2.561	1.904	22.848	3,198.7
	Hermiston	Alvey	94316	420.0	490.0	0.857	1.0	224.9	1.0									14.108			
		Buckley	94316	70.0	490.0	0.143	1.0	70.0	1.0									1.071	1.265	15.179	7,438.2
	Midpoint-Medford	Roundup	94333	55.0	600.0	0.092	1.0	39.8	1.0	1.0		1.0	1.0					1.212			
		Alvey	94333	145.0	600.0	0.242	1.0	259.9	1.0									4.467			
		Alvey	94333	241.0	600.0	0.402	1.0	224.9	1.0									6.611			
		McNary 69	94333	35.0	600.0	0.058			1.0			1.0	1.0					0.569			
		Santiam	94333	40.0	600.0	0.067	1.0	182.0	1.0	1.0			1.0	1.0				1.209			
		Albany	94333	84.0	600.0	0.140	1.0	206.5	1.0	1.0		1.0	1.0					3.201	1.439	17.269	10,360.8
	Priest Rapids	Midway 230	90100	150.0	235.0	0.638			1.0									1.832			
		Outlook	90100	85.0	235.0	0.362	1.0	22.1	1.0									1.710	0.295	3.542	831.9
	PSW(DC)/PPL	Alvey	94280	200.0	200.0	1.000	1.0	27.6	1.0									5.047	0.421	5.047	1,010.4
	Swift	Troutdale	92269	222.0	222.0	1.000		28.9	1.0	1.0	0.5							5.382	0.448	5.382	1,193.5
	Wanapum	Troutdale	26811	269.0	269.0	1.000	1.0	149.0	1.0	1.0	0.5							12.909	1.076	12.909	3,473.3
	Widco	Centralia	92325	17.3	17.3	1.000	1.0	83.5	1.0	1.0	0.5							9.120	0.760	9.120	157.8
Pend Oreille Co PUD	Boundary POI	Usk	92488	36.0	36.0	1.000	1.0	49.0	1.0	0.5	0.5							6.834	0.570	6.834	246.2
	Box Canyon	Newport	90006	0.0	0.0	0.278								1.0	2.1			0.870			
		Sacheen	90006	0.0	0.0	0.066		7.8						1.0	13.9	1.00		0.762			
		Metaline Falls	90006	0.0	0.0	0.116												0.000			
		Diamond Lake	90006	0.0	0.0	0.043									8.3	1.00		0.267			
		Usk	90006	0.0	0.0	0.497	1.0		1.0	1.0		1.0		1.0	13.9	1.00		10.180	1.007	12.079	0.0
PGE	Boardman Unit 1	John Day	92260	75.0	75.0	1.000	1.0	28.3	1.0	1.0	1.0							6.187	0.516	6.187	464.4
	WNP-3	Keeler	92187	53.7	53.7	1.000	1.0	101.6	1.0	1.0	2.0							10.947	0.912	10.947	587.7

Appendix F
FPT-02 Revenue Forecast

Company	Resource	POD Name	Contr No.	Demand (MW) POD	Demand (MW) Project	Wght	Main Grid Term1	Main Grid Miles	Main Grid Misc	Main Grid Term2	Main Grid Interc Term	Txf	Secondary System Interc Term	Secondary System Interm Term 1	Secondary System Miles	Secondary System Interm Term 2	Priest Rapids	POD Rate Factors $/kW-yr	Compensation Factors $/kW-mo	Compensation Factors $/kW-yr	Project Revenues $000/yr
Power Resources	Boardman	John Day	94151	50.0	50.0	1.000	1.0	28.3	1.0	1.0								5.667			
Coop (PNGC)		Slatt	94151	0.0	50.0	0.000												0.000	0.472	5.667	283.2
Puget Sound P&L	WNP-3	Maple Valley	92185	32.2	32.2	1.000	1.0	69.4	1.0	1.0	2.0							9.084	0.757	9.084	292.5
Tacoma PU	Priest Rapids	Cowlitz	13512	71.1	71.1	1.000	1.0	128.5	1.0								-0.2370	10.646	0.887	10.646	756.8
	Centralia	Cowlitz	94304	0.0	0.0	1.000		38.1	1.0	1.0								5.654	0.471	5.654	0.0
	NFP	John Day	93936	49.3	49.3	1.000	1.0	130.0	1.0									10.970	0.914	10.970	540.2
Total FPT.1				2,672																	32,134
Total FPT.3				733																	5,882
Total FPT				3,405																	38,017

