Load Shaping

The load shaping product provides purchasers with the ability to deviate from their forecasted BPA purchases because of deviations between forecasted and actual retail load. With this product, the customer pays for only the amount of power delivered, at the applicable rate. BPA proposes to offer four load shaping products: Full Load Shaping, Partial Load Shaping, Industrial Exemption, and DSI Load Shaping. The studies for Industrial Exemption and DSI Load Shaping follow the study for Full and Partial Load Shaping.

Full Load Shaping covers all deviations between forecasted and actual retail loads. Partial Load Shaping allows the customer to select a MW amount of protection for fluctuations between forecasted and actual retail load to be covered by BPA. Industrial Exemption allows a customer to exclude certain industrial loads from Full Load Shaping. With the Industrial Exemption product, the purchaser will pay a premium for positive deviations between forecast and actual load and a charge for revenue losses due to negative deviations from the forecast amount of the exempt load. DSI Load Shaping assures that a customer may vary monthly energy deliveries up to 15 percent above or below that month's energy nomination. As long as energy deliveries fluctuate within this band for a given month, the customer will be relieved of the take-or-pay obligation on the variations below that month's nomination. Likewise, the customer is assured of paying the contract rate for energy variations not exceeding 15 percent above that month's nomination.

Methodology

FULL LOAD SHAPING

The methodology approximates the amount of incremental or marginal cost risk BPA must bear in providing the load shaping product on a firm basis. Estimates of the risk were based on probabilities of BPA sales varying from forecast due to variations from forecast of the purchaser's retail load. All calculations were done in nominal dollars, unless stated otherwise below.

Energy:
Preliminary seasonal and diurnal PF rates derived from the 1996 rate case Marginal Cost Analysis were used to estimate BPA's PF rates, using an assumed average PF rate for all power purchases for utility customers of 24.4 mills per kWh (See Table D). The study was prepared prior to final PF rates being available. These seasonal and diurnal rate estimates are shown in Table D.

The Load Shaping study selected from the Risk Analysis, for each month of the rate period, the medium load forecast. The medium load forecast was reduced for 700 MWs of industrial exemptions and reduced by Tacoma' s load. The Load Shaping study selected from the Risk Analysis, for each month of the rate period, the positive and negative deviations from the medium load forecast of total retail load associated with economic conditions that had 30% and 10% probabilities of occurrence, and assumed 20% probability of zero deviation. Positive and negative deviations for five weather conditions with the same probability distribution were determined. This yields 25 joint probability distributions for each month for the study, and resulting amounts of load deviation. (See Table A, fn. 6&8).

Each of the 25 deviations for each diurnal period during each month were added to the amount of BPA planned purchases from NFRAP in the case of positive total deviations, or added as the next increment of sales to the Pacific Southwest from NFRAP in the case of negative total deviations. The purchase quantities (positive deviations) associated with those 25 deviations were inserted into the total purchase rate equation (See Table C). The sales quantities (negative deviations) associated with the 25 deviations were inserted into the total sales equations (See Table F), resulting in the next lower nonfirm sale price. As described in our supplemental direct and rebuttal testimony the purchase and sale equations have been changed for the final Load Shaping Analysis to be based on the Marginal Cost Analysis

The study next calculates the difference between the incremental purchase cost in the case of positive deviations, or next lower nonfirm sale price in the case of negative deviations, and the estimated PF rate for each month and diurnal period. Negative differences are benefits to BPA and positive differences are costs to BPA. The quantity of each of the 25 deviations is converted to a percent of the medium load forecast and that percent is multiplied by the probability of the economic condition, the probability of the weather condition, and the difference between the PF rate and the incremental cost or decremental revenues for that deviation. The results are summed by diurnal period and month and weighted in proportion to the number of heavy and light load hours (See Tables FY97 - FY01 fn 8), to develop a cost per kilowatt-hour of medium forecast load. The results are converted to present value by month for the rate period using a 7.8% discount rate (See Table G).

