RISK ANALYSIS

As a result of the settlement of the 1991 rate case, BPA committed to produce a 10-Year Financial Plan. As a part of the 10-Year Plan process, BPA and its customers worked together to devise a way to quantify BPA's ordinary operating financial risks. The results of that effort were the Short-Term Risk Evaluation and Analysis Model (STREAM), pre-STREAM risk models, and the Tool Kit Model. The following is documentation of BPA's implementation of the STREAM and the pre-STREAM risk models in the 1996 rate proposal.

The objective of the Risk Analysis is to evaluate the impact that various economic and generation resource capability variations could have on BPA's ability to make its annual U.S. Treasury payments during the rate test period. The Risk Analysis measures the financial risks BPA faces in terms of deviations in net revenues (revenues minus costs) from the revenue and expense forecast used to set rates. The results of the Risk Analysis are used to support the amount of “Planned Net Revenues for Risk" that are included in the revenue requirement.

The documentation is organized in two sections. In the first section, there is a discussion of the various risk models developed to provide input data into the STREAM. In the second section, there is a discussion of the logic incorporated into the STREAM.

Pre-STREAM Risk Models

Four separate risk models were developed to provide input data into the STREAM. These four pre-STREAM risk models assess the risk BPA faces due to Nuclear

Plant Performance, Economic and Weather Effects on Loads, California Nonfirm Energy Markets, and Fossil Fuel Prices. In addition to these four pre-STREAM risk models, Hydro Production risk is accounted for in the STREAM. The discussion below explains the data preparation required to incorporate Hydro Production risk into the STREAM. Following this discussion of data preparation for Hydro Production risk are discussions of the four pre-STREAM risk models.

Pacific Northwest Hydro Production Risk

The purpose of incorporating variability in Pacific Northwest hydro production is to quantify the risks associated with changes in hydro conditions relative to the hydro conditions used when developing rates. STREAM is a one-dam hydroregulation model which requires unregulated streamflow data, operational rule curves, water-to-energy conversion factors, ratios of Federal to Non-Federal generation, and Federal and Non-Federal hydro independent generation for each of the 50 Water Years. Also, since STREAM is a one-dam hydro regulation model, it can not accurately estimate spillage from the various dams on the Columbia and Snake Rivers under various streamflow conditions, rule curves, and operational constraints. Accordingly, the unregulated streamflow, operational rule curve, water-to-energy conversion factor, ratios of Federal to Non-Federal generation, Federal and Non-Federal hydro independent generation, and spillage data for the 50-water years for 1998 were obtained/derived from the Hydroregulation Study. This hydro data were then incorporated into the risk data files utilized by STREAM.

Risk Factor Estimation for Hydro Production

Unregulated monthly streamflow data for each of the 50 Water Years were converted from thousand cubic feet per second (kcfs) to average megawatts (aMW) using the water-to-energy conversion factors developed from results of the Hydroregulation Study. For each of the 50 Water Years, consistent sets of streamflows and hydro operations data from the Hydroregulation Study were used to estimate hydro production risk for BPA and the rest of the PNW region. Given this information, STREAM cycled through the 50 Water Years data (1929-1978) numerous times to obtain the desired number of net revenues. Before starting each 50 water year cycle, STREAM reset the reservoir level at the end of 1978 to the level that reservoirs began in 1929.

Results of the Hydro Analysis

The hydro risk and operations adjustment factors used in the "Surprise" cases in STREAM are represented as proportions of the monthly "average" values used for hydro production and operations in STREAM. The "Normal" case values for hydro production and operations used in STREAM are based on 1949 water conditions and hydro operations. Hydro production and operations under 1949 water conditions were used for the "Normal" case because net revenues were similar to the average of the net revenues for the 50 Water Years that was used when developing rates.