APPENDIX G

DSI Delivery Charge Revenue

Appendix G
DSI Delivery Charge Revenue

		(A)	(B)	(C)	(D)	(E)	(F)
	Summary of UFT Sole Use Charges (from Contracts in place as of 2/1/2000)					Projected O&M 2/	
	DSI Facility 1/	Investment	I&A	O&M	Total	2,002.0	2,003.0
		($)	($)	($)	($)	($)	($)
1	ALCOA (Addy)	2,894,264	233,857	44,750	278,607	48,945	51,331
2	ALCOA (Intalco)	5,970,595	485,409	139,968	625,377	153,090	160,552
3	ALCOA (Valhalla)	3,622,454	294,506	91,900	386,406	100,516	105,415
4	Atochem (Penwalt)	2,471,406	199,059	252,075	451,135	252,075	266,903
5	Goldendale Aluminum (Harvalum)	4,244,203	345,054	95,460	440,514	104,409	109,498
6	NW Aluminum (Harvey)	1,790,953	145,604	45,188	190,792	49,424	51,833
7	Reynolds (Longview)	22,196,629	1,793,488	238,174	2,031,662	260,503	273,200
8	Reynolds (Troutdale)	14,753,547	1,192,087	193,860	1,385,947	212,034	222,369
9	**TOTAL**	**57,944,051**	**4,689,063**	**1,101,375**	**5,790,438**	**1,180,996**	**1,241,101**
10	Average ACR		8.09%				

1/ Excludes facilities projected to be sold
2/ O&M projections based upon the projected 3 year average levels as applied to the year the UFT components were last updated

APPENDIX H

Monthly Transmission Revenue

Appendix H

Monthly Transmission Revenue
FY 2002, ($000)