Demand:

The deviation in peak demand was assumed to be proportional to the energy deviation. The proportionate amount of deviation associated with worst case weather conditions in each month is added to the proportionate amount of deviation associated with each economic scenario. These deviations were multiplied by the probability of each economic scenario (See Table E fn 4). This product was multiplied by the value of capacity, from BPA' s rate proposal, by month as shown in Table E, which is $0.87 per kW-mo., for the 5 year rate period. These probability weighted costs were summed across the five economic scenarios to get an expected cost by month for the rate period. Each of the monthly costs were then divided by the number of hours in each month to get a mills per kWh cost. These costs were converted to present value by month over the 5 year period at a 7.8% discount rate (See Table G).

Results

The present value of the costs for energy and capacity were summed by month. The values were then levelized by month over the 5 year rate period, at a 7.8% discount rate. The monthly levelized values were averaged and rounded to get a single average annual cost (See Table G).

The total cost of Full Load Shaping is 0.32 mills per kWh. (See Table G)

PARTIAL LOAD SHAPING

To determine the charge for Partial Load Shaping, BPA estimated total Full Load Shaping revenues assuming all 1981 and 1996 power sales contract PF customers purchased Full Load Shaping for their entire load (Tacoma and Industrial Exemption loads were excluded) and dividing those revenues by the average monthly deviation in aMW times the average hours in a month (730). This results in a rounded per MWh per hr. cost of $2.27. (See Table G, line 50, column H).

INDUSTRIAL EXEMPTION

The Industrial Exemption allows any customer purchasing Full Load Shaping to exempt an industrial load from Full Load Shaping. It is generally used for loads of 5 aMW or larger. For 1981 Contract purchasers, the exemption results in a reduction in the amount of BPA deliveries to which Full Load Shaping charges apply. For 1996 Contract purchasers, the exempted industry' s load is excluded from total retail load to which the Full Load Shaping charge applies. Industrial Exemption is available to customers who have industrial loads that are predictable enough that a forecast made two months prior to the start of the billing month can accurately describe the monthly HLH energy and LLH energy for the load. With an Industrial Exemption, the customer pays an Industrial Exemption load shaping charge for the difference between forecast and actual Industrial Exemption loads.

The customer will provide BPA with a monthly forecast of heavy load hour (HLH) energy and light load hour (LLH) energy for each exempt industrial load. When actual energy use is less than forecast the customer will pay for that load shaping for the Industrial Exemption load at the rate of 1.16 mills/kWh on the difference between forecast and actual energy use. For actual hourly energy use above forecast, the customer will pay for load shaping for the Industrial Exemption load at the rate of 1.16 mills/kWh on the difference between forecast and actual energy use. If the customer varies from the forecast by more +1/-5% for more than one month out of any six-month period, the load may lose the exemption. Details of the rights of deviations for exempt industrial loads and of the test are stated in the GRSP sections relating to Industrial Exemption.

The study was done using PF rates, the average non-firm sales rate from the Full Load Shaping analysis and the average cost of purchased power plus purchased capacity from the Full Load Shaping analysis (see Table H). The study assumed a subscription of 700 MWs of plant capacity for the Industrial Exemption product, based on a forecast of load that would qualify for the exemption, a maximum curtailment of 5% (the limit of coverage under this product) and a probability of the outage occurring of 10% in any month. That probability was chosen to allow a reasonable amount of curtailment for a stable industrial load. The study calculates the number of MWhs of outage that could occur in each month, as the product of the 5% negative deviation bandwidth times expected Industrial Exemption of 700 MWs times the hours in each month.(see Table J fn 1). The study assumed that the MWhs of reduction from forecast were sold as nonfirm energy to the Pacific Southwest. The value of those sales is estimated from the Full Load Shaping Analysis (see Table H). The difference between the PF and nonfirm sales price was then multiplied by the outage in MWh times the assumed probability of the outage occurring in this month (10%) (The probability of outage, and of overruns, has been revised to correct an error in the supplemental Industrial Exemption Analysis). This procedure was duplicated for each month of each year in the rate period. The monthly values were summed and the resulting annual values were then converted to present value and levelized using a 7.8% discount rate to get five-year costs.

