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# THE BPA POWER MARKET DECISION ANALYSIS MODEL: METHODOLOGY REPORT

Prepared for the

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*Any editorial or technical corrections on this draft would be appreciated.*

# The BPA Power Market Decision Analysis Model: Methodology Report

## ABSTRACT

This report describes a computer model of the Western United States bulk power market. The model is designed to support the analysis of decisions to sell or purchase power, or acquire generating resource for the Bonneville Power Administration (BPA). The model simulates both hourly operation and long-term (30 year) expansion of all major utilities in the Western U.S. bulk power market. All major generating and transmission systems and economy energy, firm capacity, firm power and option energy sales contracts among the utility parties are simulated. The model determines market transaction prices and mutually beneficial levels of power contracts among the parties, least-cost resource acquisitions, and operating levels for generating resources, transmission lines and contracts.

The modeling approach is based on an economic equilibrium of prices and quantities over time. Each party is assumed to act to serve its native load customers at least cost. An iterative solution algorithm is used to solve a large set of nonlinear, simultaneous equations that describe the physics and economics of generation, transmission and contract resources and the behavioral/economic decision rules and criteria used by each party. The model attempts to describe actual rather than purely optimal decision making, but it is also capable of finding least-cost operating and acquisition decisions. Environmental emissions, and emission constraints and taxes are treated in the model. Uncertainty in hydro inflows, fuel prices, power loads and resource availability is represented using the Monte Carlo method. Decisions in the model are not deterministic but vary by game based on conditional expectations across games.

# PREFACE

The purpose of this report is to provide documentation of the modeling methodology underlying the Bonneville Power Administration's (BPA) Power Market Decision Analysis Model (PMDAM). Other user documentation is in preparation and the computer code itself is documented with extensive comments. This document is intended to describe the model and its methodology to those who wish to gain a fundamental understanding of the model, without the burden of reading the computer code and more detailed documentation.

Development of this model began in 1986 to meet BPA's needs for information and strategies to support marketing of surplus firm energy and capacity. Subsequently, the model has been applied to a range of decision problems within Bonneville, but it has remained an internal model because of its use in support of contract negotiations. In 1990, BPA decided to make public the model methodology, data, and results and to ask for outside review so that the model may be used to support other BPA decisions that require public comment. The publication of this report is part of this review process and we invite the readers to give us their critical comments and suggestions.

Many BPA managers contributed to the development of this model. Initially, Sue Hickey, Bob Lamb, Paul Norman, Walt Pollock, and Ed Sienkiewicz established this project as a major new effort by BPA. Over the last three years, Syd Berwager, Larry Kitchen, Bob Lewis, Bruce McKay, Shirley Melton, and Dennis Metcalf have provided project management and oversight. Methodology development and programing has been led by the author as a consultant to BPA with the primary support of BPA professionals Gerry Bolden, Flor Francisco, Ron Hicks, Dennis Phillips, Dave Teuscher, Terry Thompson, and Cindy Van Dusen. Model input data have been assembled by the above persons and by Kathy Craig and Don Weaver. Many others at BPA have contributed by their suggestions and reviews of model results, methodology and data.

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# The BPA Power Market Decision Analysis Model: Methodology Report

## 1. Introduction

### 1.1. Purpose of the Model

The Bonneville Power Administration (BPA) is a federal power marketing agency primarily responsible for marketing the electric power generated by the federal hydro electric projects on the Columbia River. BPA owns and operates the major transmission lines within the Pacific Northwest and the interties to the California and British Columbia borders. BPA facilitates the development of new generating resources within the Pacific Northwest through contracts to purchase generation, but it does not directly own any generating resources. BPA markets only to other utilities and to a few very large directly-served customers such as aluminum smelters. Wholesale power marketing is the principle function of the agency.

*PMDAM supports the analysis of long-term power marketing and resource acquisition decisions...*
*By simulating the west coast power market.*

The BPA Power Market Decision Analysis Model (PMDAM) was originally developed for the analysis of marketing strategies and decisions concerning long-term power sales contracts. Power sales contracts are complex because they may specify when, where, how much, and at what price power is to be delivered over twenty years or more. Often the contracts provide for seasonal or daily exchange of power to take advantage of the diversity in loads and resources among west coast utilities. Analysis of these contract decisions requires a model with sufficient detail in those aspects of the power market that are relevant to contract decisions while suppressing irrelevant detail.

In addition to the model's use for long-term power marketing decisions, the model is also applicable to many long-term power purchase and resource acquisition decisions and to coordinated west coast system planning.

### 1.2. Everything is Connected

Analysis of contracts for the sale of power cannot be isolated from modeling of the operation and expansion of the power systems within the markets served by the utilities participating in the sale. Power sales change the operation of existing resources and may change the need to acquire new resources in the participant's systems.

For example, some contracts contribute to meeting the buyer's peak hour needs thereby displacing the operation of high-variable cost resources and contributing to system reliability. Alternatively, the buyer could acquire a high-fixed, low-variable cost generating resource such as a coal-fired plant or a low fixed, high variable cost resource such as a gas turbine plant. The price the buyer is willing to pay for the contract power depends on the costs of these and other alternatives. Likewise, the price the seller is willing to accept depends on the seller's other sales, purchase and resource alternatives.

In power marketing and resource planning, everything seems to be connected to everything else. The principal purpose of this model is to cut through this complexity and connectedness to develop insight into the key factors that determine BPA's best power marketing and resource strategy.

## 1.3. Features of the Model

PMDAM is a large and very powerful model with a number of unique features of great value to power market decision analysis.

PMDAM simulates both the physics of the power systems and the decision making by parties within the market. The physics of the power systems include such concepts as supply /demand balances and transmission losses. The decision making by parties include decisions to acquire resources or to buy and sell power.

In simulating decision making in the market, one could assume optimal decision making, but then the model may not simulate actual market conditions where decision making may be affected by factors not explicitly modeled in PMDAM. PMDAM attempts to simulate actual decision making in the market by assuming each party strives for, but does not necessarily attain, least-cost economic solutions. Behavioral parameters are used to describe the degree to which least-cost, optimal decision making is attained. Consequently, the modeling methodology is able to simulate a range of decision making behavior from arbitrary decision rules to least-cost economic optimal behavior.

In simulating economic decision making, environmental and other non-monetary considerations are modelled by PMDAM either as constraints or by assigning monetary values to non-monetary outcomes.

PMDAM assumes each utility party will act in its own interest and attempt to find the least-cost plan to serve its native load customers. Each utility need not have the same objective function, discount rate or environmental preferences.

The model coordinates decisions among the parties by finding contracts and exchanges that are beneficial to the parties involved (WIN-WIN) and result in an economic balance, or equilibrium of supply and demand, among the parties at an agreed price. Both market quantities and market prices are computed by the model.

The model determines the hourly operating balance of all native loads, generating resources, contract loads and contract resources. Limits and losses on transmission between the parties are accounted for. This hourly detail is augmented by daily, weekly, monthly and annual balances. The hourly detail is necessary because many aspects of long-term marketing and resource planning cannot be addressed without some level of hourly modeling.

***PMDAM FEATURES***

***Least cost, economic/environmental optimum solution for each party.***

***Economic equilibrium solution among parties.***

***Hourly operating balance of loads, resources, contract loads, contract resources and transmission.***

***Multi-year, least cost acquisition of resources and contracts for each party.***

***Extensive marginal cost and total cost outputs.***

***Uncertainty in key variables.***

Simultaneously with the modeling of operations, PMDAM determines the multi-year, planning balance for resources and contracts for each party. The planning objective is to meet firm capacity and firm energy reliability criteria while minimizing each party's total fixed and variable costs. Generating resource acquisition decisions are simulated for each party as are decisions to sell or purchase power on a long-term basis.

For every constraint in the model, the methodology associates an opportunity price that gives the change in a party's total cost for a unit change in the constraint. For example, the hourly energy opportunity price for a utility at a given location is associated with the constraint that supply equal demand at that location for the utility in that hour. The hourly energy opportunity price is the lowest price in mills/kWh the utility should accept for any economy energy sale in that hour at that location.

PMDAM employs many opportunity prices including those related to transmission, hydro operation, thermal unit commitment, maintenance, firm capacity, and firm energy. These opportunity prices are fundamental to the iterative algorithm used to solve the model. Opportunity prices also are useful analysis outputs since they summarize how much a party is willing to pay for each fundamental commodity in the market.

Opportunity prices are also called marginal costs. Usually, the two terms can be interchanged, but when discussing algorithms and models it is easier to refer to marginal cost as a price. The adjective *opportunity* distinguishes the price that is the marginal cost from other prices such as average cost prices and indicates that the price is the increase in cost (or decrease in benefits) associated with a change in a constraint. The change in the constraint either eliminates or provides an *opportunity* to reduce cost.

Opportunity prices are also called shadow prices. In the mathematical programming literature, the shadow price is the price associated with each constraint in a constrained optimization problem and is the change in the objective function per unit change in the constraint.

Opportunity prices in this report are given the Greek letter $\lambda$ , which in English is the letter l. The symbol $\lambda$ is used by tradition to honor the mathematician, Lagrange who developed some of the basic theory underlying the methodology of PMDAM.

Finally, PMDAM explicitly represents uncertainty in key variables which affect those outputs of the model important to decision making. Currently, load, fuel prices, hydro inflow conditions and generating plant availability are treated as uncertain variables. Uncertainty is modeled as resolving over time. Initial decisions simulated in the model are made in the face of uncertainty using probability weighted expected values. Subsequent decisions simulated in the model are conditioned on the resolution of the uncertainty over time. This means that the acquisition and operating decisions simulated by the model adjust as uncertainty is resolved.

## 1.4. Organization of the Report

The main body of this report is organized in four sections. Section 2 describes in mostly non-mathematical terms what the model does and how it works. Section 3. presents the basic mathematics underlying the model and motivates the model from the perspective of economic and optimization theory. Section 4. describes the computer implementation of the model. Section 5 illustrates the output and uses of PMDAM. The appendices list the variables and the important equations of the model.

# 2. Scope of the Model

## 2.1. Basic Structure of the Model

PMDAM simulates the west coast wholesale power markets. The basic structure of the model is shown in Figure 2.1.

At the center of the figure is the system of equations that describe the model in mathematical terms. At the right are the decision criteria used by utilities and their regulators. At the left are the basic physical system elements. At the top are the key dimensions that describe the coverage and level of detail in the model.

All of the inputs into the center box determine the equations that form the model. At the bottom is the iterative solution algorithm that solves the system of equations. Based on the solution to the equations, information is provided on the operation and acquisition of the system elements and on the decision criteria outcomes. This feedback is indicated by the double arrow lines.

On the left the native loads of each utility on the west coast are represented. Long-term load growth and seasonal, daily and hourly load patterns for each native load are modeled.

All generating units on the west coast are represented with such information as minimum loads, heat rates, maintenance rates, and forced outage probabilities.

The major interregional transmission links are represented. Transmission losses are a function of loading.

All existing long-term power contracts (about 300) are represented, and a large number of generic new contracts among all parties are defined to allow the model to decide how much of each type of new contract to write among the parties.

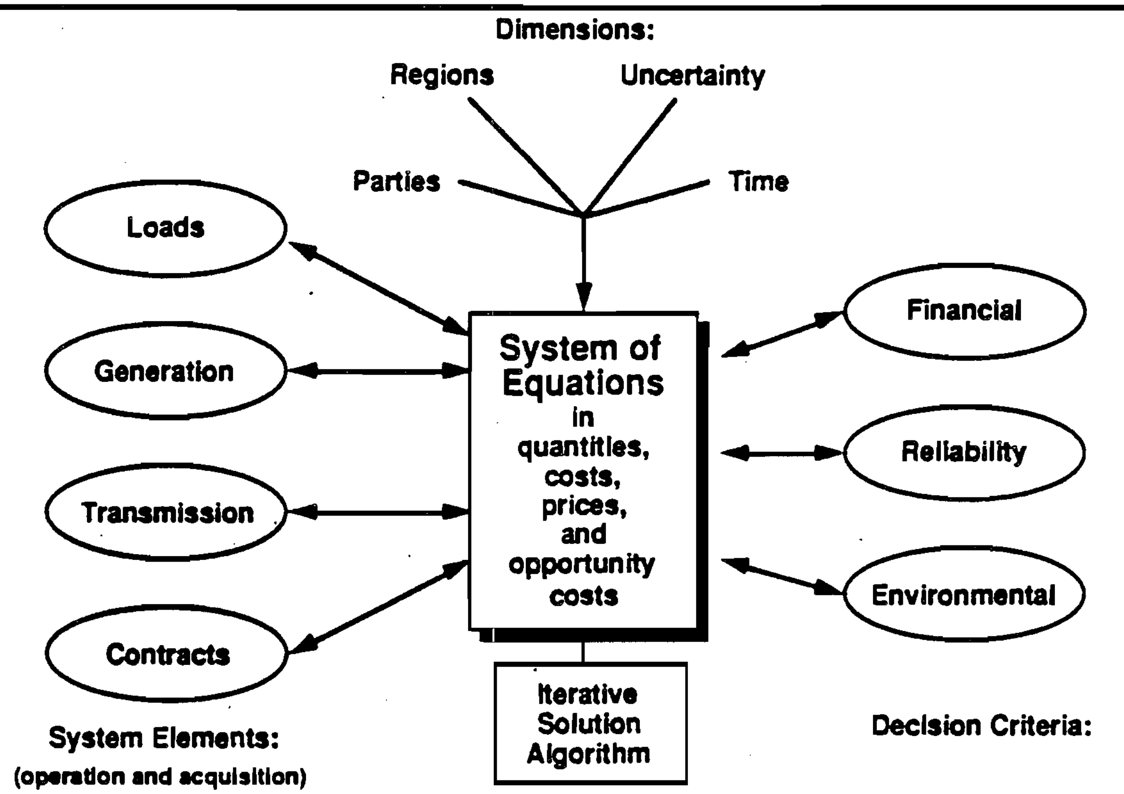



Figure 2.1 - Basic Structure of PMDAM

The financial part of the model covers most of the standard utility financial matters. The financial objective for each utility is least-cost to ratepayers. Most of the standard financial variables associated with utility operation and investment are computed.

Reliability is characterized both in terms of a peak loss-of-load probability requirement and a firm energy requirement. Firm energy capability has been the key criteria in the hydro-rich Pacific Northwest planning region and peak capability is the key criteria for the mainly thermal systems in the Pacific Southwest.

The model computes regional and west coast emissions, and has the capability to have environmental criteria affect operation and acquisition. Capability to compute Pacific Northwest fisheries and recreational impacts is currently being developed.

The basic idea behind the iterative algorithm is to find the opportunity prices that balance short- and long-term supply and demand while minimizing each party's cost of meeting native loads. A very large system of thousands of nonlinear, simultaneous equations is used to describe the system elements and decision criteria over the range of party, region, time and uncertainty dimensions. This system of equations must be solved to produce the model results. Solution of these equations requires an iterative approach. One reason an iterative solution is required is because the supply and demand for power among utilities on the west coast depends on price and price depends on the cost of suppling power at a given level of demand.

The model computes many variables of interest that can be considered model outputs. Quantities, costs, prices and opportunity prices are computed for hourly, daily, weekly, monthly and annual power related commodities such as economy energy, firm energy, firm capacity, hourly transmission services, and transmission capacity.

The level of detail in the model is variable depending on the needs applications of the model results.

At the top of Figure 2.1, four key dimensions of the model are indicated: parties, regions, uncertainty and time.

The model's simulation is carried out over time where time is dimensioned in years, months, weeks, days, and hours. The model is designed to operate over a planning horizon of up to forty years and over representative months, weeks, days and hours within each year.

The uncertainty dimension specifies the number of random games used to represent uncertainty in the market. Uncertainty about inflows, loads, fuel prices and unit availability is modeled using a Monte Carlo approach with decisions conditioned on how the uncertainty is resolved over time.

Each item in Figure 2.1 is described in more detail later in this report. This section provides a brief introduction to each item.

## 2.2. Regions, Parties, Points of Delivery and Nodes

The PMDAM model is designed to cover BPA's major power markets on the west coast of the United States. This market consists of a number of regional markets each of which is controlled by one or more utility companies who serve retail customers.

**Table 2.1 - Regions and Parties**

**BC - British Columbia**
- **BCH** - British Columbia Hydro

**PNW - Pacific Northwest (Washington, Oregon, Idaho,and Western Montana)**
- **GPUB** - Generating Public Utilities (NW)
- **PGE** - Portland General Electric
- **BPA** - Bonneville Power Administration
- **PP&L** - Pacific Power and Light
- **OIOU** - Other Investor Owned Utilities

**NC - Northern California**
- **PG&E** - Pacific Gas & Electric
- **ONC** Other Northern California Utilities

**SC - Southern California**
- **SCE** - Southern California Edison
- **LADWP** - Los Angeles Department of Water and Power
- **SDG&E** - San Diego Gas & Electric
- **OSC** - Other Southern California Utilities

**ISW - Inland Southwest (Nevada, Utah, Arizona, and New Mexico)**
- **ISW** - all utilities in the ISW region

As shown in Figure 2.2 and Table 2.1, the model divides this west coast market into five regions and thirteen parties each representing a single utility or a group of utility companies. The number of regions and parties is determined by model input data. As with many other dimensions of the model, the level of regional and party detail can be adjusted to meet the needs of the analysis. For BPA's analysis needs, Pacific Northwest detail is more important than Inland Southwest detail.

Parties in PMDAM can own resources in more than one region. In the current data base several California parties own resources in the Inland Southwest region of the model.

Figure 2.2 also shows the basic transmission network used by PMDAM. Transmission is discussed further in Section 2.9. For each transmission link in the figure, the ownership of the link by party is indicated.

As shown in Figure 2.2, the ownership of the transmission lines between the PNW and the two California regions changes at the *points of delivery* called COB (California Oregon Border) and NOB (Nevada Oregon Border). Regions are also points of delivery in PMDAM. A point of delivery is a geographic location where power is delivered according to a contract between two parties.

An important dimension used in PMDAM is called the *node* dimension. A node in PMDAM represents a single party in a single region. The node dimension is necessary because SCE, for example, owns generating resources in both the SC and ISW regions. Two nodes are then assigned in the model to SCE, one for each region. BPA owns resources only in the the PNW and is assigned only one node. Similarly, PGE is assigned one node for its resources in the PNW.

Points of delivery that are not regions such as COB and NOB are not used to define nodes. The node dimension is important because it is at a node that generation plus purchases from other nodes must balance native loads plus sales to other nodes.

## 2.3. Time Structure

Time in PMDAM is structured by year, month, week, day and hour. Many variables in the model, such as load, generation, and operating cost may vary by all five of the time dimensions. Other variables may be independent of time. Some variables, such as fuel price may

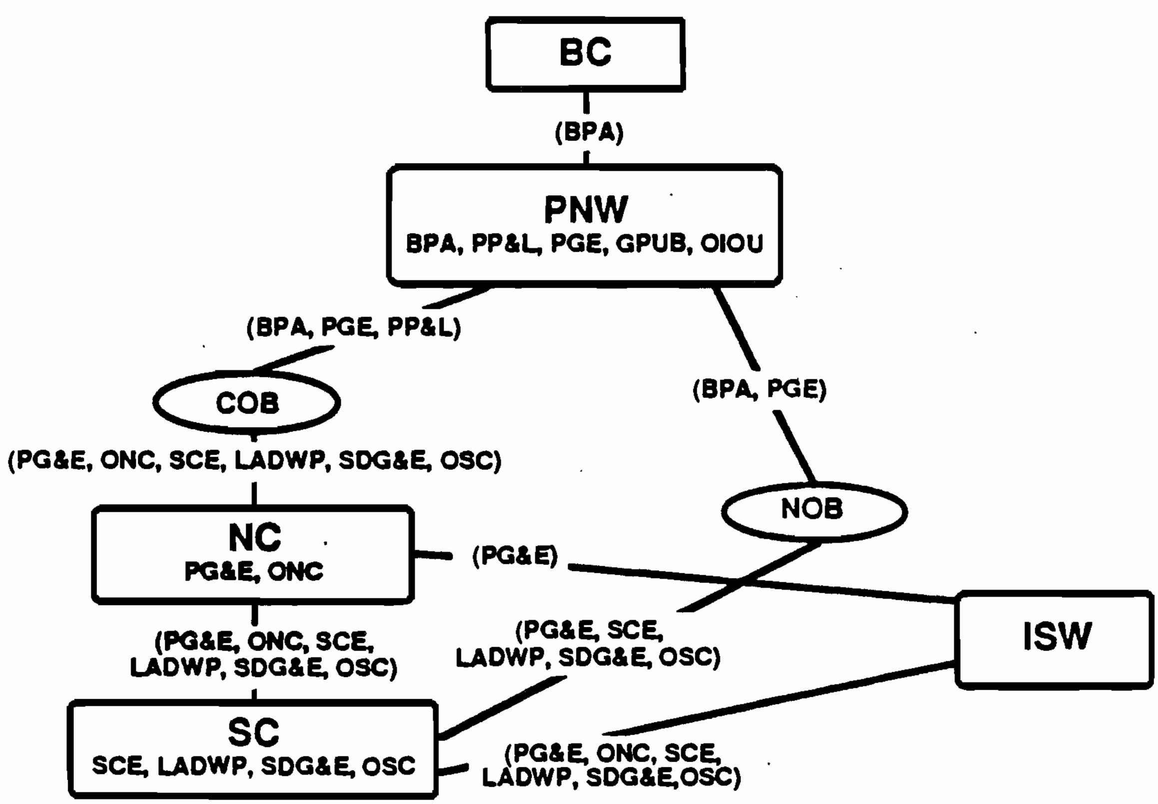



**Figure 2.2 - Regions, Parties and Points of Delivery**

vary by month and year, but not by hour, day and week.