	FY 2002 Service	Rate	(A) Oct-01	(B) Nov-01	(C) Dec-01	(D) Jan-02	(E) Feb-02	(F) Mar-02	(G) Apr-02	(H) May-02	(I) Jun-02	(J) Jul-02	(K) Aug-02	(L) Sep-02	(M) FY 2002
	General Transmission														
1	Formula Power Transmission	FPT-02	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	**38,017**
2	Integration of Resources	IR-02	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	**68,315**
3	Network Transmission, Base	NT-02	5,055	5,112	6,142	6,373	6,354	5,157	4,650	4,249	4,068	4,476	4,587	4,199	**60,421**
4	Network Transmission, Load Shaping	NT-02	2,238	2,289	2,692	2,766	2,790	2,269	2,023	1,911	1,836	1,917	1,978	1,848	**26,556**
5	Point to Point, Long-term Contracts	PTP-02	12,644	12,555	12,555	12,560	12,560	12,833	12,856	12,960	12,988	12,825	12,661	12,661	**152,657**
6	Point to Point, Daily Block 1	PTP-02	402	269	400	1,372	646	784	544	545	681	840	585	406	**7,474**
7	Point to Point, Daily Block 2	PTP-02	635	710	1,351	3,496	1,886	2,424	1,984	2,098	2,176	2,509	2,344	1,221	**22,834**
8	Point to Point, Hourly	PTP-02	797	799	1,408	3,858	2,203	2,569	2,099	2,139	2,357	2,677	2,375	1,338	**24,620**
9	**Subtotal General Rates, Network**		**30,632**	**30,595**	**33,408**	**39,285**	**35,300**	**34,897**	**33,017**	**32,763**	**32,968**	**34,105**	**33,391**	**30,534**	**400,894**
10	Southern Intertie, Long-term Contracts	IS-02	3,994	3,892	3,854	3,854	3,854	3,854	4,311	5,261	5,409	5,425	5,425	4,055	**53,188**
11	Southern Intertie, Daily Block 1	IS-02	169	114	103	462	39	151	274	63	147	646	382	223	**2,775**
12	Southern Intertie, Daily Block 2	IS-02	305	194	258	1,016	450	696	1,411	1,501	1,486	2,079	2,199	884	**12,479**
13	Southern Intertie, Hourly	IS-02	158	104	123	498	188	297	605	569	599	939	912	393	**5,385**
14	**Subtotal General Rates, Southern Intertie**		**4,626**	**4,304**	**4,337**	**5,830**	**4,530**	**4,998**	**6,602**	**7,394**	**7,642**	**9,089**	**8,919**	**5,556**	**73,826**
15	Montana Intertie	IM-02	0	0	0	0	0	0	0	0	0	0	0	0	**0**
16	Intertie East	IE-02	0	0	0	0	0	0	0	0	0	0	0	0	**0**
17	Utility Delivery Charge	Delv	767	763	911	894	914	807	756	700	649	675	678	646	**9,161**
18	DSI Delivery Charge	Delv	483	483	483	483	483	483	483	483	483	483	483	483	**5,790**
19	**Subtotal General Transmission Rates**		**36,507**	**36,145**	**39,139**	**46,492**	**41,227**	**41,183**	**40,858**	**41,339**	**41,741**	**44,352**	**43,470**	**37,219**	**489,672**
	Other														
20	Annual Cost Rate		115	115	115	115	115	115	115	115	115	115	115	115	**1,375**
21	Columbia Storage Power Exchange		24	24	24	24	24	24	21	21	21	21	21	21	**268**
22	Fiber		1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	**15,500**
23	Fiber Depreciation		58	58	58	58	58	58	58	58	58	58	58	58	**696**
24	Generation Integration		614	614	614	614	614	614	614	614	614	614	614	614	**7,369**
25	Irrigation Pumping Power		0	0	0	0	0	0	129	258	258	258	258	129	**1,288**
26	Nonfederal Participation Depreciation		278	278	278	278	278	278	278	278	278	278	278	278	**3,335**
27	Operations and Maintenance		59	29	0	0	0	29	29	147	117	117	88	59	**675**
28	Personal Communications Wireless		339	339	339	339	339	339	339	339	339	339	339	339	**4,070**
29	Power Factor Penalty Charge		421	431	507	521	525	427	381	360	346	361	372	348	**5,000**
30	Remedial Action Scheme		50	50	50	50	50	50	50	50	50	50	50	50	**597**
31	Reservation Fee		69	69	69	69	69	69	69	69	69	69	69	69	**828**
32	Supplemental Capacity Wheeling		5	5	5	5	5	5	5	5	5	5	5	5	**62**
33	Townsend Garrison Transmission		845	845	845	845	845	845	845	845	845	845	845	845	**10,136**
34	Use of Facilities		473	473	473	473	473	473	473	473	473	473	473	473	**5,679**
35	**Subtotal Other Transmission**		**4,641**	**4,621**	**4,668**	**4,682**	**4,686**	**4,618**	**4,697**	**4,922**	**4,879**	**4,894**	**4,876**	**4,693**	**56,877**
	Ancillary														
36	Scheduling Control & Dispatch		3,825	3,763	4,149	5,270	4,457	4,534	4,492	4,576	4,658	5,027	4,873	3,987	**53,609**
37	Generation Supplied Reactive		1,462	1,436	1,577	2,019	1,697	1,744	1,736	1,774	1,809	1,951	1,890	1,540	**20,633**
38	Regulation & Frequency Response		1,378	1,365	1,659	1,703	1,553	1,398	1,206	1,178	1,095	1,182	1,219	1,102	**16,038**
39	Energy Imbalance		0	0	0	0	0	0	0	0	0	0	0	0	**0**
40	Operating Reserves - Spinning		1,632	1,617	1,965	2,018	1,839	1,656	1,429	1,395	1,297	1,400	1,444	1,305	**18,996**
41	Operating Reserves - Supplemental		1,632	1,617	1,965	2,018	1,839	1,656	1,429	1,395	1,297	1,400	1,444	1,305	**18,996**
42	**Subtotal Ancillary Services**		**9,927**	**9,798**	**11,313**	**13,028**	**11,386**	**10,988**	**10,291**	**10,319**	**10,155**	**10,959**	**10,868**	**9,238**	**128,273**
43	**Total Revenue FY 2002**		**51,076**	**50,564**	**55,120**	**64,201**	**57,300**	**56,789**	**55,846**	**56,580**	**56,775**	**60,205**	**59,215**	**51,151**	**674,822**