Nuclear Plant Performance Uncertainty

The purpose of the Nuclear Plant Performance Uncertainty Model (NPPUM) is to quantify the risks associated with the operational performance of the WNP-2 nuclear plant relative to the "Normal" values used in developing rates. The

NPPUM captures the risks of varying plant performance due to causes that are shorter than one month in duration and longer forced outages of varying duration. Results are based on sampling values from probability distributions whose parameters were estimated from historical data available in the Real-time Operations Dispatch System (RODS) data base. These data are actual generation values from 1985-1994.

<u>@RISK Computer Software</u>

The uncertainty models developed to perform the risk factor analyses were developed in the @RISK computer software package. This software is an add-in computer package to Microsoft Excel and is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that best reflects the risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK but are developed in analyses external to @RISK.

<u>Risk Parameter Estimation for Nuclear Plant Performance</u>

In preparation for developing the NPPUM, historical data for the WNP-2 nuclear plant was arranged sequentially (January through December) and then sorted according to month (all Januarys, all Februarys, etc.). Monthly sorted data were then sorted from highest to lowest and the median identified. Monthly generation values equal to zero were excluded from this determination, since they are related to either planned maintenance or forced outages. Standard deviations were calculated for values below and above the median with upper and lower bounds being identified. This allowed the quantification of risks above and below the median values to be constrained by appropriate upper and lower bounds; i.e., values below zero and values above rated capacity. Sequentially arranged data were used to assess the frequency and duration of forced outages in one or more months.

<u>Risk Model for Nuclear Plant Performance</u>

The information derived in the risk parameter estimation analysis, were input into probability distributions in the NPPUM. Information provided for each month consisted of the median output, the standard deviation above and below the median values, appropriate high and low ranges, the likelihood of a forced outage, and a statistical parameter which reflects the duration of forced outages. The probability of a forced outage in a given month for the WNP-2 was captured through the use of the <u>DISCRETE</u> probability distribution in @RISK and the probability of forced outages of various durations through the <u>POISSON</u> probability distribution. The value used for the probability of forced outage in a given month was three percent. The parameter required for the <u>POISSON</u> distribution is the mean of the length of the outages; this value was two months.

The likelihood of nuclear plant performance above and below the median values is based on sampling values from a standard normal distribution (mean = 0 and standard deviation = 1). This sampling method yields 50 percent of the observations above and 50 percent below the median values. The variability above and below the median values is quantified by sampling values from a standard normal distribution, multiplying the sampled values by the appropriate high or low standard deviations, and adding these values to the median values. Values that are below or above appropriate levels are revised either upward or downward to conform to appropriate lower and upper constraints. The model then checks to see if a forced outage condition was sampled from the DISCRETE distribution. If a forced outage conditions is sampled, then the NPPUM samples from the POISSON distribution to determine the length of the forced outage. In these cases, monthly nuclear performance values are set to zero for the number of months of the forced outage and are allowed to continue between years, when applicable. When the duration of the forced outages extends into the maintenance period, the maintenance period is included in the number of months of the outage.

Results of the Nuclear Plant Performance Analysis

The nuclear risk adjustment factors used in the “Surprise" cases in STREAM appropriately represent proportions of the “Normal" values used for nuclear plant performance assumed when developing rates.

Public Utility Load Uncertainty

The public utility load uncertainty model is a monthly simulation mini-model. It is based on the two models used to generate the base case load forecasts (base case load models) for the non-and small generating public utility (NSGPU) and generating public utility (GPU) customer groups. There are three uncertain variables in the model--employment, heating degree-days and cooling degree-days. The uncertainties are specified as a difference from the base case load forecast and, consequently depend only on employment and degree-days.

The model structure is the same as the structure used in the 1993 rate case. Minor modifications were made to the worksheet model to make it easier to update and operate.