The selection of which time dimensions to associate with each variable is a modeling decision that depends on a number of factors including (1) the sensitivity of the model results to the choice of time dimensions for a variable and (2) the logic of the model.

Different applications of the model require different degrees of time detail. For example, long-term planning applications relating to generating resource acquisition may require a planning horizon of 20 to 40 years. Short-term planning applications relating to efficient operation of the system may require only a few years of detail, but much more hourly, or monthly detail.

The cost of running the model in terms of computer time and computer disk storage increases with the amount of time detail in the model. PMDAM allows the user to select the amount of time detail appropriate to his application and allocation of computer resources.

Table 2.2 illustrates the tradeoff between time detail and model size. In this table, time detail is illustrated for four different runs of PMDAM that have been used at BPA. In the first run, the year detail is emphasized. In the second run, the month detail is emphasized. In the third run, year and hour detail are emphasized. In the fourth run, all time dimensions, except year are emphasized.

**Table 2.2 - Time Detail Vs. Size**

| | | Run | | | |
|---|---|---|---|---|---|
| Dimension | | 1 | 2 | 3 | 4 |
| Years | | 40 | 20 | 40 | 1 |
| Months | Per Year | 4 | 12 | 4 | 12 |
| Weeks | Per Month | 1 | 1 | 1 | 2 |
| Days | Per Week | 2 | 2 | 3 | 7 |
| Hours | Per Day | 2 | 2 | 24 | 24 |
| | Size | 640 | 960 | 11520 | 4032 |

The bottom row in Table 2.2 indicates the relative size of PMDAM. This size indicator is simply the product of time dimension sizes for the run. For example, run 3 will require a factor of about 11,520/640 (or, 18) times more computer resources than run 1. Other dimensions such as the number of random games and number of parties also affect model size. Generally, if the size or product of the time dimensions is doubled, then the run time and storage requirements of the model are roughly doubled.

Model input data are always expressed at the highest level of detail necessary. PMDAM automatically converts the input data to the sizes of model time dimensions chosen by the user.

Another variable affecting model size is the number of games used to represent uncertainty. A fifty game model will require about fifty times the computer storage and computation resources of a single game model.

## 2.4. Uncertainty

Explicit modeling of uncertainty is important to analysis of many power system decision problems. PMDAM currently treats the following four input variables as uncertain: hydro inflow, native load, gas price, and generating unit forced outage. These variables are critical to properly representing the operating costs of the systems, the overall system growth, and the need for a new or a different mix of resources and contracts. Other variables could be treated as uncertain without greatly increasing the computational costs of PMDAM.

### 2.4.1. Monte Carlo Approach

The Monte Carlo method of modeling uncertainty requires running the model for several games. Each game is a complete run of the model over all time dimensions, and parties. Each game is equally likely; the probability associated with each game is

$$[2.1] \quad \text{Game Probability} = \frac{1}{\text{Number of Games}}$$

For each game, samples of all uncertain variables are generated based on the probability distributions for each variable. Standard methods are used to generate random samples of a variable such that the distribution of the random samples is the same as the input probability distribution for the variable

### 2.4.2. Conditional Uncertainty

At a given time the probability distribution on a variable may depend on other uncertain variables or on the same variable in a previous time period. For example, in PMDAM regional loads depend on overall national economic variables as well as regional variables. Another example is the probability distribution on monthly hydro stream flow that depends on the previous month's flow. The probability distributions for each of the uncertain variables in the model are described later in Section 2 in the discussion of loads and generating resources.

### 2.4.3. Conditional Decisions

PMDAM models the impact of uncertainty on decisions made by parties in the power market. As uncertainty is resolved sequentially over time, operating and acquisition decisions depend on the conditional probability distributions at each decision point.

Decisions in PMDAM are based on minimizing cost to each party. The cost is measured in expected present value forward from the time of the decision. The expected value of present cost is a conditional expected value that is based on the conditional probability distributions at the time of the decision.

As a result of the conditional decision methods in PMDAM, the Monte Carlo games decisions in one Monte Carlo game depend on outcomes in all games. The results of all games are used to estimate the conditional expected values used for decisions on any given game (see Section 2.8.4.20 and 2.8.6.9).

## 2.5. Iterative Solution Algorithm

The structure of the model, and the input data define a set of simultaneous equations that represent the power market and system. Some of the equations in PMDAM represent physical constraints such as the requirement that loads and resources balance in each hour for each party. Other equations are behavioral, in that they describe how operating and acquisition decision variables vary as a function of other, sometimes uncertain, variables. These behavioral equations are developed from an optimization objective function for each party that assumes each party strives to minimize costs to its native load customers while carrying out mutually beneficial contracts with other parties. The development and solution of the set of simultaneous equations that form the model is described in more depth in Section 3.

The output variables of the model are determined by solving PMDAM's set of simultaneous equations. These variables include quantities describing operating and acquisition decisions for generating resources, contracts and transmission. The output variables also include opportunity prices. These opportunity price variables are often denoted by the symbol $\lambda$, and play a special role in the solution of the system of equations.

The solution of PMDAM's set of equations can also be interpreted as the equilibrium solution to an economic supply and demand problem. The equilibrium prices are the opportunity prices and the equilibrium quantities describe the operation and acquisition of generation and contracts by the parties in the model.

The system of equations in PMDAM is solved using an iterative algorithm. This iterative algorithm can be illustrated by a simplified single hour example. For this example only, the interactions between this hour and any other hour will be ignored.

Consider a single node (party in a given region) power system with thermal generation, import purchases, export sales and native load. For a single hour of a game, the operation of this system requires that total generation equals total load and that the cost of serving the native load be the lowest possible. This hourly load/resource balance equation is written as follows:

$$[2.2]\quad \text{surplus}(\lambda) = \text{generation}(\lambda) - \text{native load}(\lambda) - \text{sales}(\lambda) + \text{purchases}(\lambda)$$

where

$\lambda$ is the hourly energy opportunity price for the node,

surplus($\lambda$) is the excess supply over demand at a given estimate of the hourly energy opportunity price (At the solution, surplus($\lambda$) must equal zero.),

generation($\lambda$) is the total generation from all generating resources at the node at a given estimate of the hourly energy opportunity price,

native load($\lambda$) is the hourly firm load at the node, which is always served except in outage situations when insufficient generation and purchases are available,

sales($\lambda$) is the total of all sales to all other nodes at a given estimate of the hourly energy opportunity price.

purchases($\lambda$) is the total of all purchases from all other nodes at a given estimate of the hourly energy opportunity price.

The algorithm to find the least-cost operation of resources and contracts with zero surplus in this hour is diagramed in Figure 2.3 and stated below.

### Simplified Iterative Algorithm

**1. Estimate $\lambda$,**
**2. Compute surplus($\lambda$) from Equation [2.2],**
**3. If surplus($\lambda$) = 0 then STOP,**
**4. Otherwise, set $\lambda = \lambda - \alpha$ surplus($\lambda$) and return to Step 2.**

In this algorithm $\alpha$ is an arbitrary small number, adjusted to achieve convergence of the series of surpluses produced by the algorithm to zero surplus. Too large a value for $\alpha$ will cause successive values of the surplus and $\lambda$ to oscillate without converging to zero surplus solution. Too small a value of $\alpha$ will cause successive values of the surplus and $\lambda$ to move very slowly towards a zero surplus, requiring more iterations than necessary. Procedures for setting $\alpha$, have evolved through experimentation with the model.

In simple terms, the algorithm proceeds as follows:

1. Estimate, the hourly energy opportunity price $\lambda$. Any initial value of $\lambda$ will work, but a good estimate will reduce the number of iterations required to achieve a solution. Suppose the initial estimate of $\lambda$ is 20 mills per kWh.
2. Given $\lambda = 20$, dispatch all generating units or portions of units and all purchases costing less than 20 and serve only those sales loads worth more than 20. The native load is always served except at very high opportunity prices. Add up the generation less native load less sales plus purchases according to Equation [2.2]. The result is the surplus energy (a negative surplus is a deficit) on the current iteration.
3. If the surplus is near zero then the initial estimate is the solution.
4. If the surplus is positive, then decrease $\lambda$. If the surplus is negative (a deficit), then increase $\lambda$. A large surplus requires a larger decrease in $\lambda$ than a small surplus. $\alpha$ defines the desired rate of change of $\lambda$ with respect to the surplus. If the surplus at $\lambda = 20$ is 100 mW and $\alpha = 0.001$ then the new $\lambda$ is

[2.3] $\lambda = 20 - 100 \times 0.001 =$
$20 - 0.1 =$
$19.9$ mills/kWh.

After several iterations a solution with surplus = 0 will be found. Variations of this algorithm are used to treat special cases where this simplified algorithm would not find a solution (see Section 3.2.4).

Why does this algorithm result in the least-cost solution (minimal net cost of serving native load)? From the way the algorithm is constructed, at the solution no additional energy from generation or purchases that would cost less than $\lambda$ is available and no additional sales opportunity worth more than $\lambda$ is available. Thus, the solution is a least-cost solution.

Figure 2.4 shows the hourly energy opportunity price for three major west coast parties on a typical 1991 summer day. Hourly energy opportunity prices are often called *system lambdas* by industry specialists. The results in Figure 2.4 were based on model input assumptions prepared in early 1990. The results

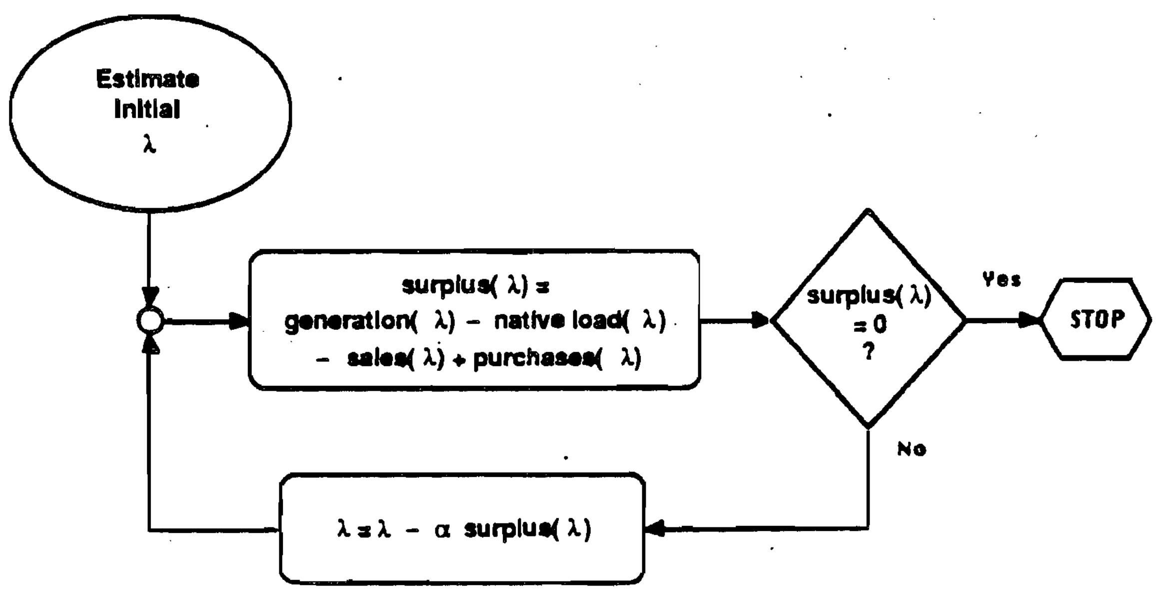



**Figure 2.3 - Simplified Iterative Algorithm**

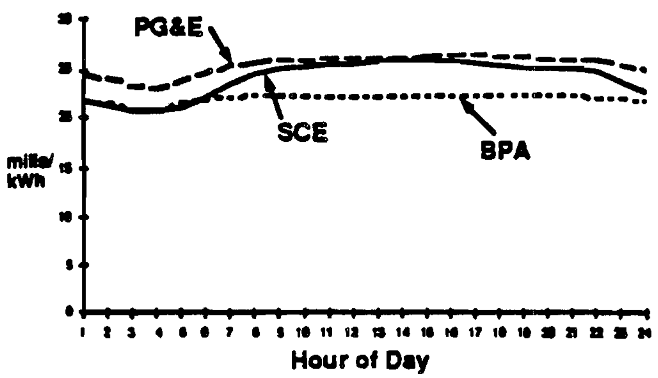



**Figure 2.4 - System Lambdas for Typical 1991 Summer Weekday**

can vary significantly depending on hydro inflows, loads, and natural gas price outcomes.

In Figure 2.4, BPA, a PNW hydro dominated, winter peaking utility has a relatively flat system lambda over the twenty-four hour period. PG&E, a Northern California utility and SCE a Southern California are both summer peaking, mainly thermal utilities. Both of these utilities have greater on- versus off-peak differences in system lambdas. SCE has lower off-peak system lambdas because of its greater access to low-cost, off-peak coal generation from the Inland Southwest region.

The difference between the on-peak system lambdas for BPA and the California utilities reflects the difference in cost needed to overcome losses, transmission costs and the opportunity prices of limited transmission capacity to transmit power on-peak from the PNW to California. Transmission losses, costs, and opportunity prices are discussed in Section 2.9.

Figure 2.5 shows the system lambdas for the same three parties on a typical winter weekday in the year 2015. The lambdas are much higher than in Figure 2.4 because of escalation in fuel prices. Here, BPA off-peak system lambdas exceed the California system lambdas. BPA system lambdas also reflect the double morning and evening winter peak caused by the PNW winter electric heating load. Off-peak imports of power from California utilities are supported by the higher BPA off-peak lambdas.

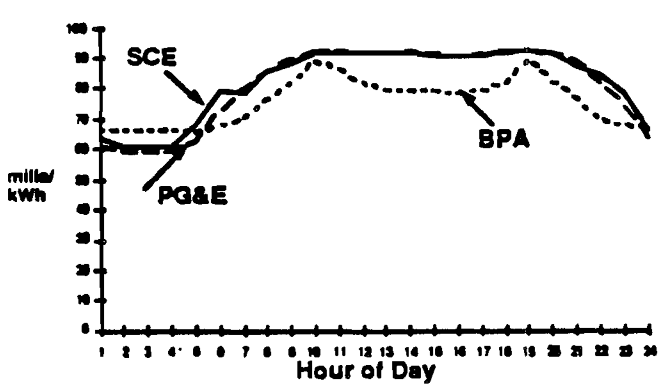



**Figure 2.5 - System Lambdas for Typical 2015 Winter Weekday**

## 2.6. Opportunity Prices

An opportunity price in PMDAM is associated with each constraint in the model. The hourly energy opportunity price $\lambda$ described in Section 2.5 is the opportunity price associated with the hourly node energy load/resource balance constraint. Other operating and acquisition $\lambda$'s are associated with other constraints in the model. These other opportunity prices perform a role similar to the hourly energy opportunity prices in satisfying other constraints in the model. A complete list of the opportunity prices and associated constraints in PMDAM is provided in Appendix B.

The term *opportunity price* reflects the change in cost to native load customers given a unit change in the constraint. In other words, a one kWh increase in native load in this hour would result in a cost increase of $\lambda$ to native load customers. Referring to Equation [2.2], this cost increase reflects the lost opportunity in selling one kWh of energy elsewhere, or generating or purchasing one kWh less energy. The theoretical basis for opportunity prices is discussed further in Section 3.

Opportunity prices must be distinguished from the accounting cost to customers based on rate making requirements. The rate making requirements may or may not consider opportunity prices in setting rates.

In this section we will briefly describe each of these constraints and the opportunity price $\lambda$ associated with each constraint. The opportunity prices are divided into two classes: operating opportunity prices and planning or acquisition opportunity prices.

### 2.6.1 Operating Opportunity Prices

Operating system opportunity prices are associated with model constraints that are imposed on an operating basis.

#### 2.6.1.1. Hourly Energy Opportunity Price

The hourly energy opportunity price, ( hereafter $\lambda_e$), introduced in the discussion of the iterative algorithm in Section 2.5 is associated with the hourly *node* energy load/resource balance constraint. For each party, one node is assigned to each region in which the party owns generating resources or serves loads. The hourly node energy load/resource balance constraint is

$$[2.4]\quad \text{generation}(\lambda_e) - \text{native load}(\lambda_e) - \text{sales}(\lambda_e) + \text{purchases}(\lambda_e) = 0$$

where the terms in this equation were defined in Equation [2.2].

The terms in Equation [2.4] are written as a function of the hourly energy opportunity price, $\lambda_e$. In fact, many other opportunity prices also influence the terms in [2.4]. For example, generation is directly a function of $\lambda_e$ and also the maintenance, hydro, pumped storage, firm capacity, and firmness of energy opportunity prices described below. Indirectly all opportunity prices may affect generation in a given hour. The hourly energy opportunity price is special to the hourly energy load resource balance constraint. It specifies the change in cost per unit change in this constraint due to a change in any term in the constraint.

The node hourly energy opportunity price, $\lambda_e$, is the highest price, in mills/kWh, the party should pay for additional energy generated or purchased in that hour and in the region defined by the node. $\lambda_e$, is also the lowest price the party should accept for additional energy sold in that hour and in the region defined by the node.

Finally, under outage conditions, $\lambda_e$, is the highest price the party should pay for additional energy used to avoid a native load outage in that hour and in the region defined by the node. Under outage conditions, $\lambda_e$, is also the lowest outage price the party should accept for any native load outage in that hour and in the region defined by the node.

#### 2.6.1.2. Hourly Transmission Opportunity Price

The hourly transmission opportunity price, $\lambda_t$, is associated with the hourly balance of loads and transmission capacity on a single owner's share of a single link of the transmission system. The balance of loads and resources on a transmission link must be measured at the same point on the transmission line so that transmission losses are properly considered.

$$[2.5]\quad \text{transmission load}(\lambda_t) \leq \text{transmission capacity}$$

The hourly transmission owner's opportunity price, $\lambda_t$, is the highest price, in mills/kWh, the owner should pay for additional transmission capacity purchased only for that hour and for that owners share of a transmission link. $\lambda_t$, is also the lowest price the owner should accept for transmission capacity sold for use in that hour and for that transmission link.

#### 2.6.1.3. Annual Maintenance Opportunity Price

The annual maintenance opportunity price, $\lambda_M$, is associated with the annual constraint that the total maintenance of a generating resource over all months of a year equal the annual maintenance requirement.

$$[2.6]\quad \sum_{\text{months}} \frac{\text{monthly maintenance fraction }(\lambda_M)}{\text{number of months}} = \text{annual maintenance fraction}$$

The annual maintenance opportunity price, $\lambda_M$, is the highest price, in \$/kW-yr, the owner should pay to reduce the annual maintenance requirement of a generating resource in that year. $\lambda_M$, is also the lowest price the owner should accept to increase the annual maintenance requirement of a generating resource in that year.

#### 2.6.1.4. Contract Energy Opportunity Prices

The contract energy opportunity prices are associated with various contract constraints on the delivery of contract energy. Firm energy contracts may have annual, monthly, weekly and daily limits on energy delivery. The contract constraints actually apply to a link of a contract.

Complex contracts may be composed of several links. For example, a capacity contract for delivery of energy over peak hours and the return of that energy over the off-peak hours, would have two links; a *delivery* link and a *return* link.

Contract links should not be confused with transmission links. A contract link is a contractual agreement between two parties, that may use more than one transmission link. A transmission link is an electrical connection between two points of delivery.

The annual contract link energy opportunity price, $\lambda_{la}$, is associated with the following constraint:

$$[2.7] \text{ annual link energy } (\lambda_{la}) \leq \text{ annual link energy limit}$$

The monthly contract link energy opportunity price, $\lambda_{lm}$, is associated with the following constraint:

$$[2.8] \text{ monthly link energy } (\lambda_{lm}) \leq \text{ monthly link energy limit}$$

The weekly contract link energy opportunity price, $\lambda_{lw}$, is associated with the following constraint:

$$[2.9] \text{ weekly link energy } (\lambda_{lw}) \leq \text{ weekly link energy limit}$$

The daily contract link energy opportunity price, $\lambda_{ld}$, is associated with the following constraint:

$$[2.10] \text{ daily link energy } (\lambda_{ld}) \leq \text{ daily link energy limit}$$

Firm capacity contracts require that any energy delivered to the buyer be returned to the seller within 24 hours. The capacity contract link energy opportunity price, $\lambda_{lc}$, is associated with the following constraint:

$$[2.11] \text{ daily link return energy } (\lambda_{lc}) = \text{ daily link energy } (\lambda_{lc})$$

The daily link energy in the above equation is the energy on the delivery link of the capacity contract and the daily link return energy is the energy on the return link of the capacity contract.

Each of the contract link energy opportunity prices in Equations [2.7] to [2.11] is the highest price, in mills/kWh, the buyer should pay to increase the quantity of energy available under the constraint associated with the price. Each of the contract link energy opportunity prices is also the lowest price the seller should accept to decrease the quantity of energy available under the constraint associated with the price.

### 2.6.1.5. Pumped Storage Energy Opportunity Price

The pumped storage energy opportunity price, $\lambda_S$, is determined by the upper and lower stored energy limit opportunity prices. This opportunity price is computed on an hourly basis.

The upper stored energy limit opportunity price, $\lambda_{Su}$, is associated with the following constraint:

$$[2.12] \text{ stored pumped energy } (\lambda_{Su}) \leq \text{ upper pumped energy limit}$$

The upper stored energy limit opportunity price, $\lambda_{Su}$, in mills/kWh, is the highest price the storage resource owner should pay to increase the storage capacity of the resource for that one hour.