Appendix H

Monthly Transmission Revenue
FY 2003, ($000)

	FY 2003 Service	Schedule	(A) Oct-02	(B) Nov-02	(C) Dec-02	(D) Jan-03	(E) Feb-03	(F) Mar-03	(G) Apr-03	(H) May-03	(I) Jun-03	(J) Jul-03	(K) Aug-03	(L) Sep-03	(M) FY 2003
	General Transmission														
1	Formula Power Transmission	FPT-02	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	**38,017**
2	Integration of Resources	IR-02	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	5,693	**68,315**
3	Network Transmission, Base	NT-02	5,124	5,193	6,235	6,459	6,448	5,231	4,731	4,329	4,145	4,559	4,666	4,271	**61,392**
4	Network Transmission, Load Shaping	NT-02	2,263	2,319	2,727	2,799	2,827	2,299	2,050	1,938	1,861	1,944	2,004	1,871	**26,901**
5	Point to Point, Long-term Contracts	PTP-02	13,478	13,389	13,389	13,201	13,201	13,201	13,758	13,862	13,891	13,638	13,622	13,622	**162,253**
6	Point to Point, Daily Block 1	PTP-02	414	279	411	1,431	679	818	527	526	658	820	557	383	**7,502**
7	Point to Point, Daily Block 2	PTP-02	655	734	1,389	3,645	1,982	2,528	1,921	2,026	2,101	2,451	2,231	1,150	**22,813**
8	Point to Point, Hourly	PTP-02	822	827	1,448	4,023	2,315	2,680	2,032	2,066	2,276	2,615	2,260	1,260	**24,624**
9	**Subtotal General Rates, Network**		**31,617**	**31,602**	**34,461**	**40,420**	**36,312**	**35,617**	**33,880**	**33,608**	**33,793**	**34,888**	**34,202**	**31,418**	**411,817**
10	Southern Intertie, Long-term Contracts	IS-02	4,006	3,904	3,865	3,633	3,633	3,633	3,633	4,215	4,248	4,226	4,226	3,800	**47,023**
11	Southern Intertie, Daily Block 1	IS-02	168	113	102	522	41	161	320	78	187	805	467	238	**3,203**
12	Southern Intertie, Daily Block 2	IS-02	303	193	256	1,148	474	741	1,648	1,861	1,881	2,589	2,688	943	**14,725**
13	Southern Intertie, Hourly	IS-02	157	104	122	563	198	316	707	705	758	1,169	1,114	420	**6,333**
14	**Subtotal General Rates, Southern Intertie**		**4,634**	**4,313**	**4,345**	**5,867**	**4,346**	**4,851**	**6,309**	**6,860**	**7,074**	**8,788**	**8,496**	**5,402**	**71,284**
15	Montana Intertie	IM-02	0	0	0	0	0	0	0	0	0	0	0	0	**0**
16	Intertie East	IE-02	0	0	0	0	0	0	0	0	0	0	0	0	**0**
17	Utility Delivery Charge	Delv	776	772	922	905	925	816	765	708	656	683	686	653	**9,268**
18	DSI Delivery Charge	Delv	483	483	483	483	483	483	483	483	483	483	483	483	**5,790**
19	**Subtotal General Transmission Rates**		**37,509**	**37,170**	**40,211**	**47,674**	**42,066**	**41,767**	**41,436**	**41,658**	**42,005**	**44,841**	**43,866**	**37,956**	**498,159**
	Other														
20	Annual Cost Rate		115	115	115	115	115	115	115	115	115	115	115	115	**1,375**
21	Columbia Storage Power Exchange		21	21	21	21	21	21	0	0	0	0	0	0	**127**
22	Fiber		1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	**17,500**
23	Fiber Depreciation		58	58	58	58	58	58	58	58	58	58	58	58	**696**
24	Generation Integration		603	603	603	603	603	603	603	603	603	603	603	603	**7,235**
25	Irrigation Pumping Power		0	0	0	0	0	0	129	258	258	258	258	129	**1,288**
26	Nonfederal Participation Depreciation		278	278	278	278	278	278	278	278	278	278	278	278	**3,335**
27	Operations and Maintenance		59	29	0	0	0	29	29	147	117	117	88	59	**675**
28	Personal Communications Wireless		369	369	369	369	369	369	369	369	369	369	369	369	**4,430**
29	Power Factor Penalty Charge		421	431	507	521	525	427	381	360	346	361	372	348	**5,000**
30	Remedial Action Scheme		50	50	50	50	50	50	50	50	50	50	50	50	**597**
31	Reservation Fee		138	138	138	138	138	138	138	138	138	138	138	138	**1,656**
32	Supplemental Capacity Wheeling		5	5	5	5	5	5	0	0	0	0	0	0	**27**
33	Townsend Garrison Transmission		845	845	845	845	845	845	845	845	845	845	845	845	**10,136**
34	Use of Facilities		473	473	473	473	473	473	473	473	473	473	473	473	**5,679**
35	**Subtotal Other Transmission**		**4,892**	**4,873**	**4,919**	**4,933**	**4,938**	**4,869**	**4,926**	**5,151**	**5,107**	**5,123**	**5,105**	**4,922**	**59,755**
	Ancillary														
36	Scheduling Control & Dispatch		3,979	3,923	4,320	5,473	4,598	4,639	4,595	4,642	4,715	5,117	4,950	4,109	**55,062**
37	Generation Supplied Reactive		1,526	1,502	1,648	2,108	1,757	1,790	1,780	1,804	1,835	1,991	1,924	1,591	**21,257**
38	Regulation & Frequency Response		1,345	1,333	1,620	1,664	1,517	1,366	1,178	1,151	1,069	1,154	1,190	1,076	**15,663**
39	Energy Imbalance		0	0	0	0	0	0	0	0	0	0	0	0	**0**
40	Operating Reserves - Spinning		1,538	1,524	1,852	1,901	1,734	1,561	1,347	1,315	1,222	1,319	1,361	1,230	**17,903**
41	Operating Reserves - Supplemental		1,537	1,523	1,850	1,900	1,732	1,560	1,346	1,314	1,221	1,318	1,360	1,229	**17,889**
42	**Subtotal Ancillary Services**		**9,925**	**9,804**	**11,290**	**13,046**	**11,338**	**10,915**	**10,246**	**10,225**	**10,064**	**10,899**	**10,785**	**9,235**	**127,773**
43	**Total Revenue FY 2003**		**52,326**	**51,847**	**56,420**	**65,653**	**58,342**	**57,551**	**56,607**	**57,035**	**57,176**	**60,863**	**59,755**	**52,112**	**685,687**