Risk Parameter Estimation for Public Utility Loads

Uncertainty in the utility load forecast due to employment has two components -- level and cycle. The uncertainty in the cycle is captured by examination of the sample standard deviation of the historical month-to-month exponential growth rates. Growth rates are assumed to be normally distributed. The uncertainty in the level is modeled via a simple classical linear time series model. Employment is regressed on monthly dummy variables, and a linear, squared, and cubed time component. The standard error of the resulting regression is used to capture average monthly uncertainty. This is assumed to be normally distributed. The cycle imparted to the forecast is a combination of cycle uncertainty and that which is inherent in the base case forecast. The random draws on employment between the two classes of customers are assumed to be perfectly correlated, and thus, each value drawn is used for both classes of customers. The employment specification is shown below:

(1) $$EMP_0^R = EMP_0 + u,$$

EMP_0^R is the random (superscript R) component in the initial time period (period 0) that captures uncertainty in the employment level,

u = random shock applied to the level of employment in the initial period. It is normally distributed with mean = 0, and standard error = 40.1.

$$(2) \qquad EMP_t = EMP_{t-1} * e^{r_t + \varepsilon_t}$$

EMP_t is the component that captures uncertainty in the month-to-month growth rate in employment,

r_t = exponential growth rate of employment between the previous and current time periods (t - 1 and t), from the base case forecast

ε_t = random shock on the period-to-period growth rate in employment. It is normally-distributed with mean zero and standard deviation = 0.011604.

The following equation combines the coefficient(s) from the base case models and the uncertain components of employment.

$$MW_t^{EMP} = f\,(EMP_t)$$

MW_t^{EMP} = electric energy attributable to employment

Heating and cooling degree-days are the weather component of uncertainty in the utility load forecast. These are assumed to be normally distributed and perfectly inversely correlated. Following draws from the normal distribution, the lower limit of heating and cooling degree-days is limited to be zero, to recognize the fact that negative degree-days is not a meaningful number. The weather component is written as:

$$CDD_t = CDD_t^N + \eta_t^{CDD}$$
$$HDD_t = HDD_t^N + \eta_t^{HDD}$$

The superscript "N" denotes normal degree-days.

CDD_t is the random cooling degree-days in period t.

HDD_t is the random heating degree-days in period t.

η_t^{CDD} = random shock on monthly cooling degree-days.

η_t^{HDD} = random shock on monthly heating degree-days.

Electric energy demand attributable to weather depends on degree-days and the coefficient(s) from the base case models.

$$MW_t^{DD} = f\,(HDD_t, CDD_t)$$

Risk Model for Public Utility Loads

The individual pieces, described above, are added to the baseline forecast to create a random public utility load model. The specification can be shown as the sum of three components - the employment component, the weather component and the non-random component. The non-random component captures the effect of electricity prices and "shoulder months".

Results of the Public Utility Load Analysis

The output of the model is used as input by the STREAM. Each public load model produces two outputs:

(1) Each month's average loads + deviations due to weather from each month's average.

(2) Each month's average loads + deviations due to economic variations from each month's average.

Each of the components is expressed as a proportion of each month's average loads.

California Market Uncertainty

The California Market Uncertainty Model (CMUM) quantifies the risks associated with the California market for spot market energy relative to the base values estimated by the Accelerated California Market Estimator (ACME) for developing rates. The CMUM provides estimates of the California spot energy market under varying load and resource conditions in the PSW. Risk factors included in the model are hydro production and load variability due to changes in weather conditions. To the extent possible, the logic in CMUM is consistent with the ACME. With the exception of the values used for the risk factors, data used in the model are consistent with data used in the ACME. California hydro production data used for quantifying hydro risk were derived from data reported by the Energy Information Administration for 1977-1985. Mean monthly hydro production values representing average values over a longer time period than 1977-1985 were derived from data used in Elfin during the CEC ER-92 Study. Variability in monthly California loads was derived from data used in various studies submitted to the California Public Utility Commission from 1985-1990.