Similarly, the lower stored energy limit opportunity price, $\lambda_{Sl}$, is associated with the following constraint:

$$[2.13] \text{ stored pumped energy } (\lambda_{Sl}) \geq 0$$

The pumped storage energy opportunity price, $\lambda_S$, is computed from the two stored energy limit opportunity prices as follows:

$$[2.14] \lambda_S = \lambda_S \text{ (hour + 1) } - \lambda_{Su} + \lambda_{Sl}$$

The pumped storage energy opportunity price, $\lambda_S$, is the highest price the storage resource owner should pay to increase the stored energy of the resource for that one hour. The pumped storage energy opportunity price, $\lambda_S$, also is the lowest price the storage resource owner should accept for energy generated by the resource in that one hour.

Further detail on the interpretation of the pumped storage constraints and opportunity prices is provided in Section 2.8.3.

### 2.6.1.6. Hydro Stored Energy Opportunity Price

The hydro stored energy opportunity price, $\lambda_H$, is determined by the upper and lower hydro stored energy limit opportunity prices. This opportunity price is computed on a monthly basis.

The upper hydro stored energy limit opportunity price, $\lambda_{Su}$, is associated with the following constraint:

[2.15] stored hydro energy ($\lambda_{su}$) $\leq$ upper hydro energy limit

The upper hydro stored energy limit opportunity price, $\lambda_{su}$, in mills/kWh, is the highest price the hydro resource owner should pay to increase the storage capacity of the hydro resource for that month.

Similarly, the lower stored energy limit opportunity price, $\lambda_{sl}$, is associated with the following constraint:

[2.16] stored hydro energy ($\lambda_{sl}$) $\geq$ lower hydro energy limit

The lower hydro stored energy limit opportunity price, $\lambda_{sl}$, in mills/kWh, is the highest price the hydro resource owner should pay to reduce the lower storage capacity limit of the hydro resource for that month.

The hydro storage energy opportunity price, $\lambda_H$, is computed from the two stored energy limit opportunity prices as follows:

[2.17] $$\lambda_H = \lambda_H\,(\text{month} + 1) - \lambda_{su} + \lambda_{sl}$$

The hydro energy opportunity price, $\lambda_H$, is the highest price the hydro resource owner should pay to increase the stored energy of the hydro system for that one month. The hydro energy opportunity price, $\lambda_H$ also is the lowest price the hydro resource owner should accept for energy generated by the hydro resource in that month.

Further detail on the interpretation of the hydro storage constraints and opportunity prices is provided in Section 2.8.4.

### 2.6.1.7. Hydro Minimum Discharge Opportunity Price

The hydro minimum discharge opportunity price, $\lambda_D$, is associated with the constraint on minimum average discharge of hydro energy as follows:

[2.18] hydro monthly discharge ($\lambda_D$) $\geq$ minimum monthly hydro discharge

This opportunity price is computed on a monthly basis.

The hydro minimum discharge opportunity price, $\lambda_D$, is the highest price the hydro resource owner should pay to decrease the minimum monthly discharge for one month.

### 2.6.1.8. Hydro Energy Variability Opportunity Prices

The hydro energy hourly variability opportunity price, $\lambda_{vh}$, is determined by the hydro energy daily variability opportunity price. Daily variability of hydro energy discharge is a measure of the variation in hourly discharge compared to the average discharge for the day..

The hydro energy daily variability opportunity price, $\lambda_{vd}$, is associated with the following constraint:

[2.19] daily variability ($\lambda_{vd}$) $\leq$ maximum hydro daily variability

where

$$\text{daily variability} = \frac{\text{daily standard deviation discharge}}{\text{daily average discharge}}$$

The hydro energy hourly variability opportunity price is derived from the daily variability price as follows:

[2.20] $$\lambda_{vh} = \lambda_{vd} \cdot \frac{\partial\ \text{daily variablity}}{\partial\ \text{hydro hourly discharge}}$$

Further detail on the interpretation of the hydro variability constraints and opportunity prices is provided in Section 2.8.4.

### 2.6.1.9. Emissions Opportunity Prices

The emissions opportunity price, $\lambda_g$, is associated with the following constraint on the discharge of air and other emissions from electric power facilities:

[2.20a] Emissions ($\lambda_g$) $\leq$ Emissions Limit

where emissions by type and region are accumulated for all generating resources.

This emissions limit can be enforced on a monthly basis by emission type and by region or air basin or for the West Coast as a whole. Emission types include such emissions as carbon emissions contributing to CO2 buildup and global warming, sulphur dioxides, nitrogen oxides and particulates. Emission constraints and the development of emissions opportunity prices are described in more detail in Section 2.13.

The emissions opportunity price, $\lambda_g$, is computed on a monthly basis by emissions type and region.

For each generating resource a derived generation emissions opportunity price, $\lambda_G$, is computed as follows:

**[2.20b]** $\lambda_G =$

$$\sum_{i=1}^{MAXEMS} \lambda_{gi} \times \text{Resource Emission Rate}_i$$

where

Resource Emission Rate is the quantity of the $i^{th}$ type of emissions ( i.e. tons of Carbon ) per kWh of generation by a given generating resource.

The generation emissions opportunity price, $\lambda_G$ specifies the emissions opportunity price in mills per kWh of generation by each resource. $\lambda_G$ is used in the dispatch of generating units and also affects the acquisition of generating units. $\lambda_G$ is the highest price a generating resource owner should pay to be allowed to increase the emissions discharges by the amounts required to generate one additional kWh of electricity from a generating resource. $\lambda_G$ is also the lowest price a generating resource owner should accept to agree to decrease the emissions discharges by the amounts required to generate one less kWh of electricity from a generating resource.

### 2.6.2 Acquisition Opportunity Prices

Acquisition opportunity prices are used on a planning basis in PMDAM to insure that reliability criteria are met in planning the acquisition of generating resources and the acquisition and sale of firm contracts.

#### 2.6.2.1. Loss of Load Probability Opportunity Price

The loss of load probability (LOLP) is a measure of the likelihood that peak loads will not be served because of insufficient generation and purchases.

In PMDAM each party is a member of a reliability pool. A loss of load probability is computed both for the pool and for the party.

The annual pool LOLP opportunity price, $\lambda_A$, is associated with an annual constraint on pool LOLP. The constraint is as follows:

$$\text{[2.21] annual pool LOLP } (\lambda_A) \leq \text{ annual pool LOLP requirement}$$

The annual pool LOLP opportunity price, $\lambda_A$, is the highest price the pool should pay to reduce the annual pool LOLP for one year. The annual pool LOLP opportunity price, $\lambda_A$, is also the lowest price the pool should pay to increase the annual pool LOLP requirement for one year.

The monthly party LOLP opportunity price, $\lambda_L$, is associated with a monthly constraint on party LOLP. The constraint is as follows:

$$\text{[2.22] monthly party LOLP } (\lambda_L) = \text{ monthly party average LOLP } (\lambda_L)$$

The monthly party average LOLP is the average LOLP for the parties in the pool.

The monthly pool LOLP opportunity price, $\lambda_L$, is the highest price the pool should pay to reduce the monthly party LOLP for one month.

Further detail on the interpretation of LOLP constraints and opportunity prices is provided in Section 2.12.2.

#### 2.6.2.2. Monthly Firm Capacity Opportunity Prices

The monthly firm capacity opportunity prices are derived from the LOLP opportunity prices described in Section 2.6.2.1. The firm capacity opportunity price depends on the characteristics (size and outage probability rate) of the capacity.

The monthly firm capacity opportunity price, $\lambda_r$, for a generating resource is given by

$$\text{[2.23] } \lambda_r = \lambda_A \frac{\partial \text{ annual pool LOLP}}{\partial \text{ resource capacity}} + \lambda_L \frac{\partial \text{ monthly party LOLP}}{\partial \text{ resource capacity}}$$

where the partial derivative terms are resource and party specific.

The monthly firm capacity opportunity price, $\lambda_r$, is the highest price, in \$/kW-yr, the owner should pay for additional quantities of nameplate capacity of a resource for this month.

The monthly firm contract link capacity opportunity price, $\lambda_c$, is given by

[2.24] $$\lambda_c = \lambda_A \frac{\partial \text{ annual pool LOLP}}{\partial \text{ link capacity}} + \lambda_L \frac{\partial \text{ monthly party LOLP}}{\partial \text{ link capacity}}$$

where the partial derivative terms are contract link specific.

The monthly firm contract link capacity opportunity price, $\lambda_c$, is the highest price, in \$/kW-yr, the owner should pay for additional quantities of contract link capacity for this month. The monthly firm contract link capacity opportunity price, $\lambda_c$, is also the lowest price the owner should accept for sale of additional quantities of contract link capacity for this month.

It is useful to also compute the opportunity price on perfectly reliable and fully maintained capacity. The monthly firm perfect capacity opportunity price, $\lambda_C$, is given by

[2.25] $$\lambda_C = \lambda_A \frac{\partial \text{ annual pool LOLP}}{\partial \text{ perfect capacity}} + \lambda_L \frac{\partial \text{ monthly party LOLP}}{\partial \text{ perfect capacity}}$$

The party monthly firm capacity opportunity price, $\lambda_C$, is the highest price, in \$/kW-yr, the party should pay for additional quantities of perfectly reliable and fully maintained resource or contract capacity purchased only for that month. $\lambda_C$, is also the lowest price, in \$/kW-yr, the party should accept for additional quantities of perfectly reliable and fully maintained resource or contract capacity sold only for that month.

### 2.6.2.3. Annual Energy Firmness Opportunity Price

The party annual energy firmness opportunity price, $\lambda_E$, is associated with a reliability constraint on each party, that its *annual firm* generation and import purchases equal or exceed it *annual firm* native load and export sales. This constraint is given by

[2.26] generating firm energy
+ contract firm energy
- native firm load
- contract firm load = 0

The party annual energy firmness opportunity price, $\lambda_E$, is the highest price, in \$/kW-yr, the party should pay to convert a given schedule of non-firm energy purchases or generation to the same schedule of firm energy purchases in that year. $\lambda_E$, is also the lowest price, in \$/kW-yr, the party should accept to convert a given schedule of non-firm energy deliveries to the same schedule of firm energy deliveries in that year.

### 2.6.2.4. Monthly Firm Transmission Opportunity Price

The link monthly firm transmission opportunity price, $\lambda_T$, is associated with the constraint that the committed capacity of the owner's share of a transmission link not exceed the rated firm capacity of the owner's share of a transmission link. The committed capacity includes capacity dedicated to the owner's power sales and purchase contracts as well as transmission capacity sold to other parties. This constraint is written as follows:

[2.27]

committed link transmission ($\lambda_T$) ≤
link transmission capacity

The link monthly firm transmission opportunity price, $\lambda_T$, is the highest price, in \$/kW-yr, the owner should pay for additional transmission capacity purchased only for that month and for that transmission link. $\lambda_T$, is also the lowest price the owner should accept for firm transmission capacity sold for use in that month and for that transmission link.

## 2.7. Native Loads

Loads in PMDAM are of two kinds. Native loads and contract loads. Native loads are those loads served directly by a party. Contract loads are sales to other parties in the model. In practice some native loads may be served by contract, but for the purpose of modeling we define native loads as sales to parties not represented in the model. In this section, only native loads are discussed.

### 2.7.1. Types of Native Loads

The model allows the specification of an arbitrary number of native loads for each party. For each native load, the expected annual, load shapes, uncertainty and the cost of not serving the load can be defined. Also, associated with each native load is a firm peak demand and firm energy load requirement.

The modeling of loads can be illustrated by the case of BPA, where the native loads currently represented are

1. BPA Firm Load (BPAFRM) - Federal agency loads, United States Bureau of Reclamation loads, small public utility loads, nongenerating public utility loads, and associated transmission losses.
2. Directly Served Industries Firm Load (DSIFRM) - The one quartile of the mainly aluminum smelter load served as both a firm capacity and a firm energy load.
3. Directly Served Industries Firm Load with Peak Restriction Rights (DSI2Q) - The two quartiles (one half) of the mainly aluminum smelter load served as a nonfirm capacity but a firm energy load.
4. Directly Served Industries Top Quartile Load (DSINFM) - The one quartile of the mainly aluminum smelter load served as both a nonfirm capacity and a nonfirm energy load.

Other BPA loads modeled as contracts include sales to the generating public utilities and private utilities in the PNW and extraregional sales and obligations to parties in British Columbia and California.

### 2.7.2. Expected Annual Load

Native loads are specified to the model as a forecasted series of annual energy load by type of load for each year in the model horizon. This forecast of annual energy load should represent the expected value of the forecast for each future year, as this expected value is used as a base for adjusting the load for uncertainty.

### 2.7.3. Load Shapes

PMDAM requires modeling of load with hourly detail. The long-term forecast of loads is in terms of average annual loads. Load shape tables based on historical data are used to compute hourly loads from the annual average loads.In the model, all loads are measured in average megawatts of energy over a given period of a year, month, day, or hour. A monthly load shape table specifies the average monthly load for each month of the year as a multiplier on the average annual load. These monthly multipliers may be less or greater than 1.0 but must, by definition, average 1.0 over the year.

Figure 2.5 illustrates the application of load shapes to calculate each type of native hourly load. At the left in the figure, the annual load is provided. This annual load is multiplied by the monthly load shape multiplier for each month of the year to give the average monthly load. This process is repeated at the daily and the hourly level to compute average daily and hourly loads. The end result of this process is a load in every hour of the year.

The historical multipliers are different for each native load. The daily multipliers vary by month and day of week. The hourly multipliers vary by month, day of week and hour. At least five years of hourly historical data were available for most loads. In some cases where data were not available, load shapes for similar loads were used as an approximation.

In modeling resource and contract acquisition it is necessary to know the expected highest hourly or peak load for each month of the year. The peak monthly load is computed from the average monthly load using a monthly peak multiplier. This monthly peak load is used in calculating the loss of load probability for the party. This peak multiplier could be computed using the largest product of the daily and hourly multipliers for the month. But, if the historical data is inadequate or assumptions as to the definition of the peak vary, it is useful to provide the peak multiplier as a separate input.

The current load shapes in PMDAM do not vary by year. So changes in load shapes over time will not be modeled except to the extent that overall system load shapes will change as the annual loads grow at different rates. The load shape logic can be modified to permit changes in load shapes over years.

### 2.7.4. Load Uncertainty

Three types of native load uncertainty are modeled.

#### 2.7.4.1. Load Growth and Annual Load Uncertainty

(to be completed)

#### 2.7.4.2. Daily Load Uncertainty

(to be completed)

### 2.7.5. Load Price Elasticity

Presently, native loads in PMDAM are insensitive to price except as indicated in the discussion of unserved and nonfirm loads which follows. Native load price elasticity can be added to PMDAM because of the economic equilibrium methodology employed by the model.

The difficult aspect of modeling load price elasticity is accurately modeling the costs and ratemaking process which yield retail power rates. It is these rates that affect native loads rather than opportunity prices. PMDAM provides a preliminary capability to model the rate making process. As this capability and the underlying cost data are improved, it will be a straightforward matter to incorporate price elasticity on native loads.

### 2.7.6. Unserved and NonFirm Load

As result of uncertainty in loads, generating unit availability, hydro flows, fuel prices and other potential constraints, it may not be possible or desirable to serve all native loads.

For each native load an outage price is specified in mills per kWh. If the hourly energy opportunity price $\lambda_e$ in a given hour and for the node (party in a region) associated with the load is greater than the outage price, then the load may be partially or fully curtailed.

For nonfirm loads, the outage price can be set at the rate for the load, or at a higher value as policy considerations may require. Firm loads are generally assigned a relatively high outage price. The priority assigned to each firm and nonfirm load is controlled by assignment of the outage prices.

If the hourly energy opportunity price $\lambda_e$ exceeds the outage price for a load then the

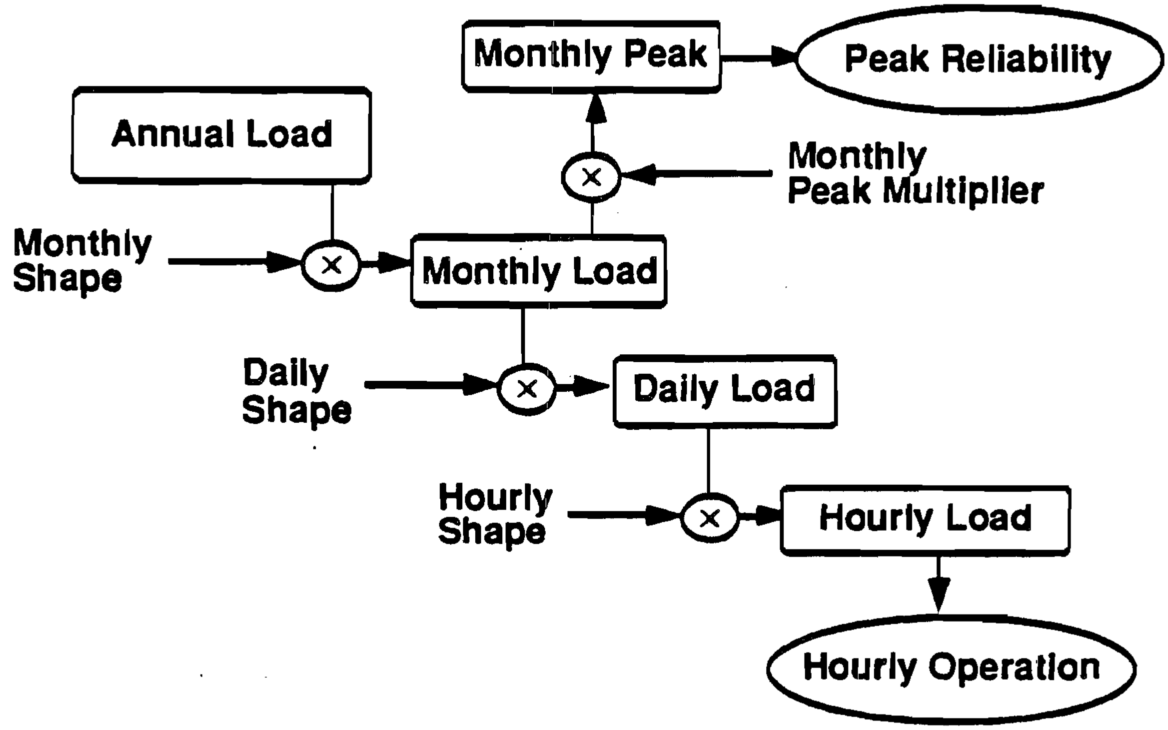



Figure 2.5 - Application of Native Load Shapes

fraction of the load curtailed is modeled as a function of the amount by which the $\lambda_e$ exceeds the outage price. Thus,

[2.28] load fraction curtailed =

$$(\lambda_e - \text{outage price}) \times \text{outage slope}$$

for

$$\text{outage price} < \lambda_e < \text{upper outage price}$$

where

outage price is the price above which load curtailment begins

$\lambda_e$ is the hourly node opportunity price,

outage slope = $\dfrac{1.0}{\text{upper outage price} - \text{outage price}}$,

upper outage price is the price above which load curtailment is 100%.

In hours when the resource supply is low and loads are high, the opportunity price, $\lambda_e$, will be adjusted until a balance is achieved. As necessary, nonfirm loads with the lowest outage price will be curtailed first. If power can be purchased from other parties at less than the outage price, this lower purchase price will be reflected in the equilibrium opportunity price and curtailment will be avoided.

Firm loads with higher outage prices will be curtailed last and only after all economic purchase opportunities have been exhausted at the equilibrium opportunity price for the hour.

## 2.8. Generation

Generating resource economics play a crucial role, even in applications of PMDAM focused on marketing. Modeling of resource acquisition and operating economics is therefore an important task for this model. The emphasis here is on those aspects of generating resources that affect the overall market for resources and contracts and not on other aspects of generating resources that may have little effect on the overall market.

All important categories of generating resources are represented in PMDAM. The modeling of generating resources emphasizes resource acquisition and operating economics and limits.

Four categories of resources are represented:

1. Thermal resources that consume a fuel and are dispatch under utility control.
2. Storage resources that are recharged by electricity and have limited storage capacity.
3. Hydro resources that consume no fuel but have limited and uncertain energy capability, limited storage capacity, and various restrictions on operation.
4. Nondispatchable resources such as cogeneration, conservation, wind, and solar resources whose dispatch is not utility controlled.

The representation of the operation of each of these four categories of resource differs. The representation of the acquisition of each resource category is the same.

### 2.8.1. Resource Operation

The operation of resources is determined on an hourly basis in the model. Because each hour is modeled in sequence, the model can be called a *chronological dispatch* model. This is in contrast to load duration curve dispatch models that simplify the modeling of resource operation by reordering the hours and loads into the form of a load duration curve.

Figure 2.5asummarizes the calculation of the generation by a resource in a given hour. The resource hourly generation by each resource is computed as the product of several factors as follows:

[2.28a] Resource Hourly Generation =

Resource Nameplate Capacity ×

Monthly Capacity Fraction ×

(1 - Monthly Maintenance Fraction) ×

Weekly Commitment Fraction ×

(1 - Daily Forced Outage Fraction) ×

Generation Operation Fraction

where

Resource Hourly Generation is the hourly generation in megawatts of a given generating resource at a node (party in a region),

Resource Nameplate Capacity is the total rated generating capacity of a given generating resource at a node.,

Monthly Capacity Ratio is the ratio of resource nameplate capacity in a month. to resource nameplate capacity,

Monthly Maintenance Fraction is the fraction of monthly capacity dedicated to scheduled maintenance for the month,

Weekly Commitment Fraction is the fraction of monthly available capacity committed to at least the minimum operating level for the week,

Daily Forced Outage Fraction is the fraction of weekly available capacity not available because of forced outage, Generation Operation Fraction is the fraction of daily available capacity operated in a given hour.