The study calculates the number of MWhs of energy overruns that could occur in each month, as the product of the 1% positive deviation bandwidth times expected Industrial Exemption of 700 MWs times the hours in each month.(see Table J fn 10). The study assumed that BPA purchased the MWhs of energy overrun on the surplus firm market at the average of the purchase prices from the Full Load Shaping Analysis (see Table H fn 2). The difference between the PF rate and surplus-firm purchase price was then multiplied by the outage in MWhs times the assumed probability of the overrun occurring in that month (10%). This procedure was duplicated for each month of each year in the rate period. The monthly values were summed and the resulting annual values were then converted to present value and levelized using a 7.8% discount rate to get five year costs.

The levelized costs of positive and negative deviations were summed and rounded to 1.16 mills/kWh.

DSI LOAD SHAPING

Determining the Amount of Variation Around Monthly Nomination

BPA determined the likelihood of up to a 15% increase or decrease in actual firm energy deliveries from the medium forecast of non-aluminum DSI load. BPA assumed a 25% chance of both a 15% overrun and a 15% underrun. Multiplying the MW quantity of fluctuation by the probability of the fluctuation results in an estimate of the expected MW fluctuation.

Product Cost

Energy

BPA first developed a set of 5-yr. IP rates using the average delivered IP rate of 22.6 mills/kWh and applying the marginal costs from the MCA to arrive at monthly HLH and LLH IP rates.

For energy deliveries in excess of a month' s nomination, BPA will either make additional purchases to meet these deliveries or forego an alternate sales opportunity. Such purchases or foregone sales are assumed to be at the nominal market firm power price for each month in each year from the Full Load Shaping product study.

For energy deliveries below a month' s nominations, BPA will sell into the nonfirm market at the monthly nonfirm energy prices. Such sales are assumed to be made at the nominal nonfirm market price for each month of each year from the Full Load Shaping product study. BPA sells into the non-firm market because BPA cannot know whether the customer will take delivery of the nominated amounts until the workday before delivery. The energy sold into the nonfirm market will have a price lower than the delivery price, while the cost of energy purchased to meet additional deliveries may be either above or below BPA' s firm energy rate.

Demand

The deviation in peak demand was assumed to be proportional to the energy deviation. The cost of additional demand is captured by including capacity costs in the on-peak power purchase prices used to cost deviations in excess of a months nominations. See the table labeled Development of Estimated IP Firm Energy Prices and Spot Firm Market Prices footnote 4.

Determining the Total Cost of DSI Load Shaping

The additional expected energy deliveries were multiplied by the difference between the firm purchase price and the assumed IP rate for that month, and the deliveries below medium forecast were multiplied by the difference between the nonfirm price and the assumed IP rate. Then, for each month, these amounts are summed to obtain the estimated cost of providing this service for that month. This estimated cost was then divided by the Calculated Energy Capacity for that month. Next, the present value of each month' s cost was determined for the 5-year rate period, using a 7.8% discount rate. Next, monthly levelized costs were determined for each month in the 5-year rate period. A monthly levelized cost was determined for each month using the monthly costs for each year and a discount rate of 7.8 percent. Finally, one cost of $201/CEC/month was determined by taking the simple average of the 12 levelized costs.

Determining Product Price and Billing Factor

The price of $201 per aMW per month of Calculated Energy Capacity was calculated as described above. The "Calculated Energy Capacity" is BPA's estimate of average monthly firm energy use for DSI plants operating at full capacity based on historical data. Details of the the determination of Calculated Energy Capacity may be found in the GRSPs relating to Calculated Energy Capacity.

Utility Factor

BPA multiplies the charge for Full Load Shaping and Load Regulation by the Utility Factor for customers purchasing those products under the 1981 Power Sales Contract. The Utility Factor is designed to ensure an equitable allocation among customers of the cost of those services. The factor modifies the Full Load Shaping and Load Regulation rates to create a more direct relationship between the costs incurred by BPA for providing these services to specific customers and the actual charge assessed.