ACME is an economic dispatch model which produces one estimate of spot market conditions, dispatches various California resources on an hourly basis, and estimates spot market conditions in three-hour increments. Like ACME, CMUM treats all California electric utilities as a single utility. Unlike ACME, CMUM produces a large number of probability-weighted market conditions, dispatches only non-displaceable resources, and provides load estimates for three load periods during the day (peak, shoulder, and off-peak). The dispatching of displaceable resources for the peak, shoulder, and off-peak periods are not performed by CMUM; but rather is reflected by the size of the market in STREAM. An analysis of the displaceable resources likely to be available for displacement during the three load periods was performed separately from CMUM and was based on an understanding of hourly resource dispatch in ACME. This information is an input to STREAM so that the market is known when STREAM begins to market nonfirm energy.

Risk Parameter Estimation for the California Market

In preparation for quantifying California hydro production risk, the historical data were sorted by month (all Januarys, all Februarys, etc.) and the standard deviations were calculated. The highest and lowest values were identified to set upper and lower bounds on the hydro results. This allowed quantification of risks to be constrained by appropriate upper and lower bounds, i.e., values below zero and values above rated capacity.

Historical California load data were arranged sequentially (January to December) and the effect of load growth due to economic growth was removed by de-trending loads. The de-trending adjusts the load data to reflect load variability solely due to weather variations. To de-trend loads, a simple linear regression equation was developed, with loads as the dependent variable, and time as the independent variable. This specification yielded an upward sloping regression line. The sequentially arranged data were then adjusted by the results of the regression analysis to remove the effects of continuously increasing loads in California. The de-trended historical load data were sorted by month (all Januarys, all Februarys, etc.) and the means and standard deviations for each month were calculated.

Risk Model for the California Market

The information derived in the risk parameter estimation analysis were input into probability distributions in the CMUM. Information provided for hydro production for each month consisted of the mean, the standard deviation, and appropriate upper and lower limits. Hydro variability was captured through the use of a truncated normal distribution (values are sampled from a normal distribution but are truncated by upper and lower limits) in @RISK. Monthly load variability was captured by specifying the mean and standard deviation in a normal distribution.

Given this information, CMUM samples values from the probability distribution for hydro production and load variability. Based on load and resource information, CMUM shapes available hydro to serve loads during various periods of the day depending on storage constraints and maximum generation capability. Hydro is dispatched such that it first shapes as much hydro production as constraints will allow into the peak period, then repeats the process for the shoulder and the off-peak periods, with any residual being spilled. While firm sales contracts are not a risk factor in the model, energy from these contracts was also shaped between the periods based on constraints imposed by terms of the contracts. If after subtracting these resources from loads, it is found that residual loads are higher in the shoulder period than the peak period, hydro production is reshaped so that residual loads are equal for the two periods.

CMUM allocates loads between months and periods of the day through coefficients developed from load curves. Using these coefficients, annual load values are initially allocated between months and further subdivided into three-hour increments during a week. Load variability in CMUM is calculated on a monthly basis and is reflected in changes in the loads experienced in the three-hour increments during a week. Loads in these three-hour increments are further grouped to reflect average loads during peak, shoulder, and off-peak periods. Loads in the three periods are then reduced by subtracting shaped variable hydro production, shaped contracts, and fixed output from non-displaceable resources.

Results of the California Market Analysis

Risk results from CMUM are reflected as proportions of the monthly "Normal" load values that CMUM calculates for the peak, shoulder, and off-peak periods. The "Normal" values used for the risk factors are the expected values of the probability distributions. The monthly base values for all three periods are specified in STREAM and reflect expected spot market conditions. The risk adjustment factors used in the "Surprise" cases in STREAM are proportions of the "Normal" spot market values.