In describing how resource operation is modeled, four aspects of generating resource operation are common to all categories of resources:

1. Unit Aggregation
2. Maintenance
3. Forced Outage
4. Net Operating Benefits

### 2.8.1.1. Aggregation of Units

To reduce the computer requirements for PMDAM it is useful to aggregate or group together generating units with common characteristics. In the PMDAM input data set each individual generating unit owned by each party in the model is identified. Then, the capacity and other parameters describing the units are merged into an equivalent set of generating units with the total capability of the individual units and average operating parameters such as heat rate and forced outage rate.

Currently generating units are aggregated into the following twelve types: hydro, nuclear, coal, biomass, geothermal, boiler, combined cycle turbine, single cycle turbine, cogeneration, wind/solar, pumped storage and conservation. The list of resource types used in the model is easily changed.

Each party, may own each type of generating resource in any region, although most own resources in only one region.

For some applications of the model, less aggregation may be desirable. For example, in modeling environmental effects, it would be useful to aggregate resources by air basin.

The capability to run the model with certain units dispatched individually would be useful in some studies. Individual unit dispatch would better represent the impacts of operating limits and other operating factors on the system. The development of individual unit dispatch capability is planned for PMDAM. The capability to aggregate units for other studies

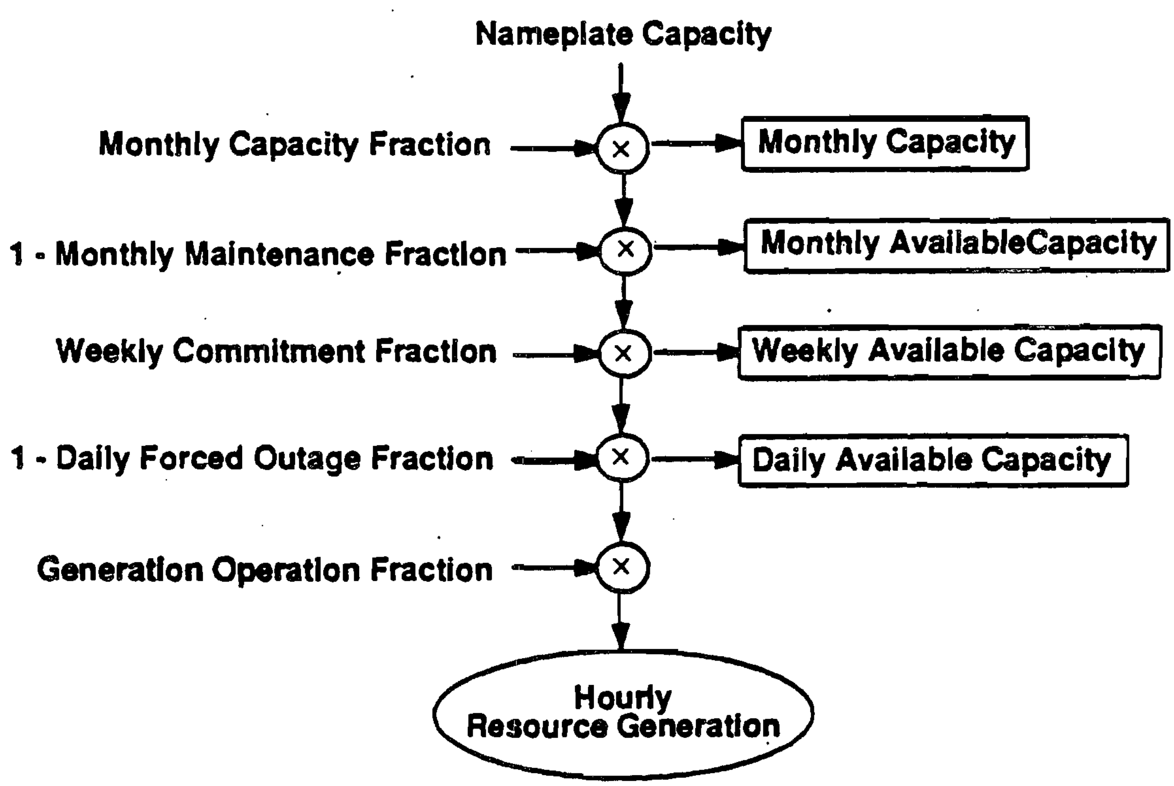



**Figure 2.5a: Calculation of Resource Hourly Generation**

will be retained.

#### 2.8.1.2. Maintenance

Scheduling of maintenance is important in PMDAM because changes in contracts between regions may shift the need for capacity and the economics of operation in one or more regions. For example, an increase in summer capacity sales from the PNW to California, may change the PNW from a winter to a summer peaking system. Scheduling of PNW maintenance away from the summer peak may become desirable. An increase in winter firm energy sales from California to the PNW may change the economics of winter versus spring maintenance in California. A model with a fixed maintenance schedule could not easily represent the effect of maintenance scheduling on system economics and reliability.

An annual maintenance requirement for each unit or group of units is specified in the model input data set. On a monthly basis PMDAM schedules the fraction of the capacity of each group of generating units that is down for maintenance. This monthly maintenance fraction appears as a factor in Equation [2.28a].

Maintenance can be scheduled in one of two ways: fixed scheduling and economic scheduling. With fixed maintenance scheduling, the annual maintenance requirement is allocated to each month based on monthly fractions given in the input data set.

With economic scheduling, the fraction of maintenance in each month decreases in proportion to the net benefit of maintenance in each month. The net benefit of maintenance includes operating cost and reliability impacts of maintenance. The allowing equation expresses the maintenance fraction as a function of the net maintenance benefit and the maintenance slope:

[2.28b] Monthly Maintenance Fraction =

$$\text{Maintenance Slope} \times \text{Net Maintenance Benefit}$$

The maintenance slope in the above equation determines how sensitive the monthly maintenance fraction is to net maintenance benefit. If the slope is high then a small difference in net maintenance benefit in each month of the year will result in large differences in the amount of maintenance allocated to each month. With a very high slope, all of the annual maintenance requirement will be allocated to the month with the highest net maintenance benefit.

With a very low slope, maintenance will be allocated uniformly throughout the year.

Net maintenance benefit is determined by the following equation:

[2.28c] Net Maintenance Benefit =

$$\lambda_M - \lambda_r - \text{Monthly Net Operating Benefit}$$

In the above equation, $\lambda_M$, is the resource maintenance opportunity price. and $\lambda_r$ is the resource firm capacity opportunity price. All of the above terms are computed in \$/kW-yr units.

The maintenance opportunity price, $\lambda_M$, is adjusted by the PMDAM iterative algorithm until the total annual maintenance requirement is satisfied. This annual requirement is expressed by the following equation, which is the same as Equation [2.6]:

[2.28c]

$$\sum_{\text{months}} \frac{\text{monthly maintenance fraction } (\lambda_M)}{\text{number of months}} = \text{annual maintenance fraction}$$

The annual maintenance fraction is the fraction of the year the resource must be allocated to planned maintenance.

The monthly net operating benefit used in Equation [2.28c] is the sum of the hourly net operating benefit of all hours of the month weighted by the fraction of the resource that is not on forced outage and is committed for operation for the week. Mathematically, the monthly net operating benefit is computed as follows:

[2.28d]

$$\text{Monthly Net Operating Benefit} = \sum_{\text{hours of month}} \text{Net Operating Benefit(hour)} \times (1 - \text{Daily Forced Outage Fraction}) \times \text{Weekly Commitment Fraction} \times 8760 \text{ hours per year} \ / \ 1000 \text{ mills per \$}$$

The constants in Equation [2.28d] convert operating benefit from from mills per kWh to \$/kW-yr.

The calculation of the hourly net operating benefit is considered in Section 2.8.1.4.

Economic scheduling of maintenance will attempt to perform as much maintenance on a resource as possible in the lowest cost month for that resource. Too much maintenance in a single month will increase the resource's net operating benefit and capacity opportunity price in that month, so the resulting schedule will tend to be spread over several months to balance the maintenance benefits and costs. The maintenance slope input to the maintenance scheduling routine controls the sensitivity of the maintenance schedule to economics.

Firm energy considerations do not affect PMDAM maintenance scheduling because the scheduling (timing) of maintenance usually does not have a significant impact on the annual firm energy capability of a resource. Except for hydro resources, the annual firm energy capability of each resource is derated in the model by the annual maintenance requirement. For hydro resources maintenance scheduling is assumed to have no effect on annual firm energy capability because the annual stream flow is the principal limit on annual firm energy load carrying capability.

#### 2.8.1.3. Forced Outage

Forced outages of generating units are important in determining the ability of the system to meet peak loads. In modeling resource operation PMDAM randomly determines whether a unit is available on a given day based on the unit forced outage rate or probability. Alternatively, PMDAM will simply derate the capacity of each unit by the forced outage rate. Either way, the *daily forced outage fraction* appears as a term in the calculation of resource operating fraction in Equation [2.28a] A different probabilistic calculation is used to model system reliability for resource acquisition (see Section 2.12.2).

In representing random forced outages for resource operation, unit size in relation to the total capacity of a given group is considered. The total capacity of the group is divided by the average unit size to give the number of equivalent units. Each day, each equivalent unit is determined to be unavailable with probability equal to the forced outage rate. A random number generator is used to determine the state of each equivalent unit and the total number of units available for each day is computed. When the number of equivalent units in a group is large an approximation is used to save computer time. Additional special techniques are used to ensure that the random number sequence for all games does not change as additional units are acquired.

The calculations of unit availability are carried out for every calendar day of every year in the model horizon. The results are then converted as averages to the the time structure of the model.

The forced outage model assumes day to day outages are independent. For some model applications independence is not a good assumption because once a unit is forced out, repair may day more than one day. It is planned to represent repair time in the forced outage model.

#### 2.8.1.4. Net Operating Benefits

The net operating benefit of a generating resource is the opportunity price of the power produced by a generating resource less the operating marginal cost of the unit.

[2.29] Net Operating Benefit =

$$\lambda_e - \text{Operating Marginal Cost}$$

where

$\lambda_e$ is the hourly energy opportunity price.

The net operating benefit is computed in mills per kWh and converted to \$ per MW of available capacity. The net operating benefit is computed regardless of whether the resource is available so than the net operating benefits can be used to set commitment, maintenance and acquisition decisions. Net operating benefits are computed on a hourly basis and translated to daily, weekly, monthly and annual values.

### 2.8.2. Thermal Resource Operation

Thermal resources provide power while consuming a fuel. In this model, both fossil fuel and nuclear resources are modeled as thermal resources.

#### 2.8.2.1. Operating Limits

Each thermal generating resource in PMDAM is assigned a range of operation from a minimum to a maximum rate. The maximum operating limit is the daily available capacity computed as shown in Figure [2.5a].

The minimum operating limit is is a fixed fraction of the daily available capacity. In some cases the minimum operating fraction will be zero.

A unit once committed to operation during a week must not operate below the minimum operating level. Unit commitment in PMDAM is discussed in Section 2.8.2.4.

PMDAM does not restrict hour to hour changes in operation of thermal units except to the extent unit commitment and the minimum operation restrict hour to hour changes. If necessary, PMDAM can be modified to treat such restrictions or the costs of changing the power output level of a thermal resource.

### 2.8.2.2. Operating Marginal Cost

The hourly operating marginal cost of a thermal generating unit in mills/kWh is given by

[2.30] Operating Marginal Cost =
Fuel Marginal Cost +
Variable O&M Cost.

where

Fuel Marginal Cost is the incremental cost of the fuel used in mills per kWh of electricity produced, and

Variable O&M Cost is the incremental cost of variable nonfuel operating and maintenance costs.

Marginal costs exclude fixed fuel and fixed operating and maintenance costs. Distinguishing between fixed and variable fuel costs is often difficult and important. For example, the delivered price of natural gas includes the fixed and variable cost of natural gas transmission. Because of the complexity of natural gas price regulation and contracts it is often difficult to identify the fixed and variable components of natural gas costs.

Fuel marginal cost expressed in mills/kWh depends on the fuel price and the generating unit heat rate as follows:

[2.31] Fuel Marginal Cost =

$$\frac{\text{Heat Rate} \times \text{Variable Fuel Price}}{1000}$$

where

Heat Rate is the quantity of fuel used per unit of power generated and expressed in Btu/kWh,

Variable Fuel Price is the variable portion of the fuel price expressed in $/mmBtu, and

where the number 1000 is a conversion factor to adjust the units of measurement.

A typical heat rate for a thermal unit is about 10,000 Btu per kWh. Higher heat rates indicate less efficient units. For most units the heat rate changes with the output of the unit. PMDAM uses a fixed heat rate which should be a reasonable approximation given that individual units are aggregated into groups before operation is simulated.

Emissions marginal costs are also added to operating marginal costs as described in Section 2.13.

### 2.8.2.3. Dispatch

In each hour for each node (party in a given region) each generating resource is dispatched based on the hourly net operating benefit. The net operating benefit was defined as the difference between the hourly energy opportunity price and the variable operating cost. Figure 2.6. shows for each hour and node how the operating fraction for a group of generating resources increases as a function of the net operating benefit.

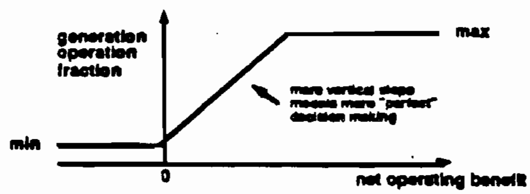



**Figure 2.6 - Generation Operation Fraction**

When the net operating benefit is zero or negative, the operating fraction is the minimum operating fraction. When the net operating benefit is very large the operating fraction is 1.0 In between a simple linear function is assumed. The slope of this function is given by the net operating benefit in mills per kWh required to just obtain full operation.

[2.32] Dispatch Slope =

$$\frac{(1 - \text{Minimum Operating Fraction})}{\text{Full Operation Net Benefit}}$$

The dispatch function is written as

[2.33] Generation Operation Fraction =
Minimum Operating Fraction +
Dispatch Slope × Net Operating Benefit

where

Minimum Operating Fraction ≤
Generation Operation Fraction ≤ 1.0

The generation operation fraction is permitted to range from the minimum operating fraction to 1.0. If the result of [2.33] is less than zero (net operating benefit is less than zero, then the generation operating fraction is set to the minimum operating fraction. If the result of [2.33] is greater than 1.0 (net operating benefit is greater than full operation net benefit, then the generation operation fraction is set to 1.0. A theoretical basis for this dispatch function is developed in Section 3 (see Equation [3.21] ).

The dispatch function used here can be interpreted in several ways. First, the dispatch function reflects the reality that in hours with high load and therefore high operating benefit, greater generation will be provided by the resource than in other hours with low load and low operating benefit.

Second, node resources with low variable operating cost will be operated more heavily in a given hour since the hourly energy opportunity price is the same for all resources at the node.

Third, resources with similar variable operating cost will be operated at similar levels. A resource group with a slightly lower variable operating cost will not be operated fully while the slightly higher cost resource group is operated at minimum levels. This result reflects the fact that variable operating cost for the group is not the only factor affecting dispatch. Variations in costs within a group of generating units means that the actual cost of dispatch tends to increase as the less expensive units or portions of units are dispatched first.

Fourth, other local reliability and transmission factors not represented explicitly in the model mean that resources are not operated in strict economic order as indicated by variable operating cost. The slope of the dispatch function can be adjusted so that some higher cost resources will be operated before lower costs groups of resources are fully dispatched. For example, it is often true that high cost gas turbine resources are operated more frequently than a purely cost oriented optimization of operation would indicate.

Fifth, complete information on operating costs, and hourly system marginal cost is not always available or fully used by operators, so that the slope of the dispatch function can be adjusted based on historical observations to better describe the actual behavior of the operators and utility operating system. A high dispatch slope indicates more perfect cost-minimizing decision making, whereas a lower slope makes the operating decisions much less sensitive to net operating benefit. A discussion of the behavioral or descriptive view of PMDAM versus the optimization view of PMDAM is covered in Section 3.

Figure 2.7 shows the equilibrium between the dispatch function and the derived demand for generation of this resource. The generation operation demand curve is the operation of the resource the rest of the model would use as a function of the net operating benefit of the resource. A high net operating benefit requires a high hourly energy opportunity price. A high hourly energy opportunity price means other generation and contract resources can substitute for generation by this resource. As a result the operation of this resource declines with the net operating benefit. The point where the demand curve and the dispatch function cross is the equilibrium operation fraction and net operation benefit for the resource.

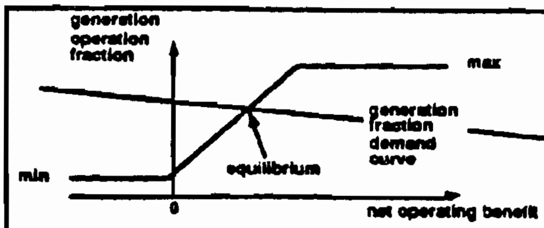



**Figure 2.7 - Generation Operation Fraction Equilibrium**

Figure 2.8 shows two dispatch functions with different slopes. A higher dispatch slope requires only a small net benefit for a large operation fraction. If the demand curve is relatively flat in comparison to the dispatch function, as shown in Figure 2.8, then the change in slope will have little effect on the operation fraction. Usually, many other generating and contract alternatives are available, the demand curve is flat, and the situation depicted in Figure 2.8 is typical.

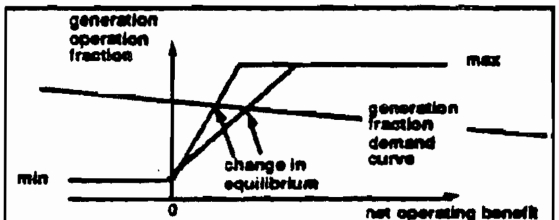



**Figure 2.8 - Effect of Dispatch Slope on Generation Equilibrium**

### 2.8.2.4. Commitment

Large thermal resources such as gas boilers, combined cycle and nuclear resources have limited operating flexibility. A large thermal resource, once committed to operation, must not operate below its minimum operating fraction.

The decision to commit a resource to operation for a period of time can be made on the basis of the net operating benefit of the resource over the commitment period. In PMDAM the commitment period is one week. In practice, the commitment period can vary. The simplifying restriction to a one week commitment period reduces the complexity of the model logic and appears to be a reasonable assumption for many studies. This assumption can be modified if necessary.

The hourly net operating benefit for a resource will vary over the hours of the week. In hours with high loads the net operating benefit will be high; in low load hours the net operating benefit will be low. If the weekly net operating benefit is greater than zero then it is advantageous to commit a resource to operation for the week.

### 2.8.3. Storage Resource Operation

(to be completed)

#### 2.8.3.1. Storage Capacity

#### 2.8.3.2. Storage Dispatch

#### 2.8.3.3. Stored Energy Prices

### 2.8.4. Hydro Resource Operation

Hydroelectric generation in the Pacific Northwest and British Columbia is the dominant source of electric power generation. BPA and other PNW agencies have many very sophisticated models of the hydroelectric system that are used for many different purposes. The hydroelectric component of the PMDAM model uses an economic representation of the hydro system that is quite different from that employed in other BPA hydro models.

The original purpose of PMDAM was to analyze long-term contract decisions between BPA and California parties. For this purpose a hydro model with sufficient detail to represent the energy, capacity and operating flexibility of the system as a whole was necessary. It was not necessary to represent the mainly individual storage reservoirs and generating projects on the PNW river systems.

A major consideration in designing the hydro model for PMDAM was the need to represent the economics of hydro system operation. Hydro models designed primarily for planning system operation under critical water conditions would not be adequate for this application. Models designed primarily to determine each party's rights and obligations in the PNW hydro system typically are not designed to simulate how the system would be operated under the different economic environments that PMDAM must investigate in the analysis of long-term power contracts and resource acquisitions.

#### 2.8.4.1. Aggregation of Hydro Projects

In PMDAM, each utility party is assumed to control a hydro resource with total generating capacity, reservoir capacity and inflow equal to total ownership or shares of ownership in individual generating projects. Thus, for the PNW, each of the five parties in the model control a single aggregate hydro resource. Linkages among these five PNW hydro resources result from dependence on the same inflow patterns and from coordinated operation of the hydro resources through the operating decisions made by the model subject to various physical and policy constraints.

#### 2.8.4.2. Hydro Inflows

Hydro inflows are not represented in PMDAM in physical units of water. Instead, hydro inflows are measured in equivalent units of electric energy the water flow would generate if run through the generating projects on the river system. Rates of inflow in PMDAM are distinguished on a monthly basis. Thus the measure of hydro inflow in PMDAM is average megawatts by month.

The hydro inflow in each month is a random variable in PMDAM. For each region the deviation in the monthly hydro inflow from average inflow for each party is assumed to be the same for each party in the region. This assumption reflects physical linkages and the high correlation between inflows to systems within a geographic region as a result of similar weather patterns.

Regional flows also are correlated with flows in other regions. For example, when British Columbia has higher than average flow conditions it is likely that the PNW also will have higher than average inflow conditions. A historical database on natural river flows at various key river locations is used to develop a multi-variate, log normal probability model that is used by PMDAM to generate correlated regional inflows for all five regions in the model.

The monthly inflows also are correlated with the previous months inflows. Typically, High May inflows are correlated with high June flows because both result from the same snow deposit. But, different weather patterns can affect the rate of melting of the snowpack so the relationship in month to month flows is not deterministic.

Based on the historical inflow data, The month to month correlation is built into the PMDAM hydro inflow model.

### 2.8.4.3. Hydro Storage Limits

Storage of water or its equivalent in hydro energy in reservoirs is limited by the physical capacity of the system and by operating policies. Operating policies may reflect power, flood control, fisheries, recreation, irrigation, navigation and other river system uses.