APPENDIX I

Power Factor Penalty Charge

Appendix I

Power Factor Penalty Charge

Rate Calculation

		Capacitors	Reactors
	Installed Reactive and Associated Capital Investment	(lagging reactive)	(leading reactive)
1	Total Installed kVAr	13,975,150	6,441,000
2	Capital Investment	$240,832,704	$107,692,655
	Annual Costs		
3	Annual Cost Ratio	7.85%	7.85%
4	Annual Cost of Interest And Amortization	$18,905,367	$8,453,873
5	Annual Cost of O&M	$4,154,498	$1,231,520
6	Total Annual Cost	$23,059,865	$9,685,393
7	**Calculation of Rate**		
8	Annual Cost per kVAr	$1.65	$1.50
9	Monthly Cost per kVAr	$0.14	$0.12
10	Power Factor Penalty Rate ($/kVAr-mo) 1/	**$0.28**	**$0.24**

Revenue Forecast

		Current 2/	Proposed 3/
	Rate		
11	Lagging Reactive Demand during HLHs: ($/kVAr/month)	0.08	0.28
12	Leading Reactive Demand during LLHs: ($/kVAr/month)	0.06	0.24
13	Reactive Energy (mills/kVArh	0.53	N/A
	Revenues		
14	Demand Charge - Lagging	$1,045	$4,000
15	Demand Charge - Leading	$288	$1,000
16	Energy Charge	$133	$0
17	Total	$1,466	$5,000

1/ The proposed rate is the monthly cost per kVAr doubled to reflect the penalty nature of the charge.
2/ Current revenues are for FY99.
3/ Based on an analysis of several customers, estimate that revenue will increase approximately 25% due to the change from a deadband which is based on a 0.95 power factor to one based on a 0.97 power factor.
Assumed also a 15 to 20 percent reduction in revenues as customers reduce their reactive demand due to the proposed penalty charge.

Bonneville Power Administration

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