Fuel Price Uncertainty in the California Market

The fuel price uncertainty model is a monthly simulation mini-model. It is based on (1) a time series regression model (ARIMA(2,0,0)*(1,0,0)) that was developed using actual spot prices of natural gas delivered to California utilities, in 1992 dollars; and (2) the long-term monthly price forecast. The (2,0,0) term represents the nonseasonal lag structure of the fuel price specification. The 2 indicates the number of lagged values of the price variable that will be included in the specification (autoregressive component). Here, we have $y_t, y_{t-1}, \text{and } y_{t-2}$. The first 0 indicates the number of times the price variable needs to be differenced to satisfy the model assumptions. The final 0 indicates the number of lags of the disturbance term to include in the specification (moving average component). The (1,0,0) term has an analogous interpretation, but applies to the seasonal components of the variable. The fact that there is a nonzero value in the (1,0,0) term indicates that the series has a seasonal component. The historical data covered the period June, 1986 through February, 1993. Uncertainty in spot prices is due to two components-- (1) short-run cyclical uncertainty as captured by the error between the actual historical values and the equation's estimates, and (2) long-term trend uncertainty as captured by variation in the long-term equilibrium price. These uncertainties were incorporated in a formal Monte Carlo simulation model using @RISK.

Risk Parameter Estimation for Fuel Prices

The time series regression equation is written as:

$$(1-\phi_1 L-\phi_2 L^2)*(1-\Phi_1 L^{12})*\ln(y_t)=\alpha+\varepsilon_t$$

$$(1-1.0951*L-(-0.4733)*L^2)*(1-0.2674*L^{12})*\ln(y_t)=0.8805+\varepsilon_t$$

$$\hat{\sigma}_e=.07546$$

where L^k = backshift or lag operator. The superscript k means that you lag the variable y by k months.

The model was estimated using the Forecast Pro For Windows software package, developed by Business Forecast Systems.

Risk Model for Fuel Prices

The simulation model is a weighted average of the time series equation and the simulated long-term price forecast of natural gas. It is written as:

$$y_t=\exp[0.5*(\mathrm{ARIMA}(2,0,0)*(1,0,0))+0.5*\ln(y_t^{LT})]$$

where

y_t^{LT} = simulated long-term forecast of natural gas prices in month t.

The short-term random component, e_t, is normally-distributed with mean zero and standard error = 0.07546.

The simulated long-term price forecast is equal to the base case monthly price forecast adjusted by the percent change between the simulated and the base case long-term equilibrium price. The relationship is written as:

$$y_t^{LT} = y_t^{lt\,fcst} * \left(\frac{Tnormal(y^{LT\,Equil}, (max - min)/4, min, max)}{y^{LT\,Equil}} \right) / k$$

where

$y_t^{lt\,fcst}$ = long-term monthly price forecast in month t

$y^{LT\,Equil}$ = long-term equilibrium price forecast

min = lower limit for the natural gas price

max = upper limit for the natural gas price

k = normalizing constant to adjust the percent change to one in equilibrium.

<u>Results of the Fuel Price Analysis</u>

The output of the model is used as input by the STREAM. Output of the model consists of each month's simulated price. This output is expressed as a proportion of the entire simulation's average price.

Short Term Risk Evaluation and Analysis Model (STREAM)

The STREAM is a hydro regulation model that runs on a microcomputer (PC). It makes monthly operational and economical decisions based on various reservoir, streamflow, load, nuclear performance, and nonfirm spot market conditions. As each of these conditions vary simultaneously, STREAM estimates BPA's net revenue (revenues minus costs) for each month and sums them for the fiscal year.

Forecasts of net revenues are made for a base case (“Normal" case) and numerous risk cases ("Surprise" cases). The “Normal" case for each fiscal year reflects the values used on a planning basis. Information used in estimating net revenue for the “Normal" case correspond to the data used to forecast revenues and purchase power costs when setting rates in the Rate Analysis Model. The “Surprise" cases are derived by multiplying the “Normal" values for the risk factors by the adjustment coefficients developed in the risk models. Results from these cases reflect the uncertainty associated with the risk factors that affect BPA and the impact that changes in these factors have on BPA's net revenues.

The differences in net revenues between the “Normal" case and “Surprise" cases reflect the net revenue risk BPA faces relative to the base estimate inherent in the ratesetting process. By subtracting the net revenue result for the “Normal" case from the results of each of the “Surprise" cases, a series of deviations in net revenues is developed. The result is that the frequency of various net revenue outcomes is directly proportional to the likelihood of their occurrence.