The PMDAM hydro model uses both upper and lower monthly limits on the energy content of each party's hydro system. These upper and lower storage content limits are expressed as a fraction of total physical energy storage capacity.

The physical energy storage capacity of the hydro systems in the five regions of the PMDAM model vary widely. In the Pacific Northwest, the reservoirs can store only about one-third of the average annual inflow. In the Pacific Southwest, the reservoirs can store about two years of average annual inflow.

The upper storage content limit is used in PMDAM to model flood control constraints. During the spring, storage capacity must be reserved to protect against extremely high inflows. The upper storage content limit is a function of the forecasted inflows.

The lower storage content limit is used in PMDAM to model operating restrictions for nonpower requirements. In the Pacific Northwest, lower energy content curves or limits are also used to maximize the regional firm load that can be carried by the hydro systems over a historical series of low water years. These and other curves help to determine the firm power rights and obligations of the owners of the hydro system. A party may draw on another party's storage in order to meet its firm loads.

In the Pacific Northwest, the hydro system may not be drafted by any party below the lower energy content curve except to meet total regional firm energy loads. Any draft from storage below the lower energy content limit must be proportional among the parties.

Lower energy storage content limits in PMDAM are hard limits that cannot be violated even to meet firm loads. Allocation of rights and obligations to firm power in PMDAM is modeled by assigning to each party its owned share of the firm power capability of the system. Operation of the combined hydro and thermal system to assure firm loads are met at least cost is modeled by the economic hydro dispatch decision rules described in Section 2.8.4.12.

### 2.8.4.4. Hydro Minimum Discharge Limit

Both a minimum instantaneous hydro discharge and a monthly minimum average hydro discharge are represented in the PMDAM model. Minimum flow requirements may be dictated by both power and non power needs. In the Pacific Northwest, minimum flow requirements needed to enhance fish transport and survival during the spring and early summer months is an important constraint on the efficient economic operation of the hydro system for power.

As with inflow and storage content, discharge in PMDAM is measured in units of equivalent electric energy.

### 2.8.4.5. Hydro Fish Bypass Requirement

Another means of supporting fish survival is to bypass or spill a portion of the flow that would normally pass through the turbines. The fraction of turbine generation discharge that bypasses the turbines is specified as in input to the model. The bypass fraction varies by hour of the day and month of the year, and is presently highest in the PNW during the night hours of the spring months.

### 2.8.4.6. Spill

Spill is hydro discharge above generation and fish bypass discharge Spill may be required for three reasons: to meet upper storage limits usually for flood control, to meet minimum discharge limits, and to meet hydro variability limits

During periods of very high inflow generation and bypass discharge may be insufficient to maintain the reservoir level below the upper storage limit. Spill is then used to increase the total discharge until the limit is met in the least cost way.

Minimum discharge spill is required when the generation and bypass discharge is less than the minimum discharge flow limit. High minimum flow requirements to support fish passage may force minimum discharge flow even when the off-peak market for generation is limited.

### 2.8.4.7. Total Discharge

The hourly total discharge is the sum of three operating decision variables given by

[2.34] Hydro Hourly Total Discharge =
Hydro Hourly Generation +
Hydro Hourly Bypass +
Hydro Hourly Spill

All four variables in the above equation are measured in average megawatts of equivalent water flow.

The calculation of hourly generation and spill are described in Sections 2.8.4.12 and 2.8.4.13, respectively. Bypass is a function of hourly generation.

### 2.8.4.8. Storage Content

End of month storage content is given by the following equation:

[2.35] Hydro Storage Content =
Hydro Storage Content ( month - 1 ) +
Hours per Month ×
Hydro Net Monthly Inflow

The hydro net monthly inflow is given by

[2.36] Hydro Net Monthly
Inflow = Hydro Monthly Inflow -
Hydro Monthly Total Discharge]

In [2.35] end of month hydro storage content for the previous month measured in hours, is increased by the hours per month times the net monthly inflow to give end of month hydro storage content for the current month.

In [2.36] net monthly inflow is the the average monthly inflow less the hydro monthly total discharge. All three variables in [2.36] are measured in average megawatts of equivalent electric generation.

### 2.8.4.9. Hydro Instantaneous Peaking Capacity

The maximum instantaneous generating capacity of a hydro system is the maximum rate at which the entire hydro system can generate power for a very short period, usually defined to be one hour. Instantaneous peaking capacity must be distinguished from sustained peaking capacity which is described in Section 2.8.4.10.

Instantaneous peaking capacity is principally a function of current storage content. High storage contents result in greater head at hydro projects. In modeling the operation of the hydro systems in PMDAM, instantaneous capacity versus content curves like that shown in Figure 2.9 are used.

**Figure 2.9 - Hydro Instantaneous Capacity vs. Stored Energy Content**

For planning purposes in calculating loss of load probability in PMDAM, the instantaneous capacity of the hydro system under storage levels consistent with a low or critical inflow condition is used as the dependable capacity of the hydro system. The instantaneous peaking capacity of the hydro system is an important term in the calculation of loss of load probability for both party and pool as described in Section 2.12.2.

### 2.8.4.10. Hydro Sustained Peaking Capacity

A hydroelectric generating system in contrast to a thermal generating system can respond very quickly to changes in output, but the hydro system is limited in its ability to vary its output widely over a period of a day or more on a sustained basis, day after day.

In the PNW, the hydro system is composed of a series of dams on a few river systems. Many of the dams are run-of-river projects with very little storage. These plants rely on releases from upstream reservoirs. Discharges from the upstream projects must be controlled so that flows arrive the downstream projects at a time when the generation at these downstream projects is most useful.

If the overall generation of the system varies widely over a period of a day in comparison to the average generation, then it may not be possible to control the flows between the dams sufficiently to meet the widely varying load. In addition the hydro system flexibility is constrained by flow restrictions at various points in the system.

For BPA, studies have been performed using detailed hydro models to determine the maximum sustained generation of the hydro system over given durations assuming various levels of average generation on the system. In planning the sale of power, BPA establishes a sustained peaking capacity for its system by reducing the instantaneous peaking capacity by an amount known as the sustained peaking reduction. In low flow months this reduction can exceed one-third of the instantaneous capability of the system.

Presently, for planning reliability purposes, the sustained peaking capacity reduction for BPA is taken as a deduction from the instantaneous peaking capacity of the BPA hydro system. The reduced peaking capacity of the BPA system then is used in calculating the BPA and PNW loss of load probabilities (see Section 2.12.2).

For operation under conditions different from planning, PMDAM uses a hydro variability limit to represent sustained peaking capability and limited hydro system flexibility in a more fundamental way.

### 2.8.4.11. Hydro Variability Limit

Hydro variability measures hydro system variability over the period of a day. It is computed as the ratio of the the standard deviation of hourly flow or discharge for the day to the average hourly flow for the day as follows.

**[2.36a]**
$$\text{daily variability} = \frac{\text{daily standard deviation}}{\text{daily average}}$$

where

daily standard deviation is the standard deviation of hourly discharge over the day, and

daily average is the average of hourly discharge over the day.

This ratio is not allowed to exceed a specified maximum value in simulating the operation of the hydro system.

### 2.8.4.12. Hydro Dispatch

The hourly dispatch of hydro generation in PMDAM uses the same general approach as for thermal units (see Equation 2.29) with one significant exception. The variable fuel cost of thermal generation is replaced by the opportunity costs associated with storage capacity, minimum discharge, and maximum variability constraints on the hydro system. Thus the operating marginal cost of a hydro resource for an hour is given by

[2.37]
$$\text{Operating Marginal Cost} = \text{Variable O\&M Cost} + \lambda_H - \lambda_D + \lambda_{vh}$$

where

$\lambda_H$ is the hydro energy opportunity price,

$\lambda_D$ is the hydro minimum discharge opportunity price, and

$\lambda_{vh}$ is the hydro variability hourly opportunity price.

Based the above equation and equations [2.29], [2.32] and [2.33] it is clear that hydro generation will be high when the hourly opportunity price of energy is high and the operating marginal cost in [2.37] is low.

The variable O&M cost for a hydro system is typically small and is provided as input data. The impact of the hydro opportunity prices on hydro generation dispatch is discussed in the remainder of Section 2.8.4.

### 2.8.4.13. Spill Operation

The hourly decision to spill hydro energy to meet upper storage or minimum discharge limits is determined by the net spill benefit given by

**[2.38]**
$$\text{Net Spill Benefit} = \lambda_D - \lambda_H - \lambda_{vh}$$

where

$\lambda_H$ is the hydro energy opportunity price,

$\lambda_D$ is the hydro minimum discharge opportunity price, and

$\lambda_{vh}$ is the hydro variability hourly opportunity price.

Figure 2.10. shows for each hour and node how the hourly spill for a hydro resource in PMDAM increases as a function of the net spill benefit.

**Figure 2.10 - Hourly Spill Operation**

When the net spill benefit is more negative than the minimum spill benefit, the spill is zero When the net operating benefit is above the minimum, the hourly spill increases in proportion to the spill slope which is an input to PMDAM. The equation for hourly spill is

[2.39]
$$\text{Hourly Spill} = \text{Spill Slope} \times \text{Net Spill Benefit}$$

when

Net Spill Benefit ≥ Minimum Spill Benefit

### 2.8.4.14. Hydro Energy Opportunity Prices

The hydro energy opportunity price, $\lambda_H$, reflects the lost opportunity to use hydro energy in a future hour if it is consumed in the current hour. $\lambda_H$ tends to be low when the overall supply of hydro energy is high and storage reservoirs are full. Full reservoirs imply that any energy not used cannot be stored until a time when hydro energy is more valuable. A low hydro energy opportunity price in [2.37] encourages hydro generation in that hour.

The hydro energy opportunity price in PMDAM varies by the month of the year. The hydro energy opportunity price is derived from the opportunity price on hydro storage capacity and a forecast of the next month's hydro opportunity cost as follows:

$$[2.40] \quad \lambda_H = \lambda_H(\text{month} + 1) - \lambda_{su} + \lambda_{sl}$$

where

$\lambda_H$ is the hydro energy opportunity price for the current month,

$\lambda_H(\text{month} + 1)$ is the forecast hydro energy opportunity price for the next month,

$\lambda_{su}$ is the upper hydro stored energy opportunity price at the end of the current month,

$\lambda_{sl}$ is the lower hydro stored energy opportunity price at the end of the current month.

The forecast of next month's hydro energy opportunity price is just next month's hydro opportunity price, if certainty in inflows and other variables is assumed. Under uncertainty, the forecast of next month's hydro energy opportunity price is different. Forecasting of hydro opportunity prices is considered in Section 2.8.4.20.

### 2.8.4.15. Hydro Stored Energy Opportunity Prices

Both upper and lower hydro stored energy opportunity prices are defined in the model.

#### Upper Stored Energy Opportunity Price

The upper stored energy opportunity price, $\lambda_{su}$, is associated with the constraint that the ending storage contents not exceed the upper storage content limit as described in Section 2.8.4.3. On a given iteration of the model, if the storage contents at the end of the current month exceed the upper limit, then the upper stored energy opportunity price will be increased by the PMDAM algorithm until the end contents equal the upper limit.

The upper stored energy opportunity price, $\lambda_{su}$, is is a negative term in equation [2.40] which determines, $\lambda_H$, the hydro energy opportunity price. For example, if the upper stored energy opportunity price, $\lambda_{su}$, at the end of this month is 3 mills per kWh, and if next month's hydro energy opportunity price is 20 mills per kWh, then this month's hydro energy opportunity price will be 17 mills.

Continuing with the above example, if, at 17 mills per kWh enough hydro energy is dispatched so that the month end stored energy is less than the upper limit, then the PMDAM algorithm on successive iterations will adjust the upper stored energy opportunity price, $\lambda_{su}$, downward from 3 mills per kWh. The downward adjustment in $\lambda_{su}$ will increase $\lambda_H$ causing less hydro generation during the month. The downward adjustment in $\lambda_{su}$ (upward adjustment in $\lambda_H$) will continue until the the upper stored energy limit is just reached or the upper stored energy opportunity price, $\lambda_{su}$, is zero and the stored energy is less than the upper limit at the end of the month.

In high flow situations it is possible that the upper stored energy opportunity price, $\lambda_{su}$, may have to be increased to the point where $\lambda_H$, the hydro energy opportunity price for the current month becomes a negative number. In this case the net spill benefit as computed in Equation [2.38] will likely be positive. A positive net spill benefit will result in spill, thus increasing the flow and decreasing the stored energy at the end of the month.

#### Lower Stored Energy Opportunity Price

The lower stored energy opportunity price, $\lambda_{sl}$, is associated with the constraint that the ending storage contents not be less than the lower storage content limit as described in Section 2.8.4.3. On a given iteration of the model, if the storage contents at the end of the current month are less than the lower limit, then the lower stored energy opportunity price will be increased by the PMDAM algorithm until the end contents equal the lower limit.

The lower stored energy opportunity price, $\lambda_{sl}$, is is a positive term in equation [2.40] which determines, $\lambda_H$, the hydro energy opportunity price. For example, if the lower stored energy opportunity price, $\lambda_{sl}$, at the end of this month is 5 mills per kWh, and if next month's hydro energy opportunity price is 30 mills per kWh, then this month's hydro energy opportunity price will be 35 mills,.

Continuing with the above example, if, at 35 mills per kWh enough hydro energy is dispatched so that the month end stored energy is greater than the lower limit, then the PMDAM algorithm on successive iterations will adjust the lower stored energy opportunity price, $\lambda_{sl}$, downward from 5 mills per kWh. The downward adjustment in $\lambda_{sl}$ will decrease $\lambda_H$ causing more hydro generation during the month. The downward adjustment in $\lambda_{sl}$ and $\lambda_H$ will continue until the the lower stored energy limit is just reached or the lower stored energy opportunity price, $\lambda_{su}$, is zero and the stored energy is greater than the lower limit at the end of the month.

### 2.8.4.16. Hydro Minimum Discharge Opportunity Prices

The hydro minimum discharge opportunity price, $\lambda_D$, is associated with the constraint on minimum monthly discharge flow as described in Section 2.8.4.4. $\lambda_D$ is a negative term in Equation [2.37]. A high $\lambda_D$ encourages dispatch of hydro generation and higher flow. A high $\lambda_D$ also increases net spill benefit and will encourage spill to increase flows, if necessary.

If on a given iteration of the model, the monthly average flow is below the minimum discharge constraint, then the PMDAM algorithm increases the minimum discharge opportunity price, $\lambda_D$. Increasing $\lambda_D$ will decrease the operating marginal cost of a hydro resource in Equation [2.37] thereby increasing the net operating benefit and increasing the discharge from the hydro system in most hours. $\lambda_D$ is increased until the minimum discharge constraint is met. If the final solution discharge exceeds the minimum discharge then $\lambda_D$ will be zero.

In low flow situations it is possible that the minimum discharge opportunity price, $\lambda_D$, may have to be increased to the point the net spill benefit as computed in Equation [2.38] is positive. A positive net spill benefit will result in spill, thus increasing the flow in the direction of meeting the minimum discharge limit.

### 2.8.4.17. Hydro Hourly Variability Opportunity Prices

In Equation [2.37] the hydro hourly variability opportunity price, $\lambda_{vh}$, reflects the limited flexibility of the hydro system to vary its output over the hours of the the day. When the hydro system is being stressed, in high load hours $\lambda_{vh}$ will be a positive number adding to $\lambda_H$ in Equation [2.37]. In low load hours $\lambda_{vh}$ will be a negative number.

$\lambda_{vh}$ is derived from the hydro daily variability opportunity based on the following equation:

$$[2.41]\quad \lambda_{vh} = \lambda_{vd}\ \frac{\partial \text{ daily variablity}}{\partial \text{ hydro hourly discharge}_h}$$

where

$\lambda_{vd}$ is the hydro daily variability opportunity price, and

$$\text{daily variability} = \frac{\text{daily standard deviation}}{\text{daily average}}$$

daily standard deviation is the standard deviation of hourly discharge over the day.

daily average is the average of hourly discharge over the day.

The partial derivative term in Equation [2.41] is positive in peak hours and negative in off-peak hours. Thus $\lambda_{vh}$ is negative in off-peak hours when $\lambda_{vd}$ is non-zero.

In off-peak hours $\lambda_{vh}$ as a negative number will tend to encourage off-peak spill and discourage on-peak spill, thus reducing hydro daily variability.

### 2.8.4.18. Hydro Daily Variability Opportunity Prices

The hydro daily variability opportunity price, $\lambda_{vd}$, is associated with the daily variability limit described in Section 2.8.4.9. If this limit is exceeded the PMDAM algorithm will increase $\lambda_{vd}$ until the limit is met. If the daily variability at the solution is less than the limit then $\lambda_{vd}$ must be zero at the solution.

Increasing $\lambda_{vd}$, increases $\lambda_{vh}$ in on-peak hours and decreases $\lambda_{vh}$ in off-peak hours. These changes in opportunity prices will discourage on-peak hydro generation and encourage off-peak generation or spill thus reducing the variability of the flows.

### 2.8.4.19. Equilibrium Hydro Operation

The operation of the PMDAM hydro model cannot be fully understood in isolation from the rest of the power system. Hydro energy competes with thermal energy to satisfy native and contract loads. The hourly hydro energy opportunity price, $\lambda_H$, in Equation [2.40] will reach a balance or equilibrium with the thermal operating costs through Equation [2.33]. In achieving this equilibrium, the PMDAM algorithm will have employed the available hydro inflows in the most economic way subject to the storage, minimum discharge and daily variability constraints.

Economic operation of the hydro system entails the dispatch of the combined hydro thermal system and contracting among parties to minimize costs to customers. The PMDAM algorithm accomplishes this economic dispatch. coordinating all dispatches via the hourly energy opportunity prices $\lambda_e$, for all nodes and for all hours.

### 2.8.4.20. Forecasting Hydro Energy Opportunity Prices

Equation [2.40] requires a forecast of next month's hydro energy opportunity price $\lambda_H$. Under certainty, next month's $\lambda_H$ can be computed by estimating the $\lambda_H$ for the last month in the model horizon, and then calculating $\lambda_H$ for each previous month in reverse order of time. The structure of the PMDAM algorithm easily permits this order of calculation.

Under uncertainty, the forecast of next month's $\lambda_H$ may be different from the actual $\lambda_H$ for the next month. Mathematically, the forecast of next month's $\lambda_H$ should be the conditional expected value of next month's $\lambda_H$ given the outcomes of all uncertain variables for the current month. This conditional expected value can only be approximated in PMDAM. An exact calculation of all of the conditional expected values is impossible for a problem the size of that solved in PMDAM.

Two methods of computing conditional expectations of next month's $\lambda_H$ are provided in PMDAM: an end-of-year expectation function method and a monthly expectation adjustment method.

**End-of-Year Expectation Function Method**

The end-of-year conditional expectation method assumes certain knowledge of next month's $\lambda_H$ within the calendar year, but no knowledge of next month's $\lambda_H$ at the end of the calendar year. In the PNW, a preliminary estimate of the snowpack and future inflows for the next calendar year is made in early January. If this forecast were completely accurate (it is not ) then only an estimate of the $\lambda_H$ forecast at the end of the calendar year would be necessary. $\lambda_H$ for all earlier months in the calendar year could be computed in reverse order of time assuming certainty within the calendar year.

One way to estimate the end-of-year $\lambda_H$ expectation is to assume it is zero, and use the lower energy limit described in Section 2.8.4.3. to assure sufficient stored energy is carried over to the next year. By this method, the equilibrium value of the lower stored energy opportunity price, $\lambda_{sl}$, would adjust until the end-of-year stored energy equals the end-of-year lower energy limit.

The problem with the above end-of-year method is that in high flow years hydro energy may displace very low cost thermal resources in order to reduce the end-of-year stored energy contents to the lower energy limit. This is because the method has assumed additional energy above the lower limit has zero value.

The end-of year expectation method can be improved by using a function to assign a value to end-of-year stored energy above the lower energy limit. Figure 2.11 illustrates the type of function used to determine this end-of-year forecast.

Figure 2.11

If, at the end of the year, the reservoir is at the upper storage limit, then additional hydro energy will have little value because it may be spilled in the following month. If, at the end of the year, the reservoir is at the lower storage limit, then additional hydro energy will have high value because it is likely to displace high variable cost gas turbine generation in the following year.

Depending on the inflow and other uncertain variables for the current year, the model will find an end-of-year storage content between the upper and lower limit. The upper and lower limits can be adjusted in the model until the end-of-calendar-year expected hydro energy opportunity price, $\lambda_H$, equals the beginning-of-year average $\lambda_H$ across all games with similar values of other uncertain variables. A run with certainty on all variables except hydro flows can be used for this adjustment in the end-of-year expectation function parameters.

**Monthly Expectation Adjustment Method**

The monthly expectation adjustment method is more sophisticated than the end-of-year method. The monthly expectation adjustment method adjusts next month's actual $\lambda_H$ based on sensitivity information and the differences between the conditional expectations of next month's uncertain variables and the actual outcomes of these variables. The adjustment equation is as follows:

$$[2.42]\ \ EV[\lambda_H] = \lambda_H$$
$$+ \text{inflow sens} \times (EV[\text{inflow}] - \text{inflow})$$
$$+ \text{load sens} \times (EV[\text{load}] - \text{load})$$

where

EV[] indicates the one month conditional expectation of a variable.

inflow sens is the estimated change in $\lambda_H$ per unit change in monthly inflow. and

load sens is the estimated change in $\lambda_H$ per unit change in monthly native load.

Any number of uncertain variables can be included in Equation [2.42]. Also variables from other parties can be included. For example,BC Hydro's inflow may have a significant effect on PNW hydro opportunity prices.