The cost of providing the Full Load Shaping and Load Regulation services is related to the size of the customer's retail load, not to the amount of power the customer purchases from BPA. Without the Utility Factor adjustment, those customers that purchase only a portion of their power from BPA would pay proportionately less for the Load Shaping and Load Regulation services than those customers that purchase all of their power from BPA. The application of the Utility Factor adjusts the customer's Full Load Shaping and Load Regulation rate such that the cost paid by each customer for these services is relative to the size of their retail load. Because some customers may have extremely large Utility Factors, BPA will cap Utility Factors at six. BPA's estimate of customer Utility Factors is included in this documentation.

BPA will use the following methodology to calculate the Utility Factor for each Fiscal Year, with information from the following sources, if provided by the utility, or using BPA's estimate of the necessary information:

1. BPA power bills
2. Customer Financial and Operating Report (end of year)
3. Generation Report(s) (where applicable)

BPA will calculate a purchaser's Total Retail Load for the previous Calendar Year by aggregating all energy (kWh) purchased and/or generated to meet load during the Calendar Year. This calculation will be made from the information described above submitted by the purchaser to its BPA Account Executive or District Sales Office for the previous Calendar Year. If the purchaser fails to submit a Financial and Operating Report, and Generation Report as applicable, by June 1 following the Calendar Year, BPA will prepare an estimate of the purchaser's Total Retail Load for the previous Calendar Year, after consultation with the purchaser. For the purpose of determining the Utility Factor for the Full Load Shaping charge only, Total Retail Load is adjusted to exclude New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract.

Utility Factor for the applicable Fiscal Year for Metered Requirements customers = Total Retail Load for the previous Calendar Year, adjusted for the Full Load Shaping charge only to exclude New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract ÷ Energy Purchases under the 1981 Contract for the previous Calendar Year. For Actual Computed Requirements customers, the divisor is Computed Energy Maximum for the previous Calendar Year. If the Utility Factor as calculated by the foregoing formula exceeds six, the Utility Factor will be capped at six.

For customers who choose an Industrial Exemption, an Adjusted Utility Factor is calculated for the Full Load Shaping charge on a monthly basis. The calculation for the Adjusted Utility Factor for Metered Requirements customers is as follows: (1/12 times the customer's Total Retail Load for the applicable calendar year, excluding New Large Single Loads served with dedicated resources, *minus* the Industrial Exemption forecast for the current month) divided by (1/12 times the customer's BPA purchases for the applicable calendar year, excluding New Large Single Loads served with dedicated resources, *minus* the Industrial Exemption forecast for the current month). The calculation of the Adjusted Utility Factor for Actual Computed Requirements customers is: (1/12 times the customer's Total Retail Load for the applicable calendar year, excluding New Large Single Loads served with dedicated resources, *minus* the Industrial Exemption forecast for the current month) divided by (1/12 times the customer's Computed Energy Maximum for the applicable calendar year, excluding New Large Single Loads served with dedicated resources, *minus* the Industrial Exemption forecast for the current month).

The Full Load Shaping and Load Regulation charges are multiplied by the Utility Factor to determine the rates for Full Load Shaping and Load Regulation. For customers with Industrial Exemption load, the Full Load Shaping charge is multiplied by the Adjusted Utility Factor to determine the Full Load Shaping rate. In determining the Utility Factor and Adjusted Utility Factor for Full Load Shaping, New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract are excluded from Total Retail Load. The divisor for both the Utility Factor and Adjusted Utility Factor for Metered Requirements customers is BPA purchases, and for Actual Computed Requirements customers is Computed Energy Maximum.

Bonneville has updated the following table of Calendar Year 1994 Utility Factors from the supplemental proposal only to re-calculate Utility Factors for Actual Computed Requirements customers using Computed Energy Maximum for the divisor instead of BPA purchases. BPA will be preparing updated Utility Factors with customers in the manner described above.