General Description

STREAM is a "stock-flow model", with the stock being the water stored behind reservoirs and the flow being the monthly inflows into the reservoirs and outflows from the reservoirs. STREAM attempts to replicate the PNW Coordinated Hydroelectric System operations reflected in HydroSim - the hydroregulation model used to perform the Hydroregulation Study for the 1996 rate case. STREAM operates the regional hydro system as one unit and allocates hydro production between BPA and other PNW utilities (STREAM models other PNW utilities as a single utility called "NW") based on coefficients derived from results of the Hydroregulation Study. Hydro operations are based on "rule curves" specified in terms of ksfd at the end of each month. Marketing and purchase power decisions are made based on comparing monthly projected reservoir levels in ksfd at the end of the month with rule curves specified in ksfd at the end of the month. Supply and demand curves are used to allocate water in the reservoirs among alternative uses; they are designed to reflect the priority of uses of the water.

Hydro Operations - Rule Curves

The chief criteria for actual operation of the hydro system are "rule curves". At the beginning of the operating year (August 1) operators and planners of the hydro system develop these "rule curves" which govern reservoir operations for the next year. These "rule curves" define the rules for reservoir operations depending on the level of the reservoirs as of August 1. They reflect how the reservoir shall be drafted through the year depending on actual streamflows and define how reservoirs can be drafted for varying priorities of use.

Except for the first year of the analysis, the rule curves that STREAM uses to govern hydro operations for the 50 Water Years are the reservoir levels at the end of each month (in ksfd) reported in the output of HydroSim. These monthly reservoir levels were derived by starting the reservoir levels of the PNW Coordinated Hydroelectric System close to full at the beginning of Operating Year 1929 and continuously operating the hydro system under streamflow conditions experienced from the beginning of Operating Year 1929 through the end of Operating Year 1978 (this is referred to as a "continuous" hydroregulation study). The various monthly inflows, various monthly hydro operation constraints, and the differences in reservoir levels for each dam exercise a composite impact that is reflected in the total hydro system reservoir levels, which in turn ultimately impacts hydro production and reservoir operations.

In the first year of the analysis, STREAM uses a combination of rule curves to govern hydro operations. This is necessary because the reservoir levels at the end of each month (in ksfd) reported in the output of HydroSim were derived from a continuous hydroregulation study. Starting reservoir levels in the current year will differ from the starting reservoir levels for each of the 50 Water Years. Accordingly, in the first year, STREAM uses the reservoir levels at the end of each month from HydroSim as the lower limit for reservoir operations and upper rule (flood control) curves (URCs) from HydroSim as the upper limit for reservoir operations. Finally, from August to March in the first year, the higher of either the reservoir levels at the end of each month reported in HydroSim output or the Energy Content Curve (ECC) and Variable Energy Content Curves (VECCs) used by HydroSim, govern storage versus secondary energy sales decisions for each of the 50 Water Years; from April through July, storage versus secondary energy sales decisions are based on the reservoir levels at the end of each month reported in HydroSim output.

Purchasing Decisions

Regardless of the year of the analysis, power purchase decisions are based on projected reservoir levels at the end of the month (in ksfd) relative to the reservoir levels at the end of each month (in ksfd) reported in HydroSim output. Projected monthly reservoir levels are calculated by taking the beginning monthly reservoir levels and adjusting them by the operational spill, inflows, nuclear plant output, hydro independent output, and loads. If projected reservoir levels are lower than the reservoir levels at the end of each month (in ksfd) reported in HydroSim output, first Williston Storage, then Non-Treaty Storage, and then finally power purchases are used to attain the reservoir levels at the end of each month (in ksfd) reported in HydroSim output. If projected reservoir levels are higher than the reservoir levels at the end of each month (in ksfd) reported in HydroSim output, then no power purchases are made and STREAM attempts to allocate any secondary energy to alternative uses.