The expected value of next month's hydro inflow for the PNW, for example, is a n output of the hydro inflow uncertainty model as described in Section 2.??. The actual hydro inflow for next month is available within PMDAM.

The inflow sensitivity can be estimated from the output of previous PMDAM model runs, by plotting $\lambda_H$ versus inflow for various months and parties. Eventually, it should be possible to compute and update the sensitivity estimates required by [2.42] as the PMDAM iterations proceed.

The monthly expectation adjustment model has been implemented within PMDAM but has not yet been fully tested.

## 2.8.4.21. Summary of Hydro Model Interactions

Figure 2.12 summarizes the major interactions among the opportunity prices and quantities in the PMDAM hydro model. The bold ellipses highlight the four opportunity price variables in the hydro model. The hydro hourly generation is a function of all four opportunity prices. as defined by Equations [2.35], [2.29] and [2.33]. High hourly system or minimum flow $\lambda$ increase hourly generation while high hydro energy $\lambda$ decreases hourly generation. High daily variability $\lambda$ increases peak hourly variability $\lambda$ and decreases peak hourly generation. High daily variability $\lambda$ decreases off-peak hourly variability $\lambda$ and increases off-peak hourly generation.

The upper and lower hydro energy storage capacity opportunity prices, $\lambda_{su}$ and $\lambda_{sl}$, are not shown but are used in the calculation of the hydro energy opportunity price $\lambda_H$ as defined by Equation [2.40]. The daily variability opportunity price, $\lambda_{vd}$ also is not shown but is used in the calculation of the hourly variability opportunity price, $\lambda_{vh}$ as defined by Equation [2.37]

In Figure 2.12 hourly generation feeds into hourly total discharge at the right. Hourly generation and the bypass fraction, a model input, determine bypass flow. Bypass flow is added also added into hourly total discharge.

Spill is a function of three of the opportunity prices as defined by Equations [2.36] and [2.37]. Spill is added into hourly total discharge.

The hourly discharge is averaged over the month and compared to the monthly minimum discharge requirement to determine the monthly minimum discharge opportunity price, $\lambda_D$.

Hourly total discharge over a day determines daily variability of discharge. Daily discharge is compared to the daily variability limit to adjust the daily and hourly variability opportunity price (see Equation [2.37]) The daily variability opportunity price is not shown in the figure.

The end of month stored energy content is determined by the hourly total discharges for the month and by the monthly inflow as represented in Equation [2.35] and [2.36].

Finally the hydro energy opportunity price $\lambda_H$ is determined by the stored energy content of the system. the storage capacity of the system, and the upper and lower storage limits as fractions of the storage capacity. Not shown the in figure are the upper and lower storage capacity opportunity prices, $\lambda_{su}$ and $\lambda_{sl}$ used to compute $\lambda_H$.

A major influence not indicated in Figure 2.12 is the influence of hourly hydro generation on hourly energy opportunity price, $\lambda_e$. Increases in hydro hourly generation cause decreases in the hourly energy opportunity price because of the displacement of less costly other resources and contracts by the additional hydro generation.

### 2.8.5. Nondispatchable Resource Operation

Nondispatchable resources represent conservation, wind/solar and co-generation resources in the PMDAM model. For these resources, the generation operation fraction, as computed in [2.33] for dispatchable resources, is specified as a model input.

#### 2.8.5.1. Conservation

For nondispatchable conservation resources the equivalent generation operation fraction ( actually a reduction in native load) is specified as a fraction of the resource capacity. This fraction varies by month and hour of the day. No fuel is consumed by this resource.

Dispatchable conservation such as load management program is not currently modeled but can be easily implemented in PMDAM.

#### 2.8.5.2. Wind/Solar

For nondispatchable wind and solar resources the generation operation fraction is specified as a fraction of the resource capacity. This fraction varies by month and hour of the day. No fuel is consumed by this resource.

#### 2.8.5.3. Co-Generation

For nondispatchable co-generation resources

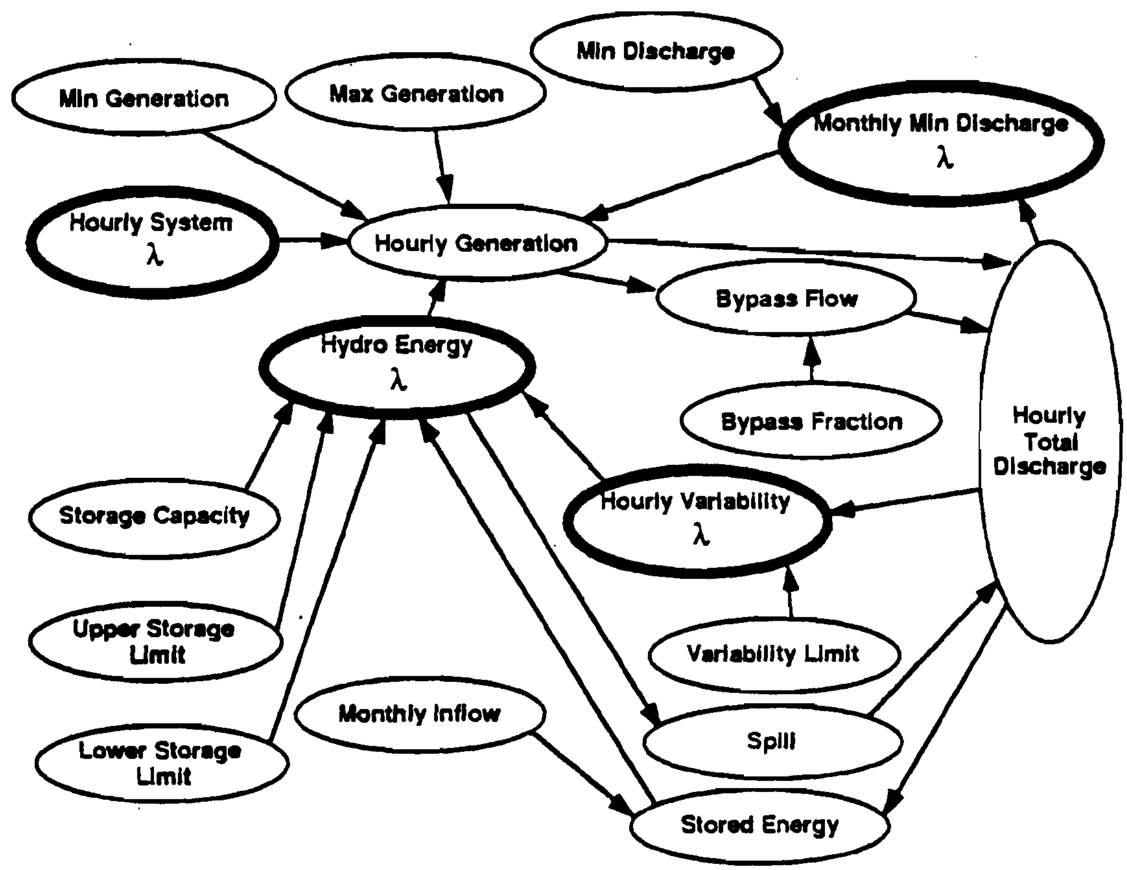



**Figure 2.12 - PMDAM Hydro Model Influence Diagram**

the generation operation fraction is set to 1.0 in all hours, except when the unit is on maintenance or forced outage. Fuel is consumed by this resource. A low heat rate is used to account for the fuel that is displaced by the steam produced by the co-generation resource.

### 2.8.6. Acquisition of Resources

Generating and conservation resources may be acquired by each party in the PMDAM model. Resource acquisitions may be specified as a model input or the least-cost acquisitions may be determined by the iterative algorithm of the model.

### 2.8.6.1. Resource Supply Curves

The capital cost and supply of each new generating resource is specified by a resource supply curve. Figure 2.13 shows a hypothetical resource supply curve.

The vertical axis in Figure 2.13 is the overnight per unit capital cost of the resource, expressed in $/kW of nameplate capacity. Nameplate capacity is assumed to be the maximum generating capacity of the resource under standard operating conditions, assuming no reductions in capacity for forced outage and maintenance. Overnight capital cost excludes interest and escalation during the construction period and is expressed in currency units for a common base year assumed for the model.

Figure 2.13 - Resource Supply Curve

The horizontal axis in Figure 2.13 is the cumulative nameplate capacity of the resource added beyond that already installed or committed at the beginning of the model time horizon.

As Figure 2.13 indicates, the per unit capital cost or price of the resource increases with the cumulative resource commitments. This increase usually represents increased costs as the most attractive plant sites and fuel sources are committed first.

Figure 2.14 shows in a common graph, four resource supply curves used in the model. The capital costs are expressed in 1989 dollars.

The PNW combined cycle generating resource curve in Figure 2.14 is flat, indicating that the capital price or per unit cost of this resource is assumed not to increase with cumulative commitments.

The PNW nuclear resource supply curve in Figure 2.14 shows about 2500 megawatts of nameplate generating capacity available at about $1200 per kW or less. This resource consists of two partially completed nuclear plants, WNP1&3, now in preservation status. One of the two plants is estimated to cost slightly less than the other, as indicated by the small increase in capital price at about 1250 megawatts of cumulative capacity. No nuclear resource additions beyond 2500 megawatts will be considered by the model, because the PNW nuclear supply curve in Figure 2.14 assigns a very high capital price to any cumulative additions above 2500 megawatts.

The PNW conservation supply curve in Figure 2.14 shows about 2500 megawatts of nameplate generating capacity available at about $6000 per kW or less. About 2000 megawatts is available at less than $2000 per kW. The energy associated with this conservation (a model input) is about 55 per cent of the capacity, so 2000 megawatts of conservation capacity provides 1100 average megawatts of energy conservation. The conservation resource consists of a series of conservation measures of increasing cost.

The hydro electric supply curve for British Columbia is also shown in Figure 2.14 The figure shows about 3700 megawatts of nameplate generating capacity available at about $2500 per kW or less. The cost gradually increases from about 1000 megawatts to 3700 megawatts. The data in this curve come from very preliminary estimates based on published BC Hydro data that is somewhat out of date. Better estimates are in development.

Each of the resource supply curves in the model is specified on a regional basis. Parties within the region are assumed to compete to develop the resources available at any given price.

### 2.8.6.2. Resource Cost Escalation

For each resource type by region, a real escalation rate is defined as input data. The escalation rate may vary over time. Real escalation is combined with a general inflation rate to determine the capital price of the resource in nominal currency. Real escalation and inflation are multiplied by any increase in resource capital price as a result of cumulative commitments as applied to the resource supply curve.

Resource cost escalation during the construction period of the resource is computed assuming all of the construction expenses are incurred uniformly over the construction period.

### 2.8.6.3. Resource Construction Interest

Interest on construction capital costs during the construction period of a resource is computed as a multiplier on the escalated capital price of a resource. Construction expenses are assumed to be incurred uniformly over the construction period.

### 2.8.6.4. Resource Economic Rent

The cumulative demand or acquisition of a generating resource must not exceed the supply of the resource as determined by the supply curve for the resource. To enforce this constraint while determining the least-cost acquisition of resources requires the definition of the resource capital opportunity price.

The constraint on resource acquisition supply and demand is given by

[2.43]

$$\text{Cumulative Resource Additions}_y \leq \text{Resource Supply} (\lambda_{qy})$$

where

$\lambda_{qy}$ is the opportunity price on the resource supply demand constraint in year y for a given resource

**(to be completed)**

### 2.8.6.5. Maximum Acquisition Rate

The maximum acquisition rate for a resource specifies the upper limit on the nameplate megawatts that a party can acquire in a given year. This limit is normally used to limit the acquisition of conservation resources to reflect limitations on the ability to develop programs and staff to carry out conservation programs and because of the time it takes to obtain customer participation in a conservation program. These limits are applied directly to the acquisition decision and do not result in the specification of an additional opportunity price associated with this constraint.

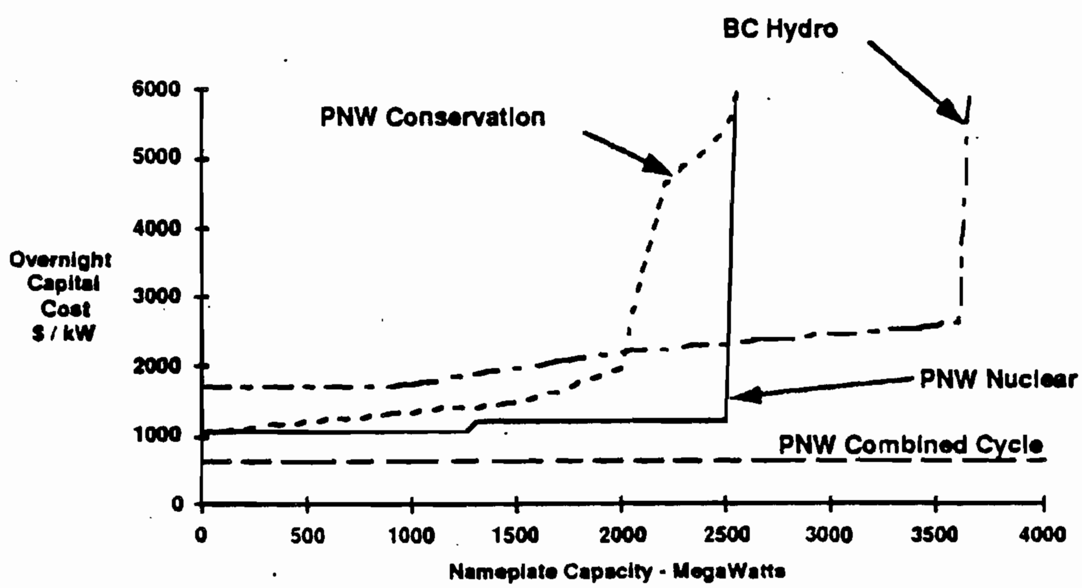



**Figure 2.14 - Example Resource Supply Curves**

### 2.8.6.6. Net Acquisition Benefit

Resources are acquired in PMDAM whent eh levelized net acquisition benefit is greater than zero. The annual net acquisition benefit of a resource is given by

[2.46a] Net Acquisition Benefit =
Firm Capacity Benefit +
Energy Firmness Benefit +
Operating Benefit -
Variable Operating Cost -
Fixed Operating Cost -
Capital Cost -
Environmental Cost

Thelevelized net acquisition benefit is computed from the annual net acquisition benefits in each year the resource will be available.

Thelevelized net acquisition benefit can aslo be computed froim the levleized valuse of each term in [2.46a] as follows:

[2.46b] L(Net Acquisition Benefit) =
L(Firm Capacity Benefit) +
L(Energy Firmness Benefit) +
L(Operating Benefit) -
L(Variable Operating Cost) -
L(Fixed Operating Cost) -
L(Capital Cost) -
L(Environmental Cost)

(to be completed

**Firm Capacity Benefit**

**Energy Firmness Benefit**

**Operating Benefit**

**Variable Operating Cost**

**Fixed Operating Cost**

**Capital Cost**

**Environmental Cost**

(to be completed)

### 2.8.6.7. Acquisition Decision

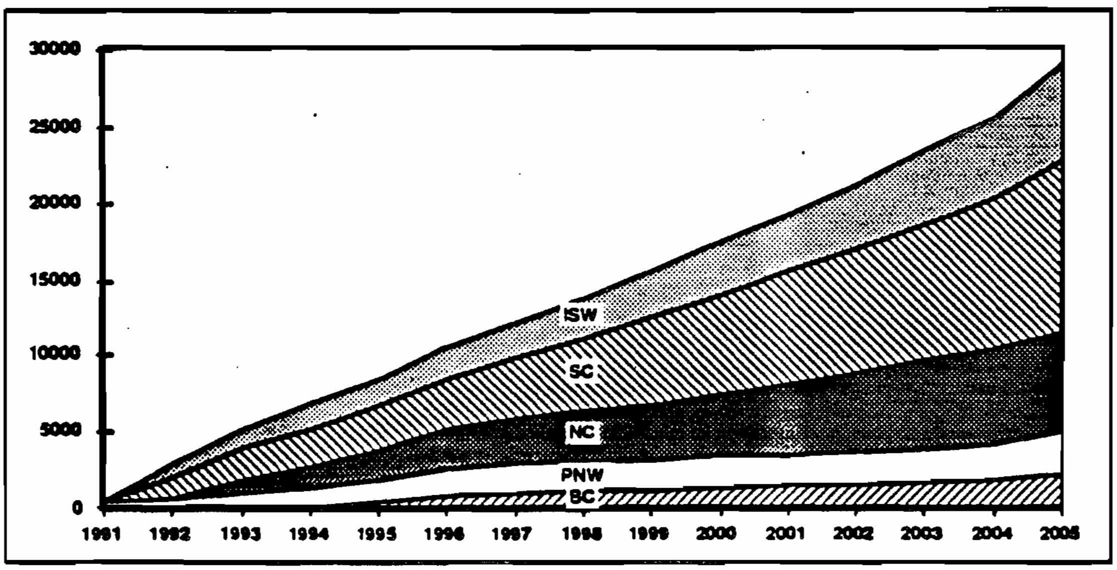
(to be completed)

### 2.8.6.8. Lead Time and Uncertainty

(to be completed)

### 2.8.6.9. Conditional Forecasts

Conditional forecasts of the uncertain opportunity price variables that feed into the acquisition decision making process are necessary to reflect the current information available at the time each acquisition decision is made. The opportunity prices are uncertain (vary by game) because the load, fuel price, hydro




(Nameplate Capacity - MegaWatts)

**Figure 2.15 - West Coast Resource Additions by Regions**

inflows and plant availability variables that affect the opportunity prices are uncertain. Since acquisition decisions in the model are made over time, the conditional forecasts of opportunity prices used for these decisions should change over time.

Acquisition decisions are based on the conditional expected value of the opportunity price variables that feed into the acquisition decisions. This conditional expected value is in a sense a conditional forecast. Each year this conditional expected value is computed for each game using a technique that employs conditional weights on the opportunity prices for many games. The calculation of conditional expected opportunity prices for acquisition decision making is discussed in Section 3.6.

Operating decisions are usually made in PMDAM assuming certainty in the opportunity price variables that affect the decisions. For example, each hourly system opportunity price is assumed known when making each hourly operating decision for a game. A conditional forecasting technique for hydro storage operating decisions in the face of hydro inflow uncertainty is under development.

(to be completed)

## 2.9. Transmission

The overall economics and energy losses associated with power transmission between the major points of delivery on the West Coast are modeled in PMDAM. Opportunity prices on transmission operation and firm transmission capacity are used to allocate the use of transmission in contract operation and acquisition.

### 2.9.1. Transmission Network

The overall transmission network currently modeled in PMDAM was described in Figure 2.2. A portion of the transmission network, the alternating current (AC) transmission system from the Pacific Northwest to Northern California is shown in Figure 2.16. In this figure the ownership shares of the AC system at full rated capacity are shown. The ownership shares change at the California Oregon border (COB).

### 2.9.2. Transmission Links

Each transmission system element in Figure 2.16 is called an *owner's transmission link* in PMDAM. An owner's transmission link describes a single owner's share of a

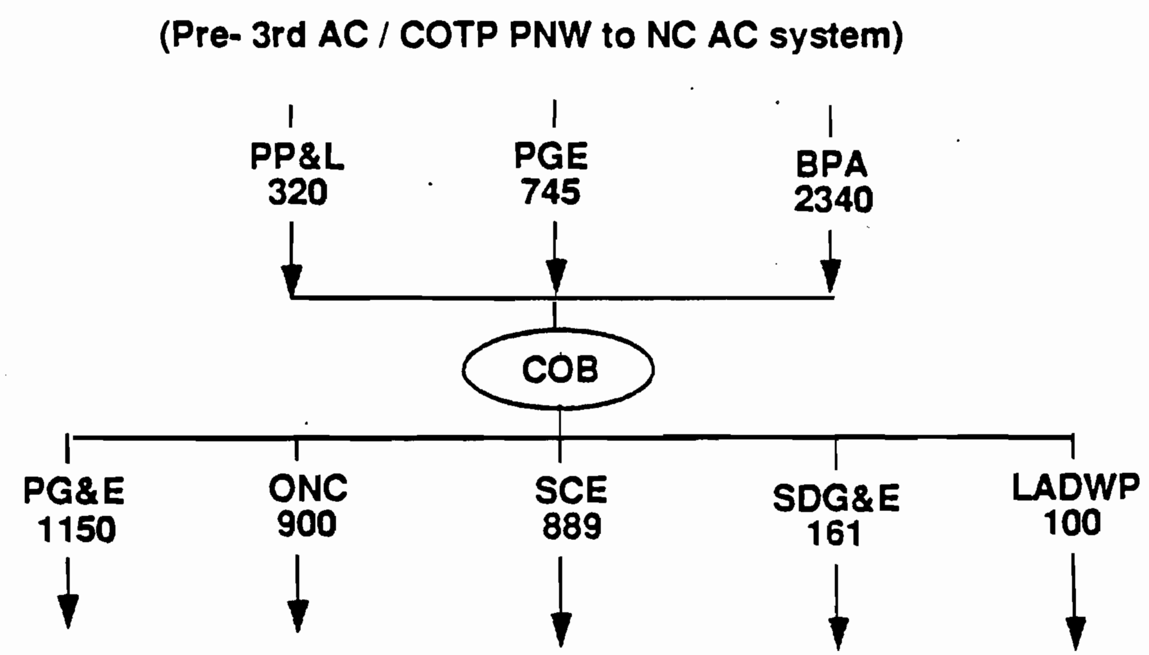



**Figure 2.16 - Example Ownership of Transmission**

*transmission link.* A transmission link is the combined capability of all owner's transmission links between two points of delivery.

For modeling purposes a transmission link is given direction in PMDAM. Each transmission link has a *forward* and a *reverse* direction.