Marketing Decisions

Except for the first year of the analysis, if projected reservoir levels at the end of the month (in ksfd) are above the reservoir levels at the end of each month (in ksfd) reported in HydroSim output, then STREAM attempts to allocate any secondary energy to alternative uses. Storing in Williston Reservoir (in British Columbia) in May and June and storing in Non-Treaty Storage as much energy as allowable are the highest priority uses of secondary energy. In the first year of the analysis, during August through March, the higher of either the reservoir levels at the end of the month reported in HydroSim output or the Energy Content and Variable Energy Content Curves, govern secondary energy sales; during April through July, reservoir levels at the end of each month (in ksfd) reported in HydroSim output govern secondary energy sales. The Variable Energy Content Curves (VECCs) for each of the 50 Water Years were developed from HydroSim input data by summing all the Variable Energy Content Curves for all the dams comprising the PNW Coordinated Hydroelectric System. These VECCs govern hydro operations during the months of January through July. The Energy Content Curve (ECC) was extracted from HydroSim input data. It helps govern hydro operations during the months of August through December and has the same values for all 50 Water Years. In actual hydro operations, the ECC and VECCs govern secondary energy sales for each of the various dams - provided that dam constraints don't override these rule curves.

Calculations for purchase power and nonfirm prices in STREAM were made in a manner consistent with the NFRAP. Purchase power prices, which are estimated as a function of the quantity of power purchased, are calculated from regression equations developed from output data from PMDAM.

Off-System Storage

In addition to storing secondary energy in Treaty Storage, STREAM, like the NFRAP, can opt to store additional energy in Williston Reservoir in British Columbia in May and June and in Non-Treaty Storage in several months of the year. Williston Storage involves storing 400 Mw-Mo of energy in the month of May and another 400 Mw-Mo of energy in the month of June (during the fish flow period) and removing 400 Mw-Mo of energy in August and another 400 Mw-Mo of energy in September. Non-Treaty Storage reflects the additional storage available to BPA under the Non-Treaty Storage Agreement with storage being governed by a maximum storage limit and by monthly constraints on the maximum amount that can be stored and removed. Storing in Williston Reservoir and in Non-Treaty Storage to the maximum amount allowed has the highest priority in the use of any secondary energy.

Nonfirm Sales

Sales to California are divided into peak, shoulder, and offpeak periods. Prices for nonfirm spot sales in the peak and shoulder periods in California are derived by finding the lowest price nonfirm sold for during these times and making all sales at this rate. Prices for nonfirm spot sales in the offpeak period in California are derived by finding the lowest price nonfirm sold for during this period and making all sales at this rate. Prices for nonfirm sales to the NW are not time differentiated, but are determined in the same manner.

Allocation of Resources - Supply and Demand Curves

STREAM uses a series of demand curves and a derived supply curve to allocate the water in the reservoirs among varying priority uses and to make decisions on whether to store or release water for each of these uses. By assigning higher values to certain uses than others, the priority is set on how the water in the reservoirs will be used, both for BPA and the NW utility.

The first of these demand curves is the "Demand to Hold". It defines the various markets for holding water behind the dams throughout the remainder of the year and assigns relative values to each of these markets. Holding water in the reservoirs to meet firm loads for the remainder of the year has the highest priority; accordingly, it is assigned the highest value. Thus, the "Demand to Hold" is a planning mechanism which allocates and reserves the stock of water behind the dams for high value uses throughout the year, and then assigns each of the uses a value .

The supply of water available for hydro production depends upon the stock of water behind the reservoirs and the amount of the monthly inflows. For a given supply, a supply curve is derived by assigning the quantities and prices in the "Demand to Hold" curve to the amount of water available based on reservoir relationships to the rule curves. This supply curve reflects the fact that certain uses of water have higher values than others and thereby reserves the amount of water necessary to meet these high value uses.

To the extent that supply exceeds the "Demand to Hold" (which it typically does during the runoff period), excess hydro is available to serve other lower priority (and value) markets. Accordingly, five additional demand curves were developed for marketing excess hydro. These demand curves contain the various quantities of displaceable resources, by resource type, that BPA and the NW have and additionally the amount of displaceable resources in California during peak, shoulder, and off-peak hours. Marketing options for excess hydro consist of the following: (1) BPA to BPA, (2) NW to NW, (3) BPA to NW, (4) PNW (BPA and NW) to California peak market, (5) PNW (BPA and NW) to California shoulder market, (6) PNW (BPA and NW) to California off-peak market. BPA to BPA and NW to NW represent the use of hydro to serve firm load as well as to displace higher-cost resources in the BPA and NW resource stacks. The other marketing options represent markets for nonfirm energy sales. NW selling to BPA and BPA selling to NW for firm loads is not allowed by STREAM. The values assigned to each of the displaceable resources were calculated to yield values similar to those used in the NFRAP. For the PNW market, the values assigned to each of the displaceable resources were the smaller of either 85 percent of their decremental costs or their decremental costs minus 2 mills. The downward adjustments of these values from the decremental costs reflect the fact that market prices offered to owners of resources need to be lower than the decremental costs of their resources for displacement to occur. Similarly, for the PSW market, a total downward adjustment of 4.5 mills was made to the decremental costs to reflect approximately a 2.5 mill displacement incentive calculated internally in ACME and an additional 2 mill displacement incentive made by the NFRAP. Given the water available for use and the quantity and price of alternative uses, STREAM determines the highest value market or markets for that water and allocates the water between holding for future loads and releasing water for sale in the current month.

Nonfirm sales by BPA to the California markets are limited in STREAM by the transmission capacity available for nonfirm sales on the Southern Intertie. Monthly transmission capacities available for nonfirm sales on the Southern Intertie were calculated by subtracting loopflow, maintenance, and outage limitations and firm wheeling transactions from the transfer capability.

Data Sources

Monthly BPA Loads and Resources - Loads and Resources Study for the 1996 final rate proposal. The final proposal loads and resources may differ slightly from those used in STREAM because the STREAM analysis was performed before the RAM was finalized.

Monthly NW Loads and Resources - Loads and Resources Study for the 1996 final rate proposal. Derived by subtracting BPA loads and resources from PNW loads and resources.

Monthly Unregulated PNW Streamflows at The Dalles for the 50 Water Years - Input file used by the HydroSim Model for the 1996 final rate proposal.

Monthly BPA Percentage of PNW Streamflows for the 50 Water Years - Based on Regional and Federal energy values from output by the HydroSim Model for the 1996 final rate proposal.

Monthly Water-to-Energy Conversion Factors for Hydro Generation for the 50 Water Years - Based on outflow data at The Dalles and Coordinated System hydro generation values from output by the HydroSim Model for the 1996 final rate proposal.

Monthly Water-to-Energy Conversion Factors for Storage for the 50 Water Years - Based on reservoir level data in terms of ksfd and Mw-Mo from output by the HydroSim Model for the 1996 final rate proposal.

PNW Coordinated Hydroelectric System Spill for the 50 Water Years - Based on output data from HydroSim for the 1996 final rate proposal.

Federal and Non-Federal Hydro Independent Generation for the 50 Water Years - Based on output data from HydroSim for the 1996 final rate proposal.

Rule Curves and BPA Percentage of Regional Storage - Based on input and output data from HydroSim for the 1996 final rate proposal.

Monthly California Displaceable Resource Markets - California Market Uncertainty Model using data from the CEC's ER-94 through ACME.

Federal and Non-Federal Transmission Capabilities and Firm Transactions on Southern Intertie - Based on data used in the ratesetting process, from the NFRAP, ACME, and RAM.

Output

STREAM allows the user the option of using several different options as to the amount and type of output they would like to obtain. These options range from annual summary data to very detailed monthly information. The final product from STREAM is a vector of net revenues; all other information is used for diagnostic purposes. These net revenues are passed into the Tool Kit Model to analyze the Administrator's risk policy.