For each direction a *from* point and a *to* point is defined. Also a forward and a reverse direction is defined for each transmission link. Because of line loss it is necessary to characterize the capacity of the link in each direction at a specific point.

PMDAM uses the convention of defining link capacity at the from point on the link in each direction. The capacity at the to point can be computed by multiplying the from point capacity by the loss fraction at full load. Figure 2.17 illustrates the transmission link direction and end point definitions as used in PMDAM.

The capacity of a transmission link in the forward direction need not equal the capacity of the line in the reverse direction. Differences in the forward and the reverse capacity of a transmission link may result from differences in reliability criteria applied in setting the maximum transmission capability. Also use of transmission to satisfy local needs may restrict the use of a transmission link as modeled in PMDAM.

**Figure 2.17 - Transmission Link Conventions**

### 2.9.3. Transmission Losses

Transmission losses are important because of the great distances power must travel between points of delivery within the Western region modeled by PMDAM. Transmission losses are a nonlinear function of the load placed on the line: that is the transmission efficiency or loss per unit of energy transmitted is much higher at full load on the transmission link than at low load.

Transmission loss is computed from the transmission efficiency of a transmission link. Transmission efficiency as a function of transmission load at the *from* point on the link is given by:

[2.60] Transmission Loss Fraction =
Zero Load Transmission Loss Fraction+
Transmission Load ×
Transmission Loss Slope

[2.61] Transmission Loss Slope =
(Max Load Transmission Loss Fraction -
Zero Load Transmission Loss Fraction) /
Max Transmission Load

[2.62] Transmission Loss =
Transmission Load ×
Transmission Loss Fraction

[2.63] Marginal Transmission Loss =
Transmission Load ×
Marginal Transmission Loss Fraction

[2.64]
Marginal Transmission Loss Fraction =
Zero Load Transmission Loss Fraction+
Transmission Load × 2.0 ×
Transmission Loss Slope

Typical values for minimum and maximum load transmission efficiency for transmission links from British Columbia to Southern California are shown in columns 1 and 2 of Table 2.3a Also shown in column 3 of the table is the marginal transmission efficiency at full load. At the bottom of the table the cumulative efficiency are shown for transmission from British Columbia to Southern California. These cumulative efficiencies clearly demonstrate the importance of modeling transmission loss as a function of load.

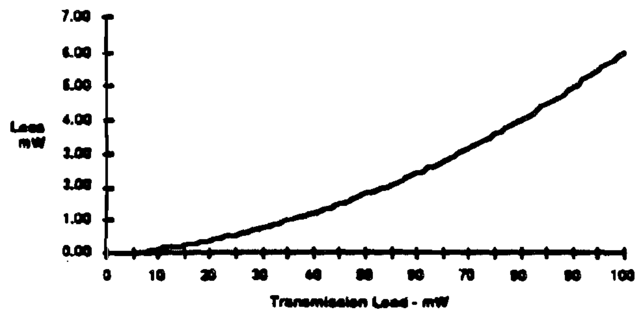



**Figure 2.18 - Transmission Loss vs. Load for 100 mw Line**

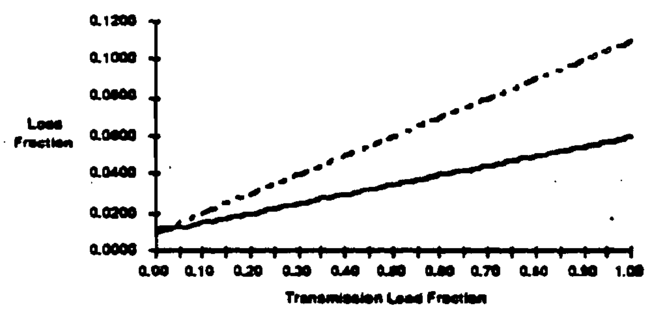



**Figure 2.17 - Transmission Loss Fraction vs. Load Fraction**

## 2.9.4 Transmission Operation

The decisions to allocate electric energy for transmission between points of delivery on transmission lines are determined by the acquisition and operating decision rules for the contracts among the parties. These contracts include both firm and non-firm contracts. The operating decision rules for the contracts take into account transmission losses as described in the previous section 2.9.2. and limits on the total amount and ownership of transmission capacity.

(to be completed)

## 2.9.5. Transmission Acquisition

Acquisition of transmission facilities in PMDAM currently is modeled only by an input schedule of new transmission facilities. PMDAM does not currently acquire transmission facilities based on least-cost

| Point of Delivery | | Average Energy Loss Fraction | Average Energy Loss Fraction | Marginal Energy Loss Fraction |
|---|---|---|---|---|
| From | To | At Zero Load | At Max Load | At Max Load |
| BC | PNW | 0.0045 | 0.0546 | 0.1047 |
| PNW | COB | 0.0095 | 0.0638 | 0.1181 |
| COB | NC | 0.0149 | 0.0644 | 0.1139 |
| NC | SC | 0.0046 | 0.0556 | 0.1066 |
| BC | SC | 0.0331 | 0.2180 | 0.3749 |

**Table 2.3a Example- Transmission Loss Fractions**

economics.

The PMDAM opportunity prices for transmission capacity and operation provide information on the benefits of additional transmission facilities. These estimates can be compared with the costs of additional transmission to judge whether the input schedule of transmission facility additions is economic.

Transmission supply curves and the equations to allow PMDAM to acquire transmission can be added to PMDAM using the same general approach as for generating resource acquisition when the need arises.

(to be completed)

### 2.9.6. Transmission Paths

(to be completed)

#### 2.9.6.1. Path Definitions

(to be completed)

#### 2.9.6.2. Metapath Definitions

A metapath in PMDAM is the set of all transmission paths that a contract may use in transmitting power between two utilities.

## 2.10. Contracts

The original purpose of PMDAM was to evaluate power contracts between BPA and other major West Coast utilities. As a result of this original focus, the model has considerable detail in the area of contracts among utilities.

Both existing and potential new contracts among parties are represented in the model. Existing Contracts are described in Section 2.10.1. To simplify the choices in acquiring new contracts within the model a series of generic contracts is used. Generic contracts are described in Section 2.10.2.

All contracts in the model are implemented using one or more basic contract links as described in Section 2.10.3. These basic contract links are essentially simplified contracts. By combining these basic contract links, very complex contracts can be represented in PMDAM.

Contract operation is described in Section 2.10.4. Contract operation is similar to resource operation, except for the need to carefully identify which party controls the operation of each of the basic contract links that form a contract. Economy energy contract links are jointly controlled by both parties to the contract.

Contract acquisition is described in Section 2.10.5. Contract acquisition is similar to resource acquisition except that two parties must agree on the quantity and price of the acquisition.

### 2.10.1. Existing Contracts

About 150 existing contracts between West Coast utilities are modeled. Tables 2.? and 2.? illustrate the input data for two of these existing contracts.

It is important to include existing contracts in the model because the existing contracts reflect commitments among the parties that may be quite different from the contract commitments that would result if the parties negotiated new contracts based on current economics.

### 2.10.2. Generic Contracts

Generic contracts in PMDAM represent the spectrum of alternative future contracts among parties in the same way that generic resources represent the alternative future resource acquisitions by parties.

The following five types of generic contracts are currently used in PMDAM:

100 % Load Factor Firm Power
50 % Load Factor Firm Power
24 Hour Capacity Return
Option Firm Energy without Capacity
Economy Energy

The first two firm power contracts in the above list provide both firm capacity and firm energy buyer rights and seller obligations.

### 2.10.3. Basic Contract Links

Each of the existing and generic contracts in the model is implemented using one or more basic contract links. The basic contract links currently defined in the model are as follows:

Economy Energy Link
Firm Power Link
Demand Power Link
Exchange Firm Energy Link
Option Firm Energy Link
Capacity Delivery Link
Capacity Return Link

Table 2.A shows the basic contract links used for each generic contract and for two of the existing contracts.

The basic contract links are described in Sections 2.10.3.1 to 2.10.3.7 which follow. For each contract link, the important issue is which party or parties control the contract decisions.

### 2.10.3.1. Economy Energy Link

(to be completed)

### 2.10.3.2. Firm Power Link

(to be completed)

### 2.10.3.3. Demand Power Link

(to be completed)

| | To Party | From Party | Joint |
|---|---|---|---|
| Economy Energy Link | | | ✔ |
| Firm Power Link | ✔ | | |
| Demand Power Link | ✔ | | |
| Exchange Firm Energy Link | ✔ | | |
| Option Firm Energy Link | ✔ | | |
| Capacity Delivery Link | ✔ | | |
| Capacity Return Link | | ✔ | |

### 2.10.3.4. Exchange Firm Energy Link

(to be completed)

### 2.10.3.5. Option Firm Energy Link

(to be completed)

### 2.10.3.6. Capacity Delivery Link

(to be completed)

### 2.10.3.7. Capacity Return Link

(to be completed)

| | Firm Energy | Firm Capacity | Take or Pay Energy |
|---|---|---|---|
| Economy Energy Link | | | |
| Firm Power Link | ✔ | ✔ | ✔ |
| Demand Power Link | ✔ | ✔ | |
| Exchange Firm Energy Link | ✔ | | ✔ |
| Option Firm Energy Link | ✔ | | |
| Capacity Delivery Link | | ✔ | |
| Capacity Return Link | ✔ | | |

| | Economy Energy Link | Firm Power Link | Demand Power Link | Exchange Firm Energy Link | Option Firm Energy Link | Capacity Delivery Link | Capacity Return Link |
|---|---|---|---|---|---|---|---|
| 100 % Load Factor Firm Power | | ✔ | | | | | |
| 50 % Load Factor Firm Power | | ✔ | | | | | |
| 24 Hour Capacity Return | | | | | | ✔ | ✔ |
| Option Firm Energy without Capacity | | | | | ✔ | | |
| Economy Energy | ✔ | | | | | | |
| BPA to SCE Capacity Energy Exchange | | ✔ | | ✔ | ✔ | ✔ | ✔ |
| ISW to SCE Purchase | | | ✔ | | | | |

### 2.10.4. Contract Operation

(to be completed)

### 2.10.5. Contract Acquisition

(to be completed)

#### 2.10.5.1. Net Acquisition Benefit

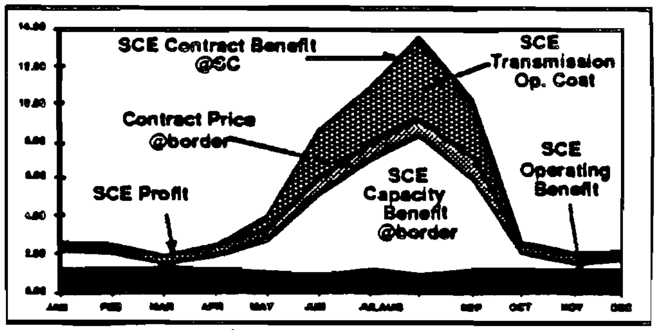
#### 2.10.5.2. Acquisition Decision

#### 2.10.5.3. Contract Acquisition Price

**Firm Capacity Benefit**

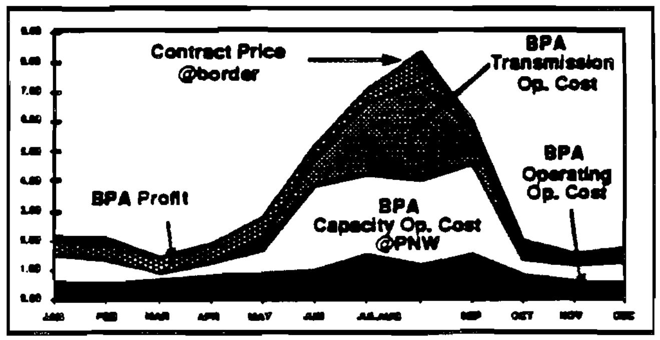
**Energy Firmness Benefit**

**Operating Benefit**




(levelized 1993 $/kw-month over 13 years)

**Figure 2.17 - Capacity Contract Benefits to Buyer (SCE)**




(levelized 1993 $/kw-month over 13 years)

**Figure 2.18 - Capacity Contract Opportunity Costs to Seller (BPA)**

## 2.11. Financial

(to be completed)

### 2.11.1. Financial Conventions

(to be completed)

#### 2.11.1.1. Timing of Financial Flows

(to be completed)

#### 2.11.1.2. Nominal and Real Currency

(to be completed)

### 2.11.2. Financial Costs

(to be completed)

### 2.11.3. Rates

(to be completed)

## 2.12. Reliability

(to be completed)

### 2.12.1. Firm Energy

(to be completed)

#### 2.12.1.1. Party Firm Load/Resource Balance

(to be completed)

#### 2.12.1.2. Energy Firmness Opportunity Price

(to be completed)

### 2.12.2. Firm Capacity

(to be completed)

#### 2.12.2.1. Party Loss of Load Probability

(to be completed)

#### 2.12.2.2. Pool Loss of Load Probability

(to be completed)

#### 2.12.2.3. Firm Capacity Opportunity Price

## 2.13. Environmental

Air Emission currently modeled are

Carbon ( carbon dioxide)
Nitrogen Oxides
Sulfur Oxides
Suspended Particulates

### 2.13.1. Emissions Quantities

Emission quantities are based on the quantity of fuel used by each generating resource and an emissions rate factor.

[2.??] Emission Quantity =
Generation ×
Resource Heat Rate ×
Fuel Heat Content ×
Resource Emissions Rate$_i$

where
Resource Emission Rate$_i$ is the quantity of the $i^{th}$ type of emissions ( i.e. tons of Carbon ) per unit of fuel consumed by a given generating resource.

### 2.13.2. Emissions Taxes

Emissions taxes are charges paid by utilities to government agencies based on the emissions of a generating facility. Emissions taxes for

[2.??] Resource Emissions Tax Rate =

$$\sum_{i=1}^{MAXEMS} [ \text{Emission Tax Rate}_i \times \text{Emission Rate}_i \times \text{Resource Heat Rate} ]$$

### 2.13.3. Emissions Opportunity Prices

(to be completed)

### 2.13.4. Emissions Constraints

(to be completed)

# 3. Solution of the Model

## 3.1. Alternative Views of the Model

The Power Market Decision Analysis Model is described in this section from four different views. The first, economic equilibrium view provides the best description of PMDAM. The other three views enhance understanding of the model. The four views of the model are as follows:

1. **Economic Equilibrium View**
   an economic theory description of the model as one that determines prices at which supply and demand are balanced.
2. **System of Simultaneous Equations View**
   a mathematical description of the model as a large system of behavioral and physical equations.
3. **Optimization View**
   a mathematical description of the model wherein the decision making objective is to minimize costs.
4. **Simulation View**
   a description of the model as one that tries to mimic actual power markets, utility investment, and operating decisions.

The economic equilibrium view best describes the methodology of the PMDAM model. Taking this view, the model is described as a set of parties each representing one or more electric utilities. Each utility is assumed to have the objective of minimizing the cost of serving its native load customers. Each party operates and acquires those generating and contract resources, and serves those contract loads that achieve this least-cost objective. Contracts among parties are negotiated so that both parties receive benefit at a mutually agreed price and quantity.

The economic equilibrium view of the model also can be expressed as a system of simultaneous equations. It is these equations that are actually coded in the computer implementation of the model. Inspection of these equations provides some useful insights into the model.

The economic equilibrium view can be seen as an optimization problem for each party that is interconnected to the optimization problems of the other parties. No overall objective function is assumed. However, in studying market efficiency or developing coordinated resource plans, it is useful to consider how the solution of the model would differ when an overall objective function and optimal solution for the systems of all parties is assumed. This perspective is provided by the optimization view.

The economic equilibrium view, properly applied, attempts to describe actual market decisions rather than optimal decisions. In a sense the model is a simulation of the actual market. Viewing the model as a simulation of the market allows us to better compare actual versus model decision making.

## 3.2. Economic Equilibrium View

The description of PMDAM as an economic equilibrium model begins by describing the network of parties that characterize the participants in the market.

For each party an optimization problem is defined. This optimization problem is specified by an objective function, a set of decision variables, and a set of constraints.

The optimization problem for each party is connected to the optimization problems of the other parties. The quantities of power commodities such as energy and capacity received by the buying party must equal the quantities delivered to the selling party at a common point of delivery. The contracting parties must also agree on the prices of the power commodities.

The solution to each party's optimization problem is formulated using the Lagrange multiplier method. This solution method provides a rigorous and intuitive way to describe the solution of the problem. The solution method also leads to the computational algorithm used by PMDAM.

Contract decisions in the model are of two types: unilateral and bilateral. Unilateral decisions such as the operating level of a firm power contract are made by one of the parties (the buyer in this case) and accepted by the other. Bilateral contract decisions such as the quantity of hourly economy energy transferred between two parties or acquisition of long-term firm power contracts are made jointly by the buying and selling parties. Both parties must agree on the price and quantity of bilateral contract transactions within the framework of the solution to each party's optimization problem.

The solution of PMDAM is an economic equilibrium solution among the parties. Each party buys from or sells power to other parties at a price that balances supply and demand. This equilibrium solution is described by economic supply and demand curves. Examination of this equilibrium condition also gives insight into using the model to represent cases where market power is exercised and the transactions may not be least-cost from an over societal perspective.

### 3.2.1. Network of Parties

A network of parties, each party representing one or more electric utilities, describes the participants in the market modeled by PMDAM. Figure 3.1 illustrates this network for the case of three parties. Each party is assumed to serve the loads of its native customers using a set of generating resource alternatives and contracts with other parties. In Figure 3.1, the symbol $l$ is used to denote native load, the symbol x denotes generation decision variables, and the symbol q denotes contract decision variables. The symbol $\pi$ denotes the prices at which contract transactions are carried out between parties.

Decisions to operate and acquire generating and contract resources and to serve native and contract loads are made by each party to minimize the cost of serving its own native load.

To simplify the theoretical development of the methodology in this section, a party is assumed to operate and own resources and serve native loads in only one region. A party may contract with other parties in the same or other regions.

### 3.2.2. Party Optimization Problem

An optimization problem in this context is a decision problem wherein an objective function is stated and the decision variables are set to values that maximize or minimize the objective function subject to a set of constraints. Therefore, the model is described here in terms of an objective function, a set of decision variables and a set of constraints.

#### 3.2.2.1. Objective Function

The objective function for each party is to minimize the present value of net costs of operation and expansion of its system to serve the native loads of its customers at least-cost.

Costs are defined here to be costs to the native customers of the utilities in the market. The profits of the utility are assumed to be determined by regulation and are included in this cost to native customers. Revenues from sales to

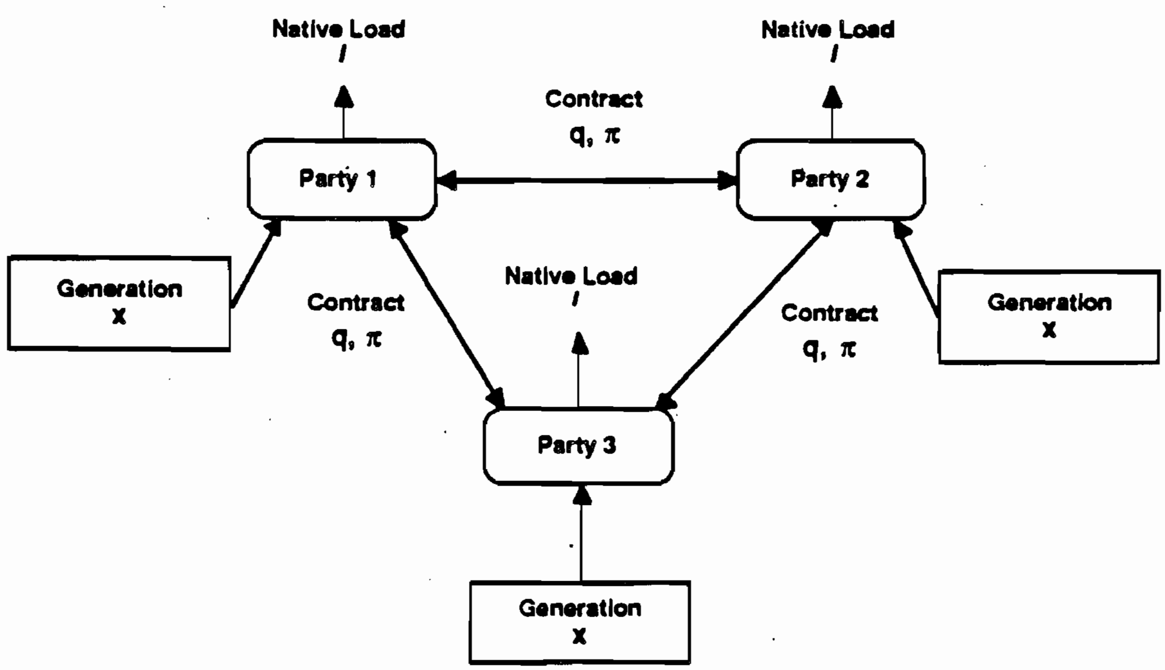



Figure 3.1 - Network of Parties

other utilities are considered as deductions from net costs. Revenues from native load customers are not considered in calculation of net costs since these revenues will recover the net costs.

The model does not currently compute the customer benefits of electricity consumption.

Costs are defined here to include all financial and environmental costs. As described in Section 2.13 environmental impacts may be translated into equivalent financial costs for purposes of analysis.

Costs over time are accumulated and discounted at a discount rate that represents time preference on costs of power paid by customers. The model assumes costs within the year are accumulated without interest or discounting.

The discount rate used to compute the present value of costs over each year of the model horizon can vary by party. This discount rate can also be different from the interest rate used to finance capital expenditures. The discount rate is used to compute a party discount factor, that translates a cost in a given year into a present value of cost in a base or reference year. The base year is usually the first year of the model or the actual year in which the analysis is carried out.

The role of uncertainty in the development of the methodology is considered in Section 3.6. The development of the methodology in the next several sections assumes certainty.

Mathematically, the objective function for each party is written as

$$[3.1]\quad \text{Minimize } C_p(x,q,l,\pi) \quad \text{over all } x \in X_p,\ q \in Q_p,\ l \in L_p$$

where

- $C_p()$ is the present value of net cost to the native load customers of party p,
- x is a vector of resource decision variables for all parties
- q is a vector of contract decision variables for all parties,
- l (small L)is a vector of native load decision variables for all parties,
- $\pi$ is a vector of contract price variables for all parties,
- $X_p$ is the set of all possible values of the resource decision variables for party p, and
- $Q_p$ is the set of all possible values of the contract decision variables for party p, and
- $L_p$ is the set of all possible values of the native load decision variables for party p.

The minimization in [3.1] is performed only on the decision variables that apply to party p. The decision vectors x, q and l contain decision variables for resources and contracts for all parties, but the sets $X_p$, $Q_p$ and $L_p$ restrict the minimization to those variables controlled by party p. This rather general notation permits decision variables controlled by one party to affect the costs of another party. Typically, there will be many elements of x, q and l that will have no direct influence on $C_p()$.

$X_p$, $Q_p$ and $L_p$ are subsets of the set of all decision variables in the model which are denoted by

- X is the set of all possible values of the resource decision variables for all parties
- Q is the set of all possible values of the contract decision variables for all parties
- L is the native load decision variables for all parties

The terms x, q and l are vectors of variables subscripted by resource, contract, or native load and time. There are usually several decision variables for each resource, contract or native load. These decision variables relate to various aspects of acquisition and operation as described in Section 3.2.2.2.

The native load decision variable l controls the fraction of native load served. In the case of firm native loads, such loads would only be curtailed in outage situations where energy is unavailable at a price less than the outage price for the resource.

The present value of net cost is written as

$$[3.2]\quad C_p(x,q,l,\pi) = \sum_{y=0}^{Y} c_{py}(x,q,l,\pi)\ \beta_{py}$$

where

y is the year index,

Y is the number of years in the model horizon,

$c_{py}(x,q,l,\pi))$ is the annual net cost of power to native load customers of party p in year y, and

$\beta_{py}$ is the party discount factor from year y to the base year

The annual net cost is written as the sum of several components as follows:

$$[3.3]\quad c_{py}(x,q,l,\pi) = c_{py}(x) + c_{py}(l) + c_{py}(q,\pi) + c_{py}$$

where

$c_{py}(x)$ is the cost of party resource operation and acquisition in year y,

$c_{py}(l)$ is the *outage* cost of party native load operation in year y,

$c_{py}(q,\pi)$ is the net cost of party contract operation and acquisition in year y (revenues from contracts are considered negative costs in this item), and

$c_{py}$ is other net costs such as sunk cost, and overhead costs not affected by resource and contract decision variables (fixed revenues from sources other than power contracts and native loads are negative costs in this item)

### 3.2.2.2. Decision Variables

The resource related decision variables, x, for the model are the following:

1. the hourly operating fraction for each group of generating units,
2. the hourly spill for each group of hydro generating units,
3. the weekly commitment fraction for each group of generating units,
4. the monthly maintenance fraction for each group of generating units, and
5. the nameplate capacity of each group of generating units acquired in each year,

The contract related decision variables, q, for the model are the following:

1. the quantity of power transferred in each model hour for each contract and along a particular transmission path between a pair of parties , and
2. the quantity of each long term contract between a pair of parties.

The contract decision variables may be set jointly with both parties having to agree on the decision, or unilaterally by one party with the other party accepting the decision. An example of the joint decision is the decision by two parties to contract for non-firm, economy energy in a single hour. An example of the unilateral decision is the operating decision for a firm power contract where the buyer alone decides when to take delivery of energy.

The only native load related decision variable, in the model is the following:

the fraction of each native load served in each model hour.

The native load decision variable is used to determine the fraction of firm energy loads served in outage situations and the fraction of native non-firm loads that should be served based on the utility party's obligation to its customer's.

### 3.2.2.3. Constraints

Constraints specify the physical relationships among variables in the model. For example, in each hour the supply of energy must equal the demand for energy. It is also possible to use constraints to represent policy considerations such as a limit on emissions.

The basic physical constraints for the model are the following:

1. Hourly Load/Resource Balance
2. Hourly Transmission Capacity
3. Annual Maintenance Requirement
4. Daily Pumped Energy Storage
5. Monthly Hydro Energy Storage
6. Monthly Hydro Minimum Discharge
7. Daily Hydro Discharge Variability
8. Annual, Monthly, Weekly and Daily Contract Energy Limits
9. Monthly Capacity/Peak Demand Balance (LOLP)
10. Annual Firm Energy/Firm Load Balance
11. Monthly Firm Transmission Capacity.

The set of all constraints in the model can be written as

$$[3.4]\quad R(x,q,l) \le 0$$

where

$R(x,q,l)$ is a set of equations specifying the relationships among the decision variables,

The symbol **R** is used to represent the set of constraints because each constraint can be interpreted as defining a balance of a scarce resource such as energy, capacity, or maintenance (a scarce resource is not to be confused with a generating resource that may supply a scarce resource such as energy).

Both linear and nonlinear constraints are permitted in **R**. It will sometime be necessary to distinguish between the equality and inequality constraints in [3.4]. In such cases the constraints **R** will be written as

$$[3.5]\quad R_e(x,q,l) = 0$$
$$R_i\,(x,q,l) \le 0$$

where

$R_e$ denotes the equality constraints, and

$R_i$ denotes the inequality constraints.

### 3.2.3. Lagrangian Formulation of the Solution

For each party, an optimization problem has been defined. The optimization problem for each party is interconnected by common elements of the contract decision vector q, and the contract prices $\pi$. The solution of the overall, interconnected problem is developed in two steps. First, in Section 3.2.2 the form of the solution to the party optimization problem is developed assuming contract prices, $\pi$, for both the buyer and seller are given. Then in section 3.2.4 the contact prices are computed so that the contract decision vectors q, imply that the quantity of power purchased by the buyer equal the quantity sold by the seller and the price paid by the buyer equals the price received by the seller..

The solution to the party optimization problem requires the definition of opportunity prices (also called Lagrange multipliers.) The solution is then formulated as a set of equations in the decision variables and opportunity prices. These equations can be given the interpretation of supply and demand equations in a economic equilibrium framework.

The optimization problem for each party is restated as follows:

$$[3.6] \quad \text{Minimize } C_p(x,q,l,\pi) \quad \text{over all } x \in X_p,\ q \in Q_p,\ l \in L_p \quad \text{subject to } R(x,q,l) \leq 0$$

It should be noted that the contract decision variables for a party may be set freely in the above problem without regard to the other party's contract decisions. Also the contract price, $\pi$, is not a decision variable in the above optimization problem. The additional requirements that buyers and seller agree on contract decision variables and prices will be imposed later in this development.

The solution to a general optimization problem with nonlinear objective function and nonlinear constraints is given by the Lagrange Multiplier Method [1,2].

The Lagrange Multiplier Method begins by defining a new function called the Lagrangian function as

$$[3.7] \quad L_p(x,q,l,\pi,\lambda'_p) = C_p(x,q,l,\pi) - \lambda'_p\, R(x,q,l))$$

where

$\lambda'_p$ is vector of Lagrange multipliers for party p.

Lagrange multipliers are also called opportunity prices in this document.

The prime symbol for the Lagrange multiplier $\lambda'_p$ indicates its units are present value dollars per unit of the constraint. Another Lagrange multiplier used in this document is written without the prime symbol and is given by

$$[3.8] \quad \lambda_p = \frac{\lambda'_p}{\beta_{py}}$$

The price vector $\lambda_p$ is in dollar units of year y. Typically PMDAM uses Lagrange multipliers or opportunity prices measured in dollar units for each year. However, in developing the theory of PMDAM and in using opportunity prices for acquisition decisions, the present value measure of opportunity price is essential.

The Lagrangian function is formed by defining a vector of Lagrange multipliers, one for each constraint equation in **R** and then subtracting the inner product of $\lambda'_p$ and $R(x,q,l\ )$ from $C(x,q,l,\pi)$. This inner product is given by

$$[3.9] \quad \lambda'_p\, R(x,q,l)) = \sum_{n=1}^{N} \lambda'_{pn}\, r_n(x,q,l\ )$$

where

n is the index over the constraints in **R**,

N is the number of constraints in **R**,

$\lambda'_{pn}$ is the party Lagrange multiplier, also called the opportunity price for constraint n, and

$r_n$ is the $n^{th}$ constraint.

The theory of the Lagrange Multiplier Method defines the necessary conditions for an optimal solution to [3.6] as two sets of equations. The first set of optimality equations is derived from the partial derivative of the Lagrangian function with respect to the decision variables. The second set of optimality equations is derived from the partial derivative of the Lagrangian function with respect to the Lagrange multipliers $\lambda'_{pn}$.

The partial derivative of the Lagrangian with respect to the party decision variables provides the first set of optimality equations for a party. The party decision variables, a subset of all the decision variables in the model, are indicated by $x_p$, $q_p$ and $l_p$ in the equations below. Optimality equations are produced from the partials with respect to each of the decision variables as follows:

$$[3.10]\quad \frac{\partial C_p(x,q,l,\pi)}{\partial x_p} - \lambda'_p \frac{\partial R(x,q,l)}{\partial x_p} = 0$$

$$[3.11]\quad \frac{\partial C_p(x,q,l,\pi)}{\partial q_p} - \lambda'_p \frac{\partial R(x,q,l)}{\partial q_p} = 0$$

$$[3.12]\quad \frac{\partial C_p(x,q,l,\pi)}{\partial l_p} - \lambda'_p \frac{\partial R(x,q,l)}{\partial l_p} = 0$$

The second set of equations is directly related to the constraint equations. This set of equations is the partial derivative of the Lagrangian function with respect to the Lagrange multipliers. For the equality constraint equations, the solution simply requires the constraint equations be satisfied as follows:

$$[3.13]\quad R_e(x,q,l) = 0$$

For inequality constraint equations, the Lagrange Multiplier Method restricts the sign of the Lagrange multiplier to the nonnegative range if the constraint $R_e(x,q,l)$ is less than or equal to zero. The sign of the Lagrange multiplier is restricted to the nonpositive range if the constraint $R_e(x,q,l)$ is greater than or equal to zero.

By convention in PMDAM, all of the inequality constraints are written as less than or equal constraints so that the corresponding Lagrange multipliers will be nonnegative. A greater than or equal to zero constraint is converted to a less than or equal constraint by reversing the sign of every term in the equation.

If an inequality constraint is satisfied as a strict inequality then the Lagrange multiplier must be zero. These equations can be written as follows:

$$[3.14]\quad \lambda'_p R_i(x,q,l) = 0 \text{ and } \lambda'_p \geq 0$$

Clearly, many constraints and Lagrange multipliers will not be relevant to a single party's solution. Many derivatives in [3.10] through [3.12] will be zero. It would have been possible to have not defined constraints and Lagrange multipliers for such cases, but this more general approach will simplify the description of other aspects of the methodology.

### 3.2.4. Iterative Solution Algorithm

Equations [3.10] through [3.14] specify the solution to the party optimization problem [3.6] as a system of equations. Since the solutions to the party problems will interact through common decision variables, the solution to the overall market problem is given by a large system of equations, composed of all of the party equations.

This system of a equations can be solved by an iterative algorithm. There are several possible variations on this basic algorithm, but the basic algorithm is as follows:

**Basic Iterative Algorithm**

1. Estimate the vector $\lambda'_p$ for all parties,
2. Compute tentative contract prices $\pi$ and tentative quantities for all **x**, **q** and **l** from Equations [3.10], [3.11] and [3.12]
3. Compute the error in satisfying the constraint equations using

   $e = R(x,q,l)$ )
3. If $e = 0$ then STOP,
4. Otherwise, set $\lambda' = \lambda' - \alpha e$ for all $\lambda'$ ( for $\lambda'$ associated with inequality constraints ,keep $\lambda' \geq 0$ ) and return to Step 2.

Each of the four steps in this basic algorithm is discussed next.

#### 3.2.4.1. Estimating Opportunity Prices

The initial estimate of the opportunity prices affects the number of iterations to reach a solution. Because there are so many individual opportunity prices to estimate, it is necessary to compute the estimate based on a rough idea of the critical factors that will determine the final values of the opportunity prices.

#### 3.2.4.2. Computing Tentative Decisions

At first inspection it may seem difficult to solve Equations [3.10] through [3.12] for the decision variables. However, when PMDAM's specific functional forms for C() and R() are used and when the derivatives are taken the result in PMDAM is usually a simple linear equation that is easily solved.

The development of all equations for computing the decision variables in this step of the algorithm is beyond the scope of this document. A resource operating example is presented here to illustrate the development. In Section 3.2.5 the equations for computing bilateral economy energy contract operation and price are developed.

**Solving for the Decision Variable**

The example concerns the operation of a thermal generating resource in hour h. The decision variable $x_{hk}$ is the hourly operating fraction for a resource k owned by party p. The hourly operating fraction is restricted to the range $x_{mink}$ to 1.0 where $x_{mink}$ is the minimum operating fraction. This restriction on the range of the decision variable is one of the limits imposed by the set **X**.

The only term in C() that depends directly on $x_{hk}$ is the hourly operating cost $c_{hk}(x_{hk})$. Applying the calculus chain rule of differentiation to Equations [3.2] and [3.3], the first term of Equation [3.10] is

$$[3.15] \quad \backslash F(\partial C_p(x,q,l,\pi),\partial x_{hk}) = \beta_{py} \frac{\partial c_{hk}(x_{hk})}{\partial x_{hk}}$$

where

$\beta_{py}$ is the party discount factor from year y to the base year as defined in Equation [3.2].

In PMDAM, the function $c_{hk}(x_{hk})$ for a thermal resource is the operating marginal cost multiplied by the level of operation of the resource. The operating marginal cost is assumed to increase linearly as a function of the operating fraction. This means the resource operating cost is quadratic in the operating fraction, $x_{hk}$, as given by

$$[3.16] \quad c_{hk}(x_{hk}) = v_{hk}\ x_{mink}\ c_{wk} + \left(v_{hk} + \frac{1}{2s}(x_{hk} - x_{mink})\right)(x_{hk} - x_{mink})\ c_{wk}$$

where

$v_{hk}$ is the variable operating price of a thermal resource **k** in mills/kWh (see Equation [2.16]),

$x_{hk}$ is the hourly operating fraction of resource k,

$x_{mink}$ is the minimum hourly operating fraction of resource k,

$c_{wk}$ is the capacity of resource k in mW committed for the week to operation and not on maintenance or forced outage,

$\frac{1}{2s}$ is the linear rate of increase in the variable operating price of resource k as a function of the hourly operating fraction.

Replacing [3.16] in [3.15] gives the following partial derivative as the first term of [3.10].

$$[3.17] \quad \frac{\partial C_p(x,q,l,\pi)}{\partial x_{hk}} = \beta_{py}\ c_{wk}\left(v_{hk} + \frac{1}{s}(x_{hk} - x_{mink})\right)$$

The second term of Equation [3.10] involves the constraint **R**(x,q,l). The decision variable $x_{hk}$ is involved only in the hourly load resource balance constraint and any emissions constraints. Ignoring the emissions constraints for now, the hourly load resource balance constraint is

$$[3.18] \quad \sum_k x_{hk}\ c_{wk} - \text{sales}(q,\pi) + \text{purchases}(q,\pi) - \text{native loads}(l) = 0$$

where the summation in [3.18] is over all resources employed by the party in meeting loads. Thus,

$$[3.19] \quad \frac{\partial \mathbf{R}(x,q,l)}{\partial x_{hk}} = c_{wk}$$

The Lagrange multiplier price associated with the hourly energy load resource balance constraint is $\lambda'_{ehp}$. This multiplier is called the hourly energy opportunity price.

Equation [3.10] for the case of the partial derivative with respect to $x_{hk}$ can now be written as

$$[3.20] \quad \beta_{py}\ c_{wk}\left(v_{hk} + \frac{1}{s}(x_{hk} - x_{mink})\right) - \lambda'_{ehp}\ c_{wk} = 0$$

Solving [3.20] for $x_{hk}$, gives

$$[3.21] \quad x_{hk} = x_{mink} + s\left(\frac{\lambda'_{ehp}}{\beta_{py}} - v_{hk}\right)$$

which is valid for $x_{hk}$ over the range $x_{mink}$ to 1.0. If [3.21] produces an $x_{hk}$ greater than 1.0 then $x_{hk}$ is set to 1.0. If [3.21] produces an $x_{hk}$ less than $x_{mink}$ then $x_{hk}$ is set to $x_{mink}$.

Equation [3.21] is the generating operating fraction shown in Figure 2.6 and defined by Equation [2.19]. The dispatch slope of the function is given by the parameter s. The term in the parentheses is the hourly net operating benefit as defined in Equation [2.15].

The hourly energy opportunity price expressed in current year y cash flow units is given by the ratio $\frac{\lambda'_{ehp}}{\beta_{py}}$. This ratio is the Lagrange multiplier price for the constraint divided by the party discount factor. The discount factor converts the opportunity price from units of present value to units of annual cost in the year y as was defined in Equation [3.8]. Generally, in the implementation of PMDAM opportunity prices are expressed in annual cost units and when necessary converted to present value units by multiplying by the party discount factor.

**Quantity Relaxation**

The calculation of the decision variable illustrated by Equation [3.21] provides a new estimate of the decision variable on each iteration. In some cases a better estimate is given by reducing or relaxing the change in the decision variable from the estimate on the previous iteration. In addition it is often useful to limit the absolute change in the decision variable on each iteration.

The relaxed change in the decision variable is given by

[3.22] $chg_x = r_x \ (x - x(n-1))$

where
- n is the index for the current iteration,
- $r_x$ is the relaxation coefficient or fraction of computed change on an iteration (Usually $r_x$ is less than 1.0),
- x is the estimate of the decision variable computed as in [3.21],
- x(n-1) is the estimate of the decision variable on the previous iteration n-1,
- $chg_x$ is the relaxed change in the decision variable on iteration n.

The limited change in the decision variable requires that the absolute value of the relaxed change $chg_x$ not exceed a maximum step size. That is,

[3.23] $abs(chg_x) \leq \text{Maximum Step Size}_x$

Therefore the new limited and relaxed estimate of the decision variable on iteration n is given by

[3.24] $x(n) = x(n-1) + chg_x$

The relaxation and maximum step techniques described here are used to improve convergence and to reduce any tendency of the algorithm to oscillate wildly. The values of the relaxation coefficient and the maximum step size are set by experimentation. Low values tend to provide slow convergence to a solution. High values may result in oscillation and inability to achieve convergence to a solution.

The relaxation described here is called quantity relaxation to make a distinction from the relaxation on opportunity prices in Step 4. of the basic iterative algorithm.

**Order of Solution**

Equations [3.10] to [3.12] form a very large system of equations to be solved for the q, l and x decision variables. Many of the equations can be solved as simply as in [3.21] where no other elements of x, l or q appear in the solution. In this case the order of solution does not matter and other computational efficiency issues will dictate the order of solution.

In other cases, Equations [3.10] to [3.12] will involve common partial derivative terms so that the amount of computation can be reduced by ordering the calculations so that the partial derivative terms are easily stored and recovered. Generally this case occurs for constraints involving decision variables related to acquisition where such variables accumulate over years. The best order of solutions in these cases is usually backwards over years.

**Iterative Solution for Decision Variables**

In some cases the set of equations [3.10] to [3.12] contain nonlinear equations that are not easily solved in closed form as was the linear equation in [3.21]. One approach is to solve such equations with a iteration scheme within the overall iterative algorithm. But [3.10] to [3.12] need to be solved accurately only when the overall solution is obtained after several iterations of the overall algorithm. Therefore, an improved estimate of the solutions to [3.10] to [3.12] is sufficient on each iteration of the overall algorithm. This improved estimate can usually be found by taking only one step of an algorithm that would solve the nonlinear equation from the equation set, [3.10] to [3.12].

An example of this this nonlinear case involves equations with transmission losses where line efficiency is a nonlinear function of line load. The partial derivative of such equations also involve transmission efficiency. These equations can be solved by using the transmission efficiency from the previous iteration to estimate the solution to the equation. Transmission efficiency is then updated on each overall iteration using the estimated decision variables affecting line loading

### 3.2.4.3. Computing Constraint Error

The constraint errors are easily computed from the equations

[3.25] $\mathbf{e} = \mathbf{R}(\mathbf{x},\mathbf{q})$

The order of calculations is usually determined by computational efficiency considerations. Many equations in **R** involved accumulation of terms over years so the best order of calculation is typically forward in time.

The error terms of **e** are accumulated to provide overall measures of the rate of convergence of the algorithm.

### 3.2.4.4. Updating Opportunity Prices

At each iteration, the opportunity prices must be adjusted in a way that leads to efficient solution of the overall problem. A very powerful but expensive method of updating the the opportunity prices is Newton's method. However, Newton's method cannot be applied in full to the PMDAM solution, and other more practical techniques are used.

#### Newton's Method

Newton's method for updating the opportunity prices is developed from a Taylor series approximation to the constraint error **e**, expressed as a function of the opportunity price estimates $\lambda$. The constraint error is approximated as

[3.26] $$\mathbf{e}(\lambda) \cong \mathbf{R}(\lambda(n)) + \frac{\partial \mathbf{R}(\lambda(n))}{\partial \lambda}(\lambda - \lambda(n))$$

where

$\lambda(n)$ is the opportunity price vector on the $n^{th}$ iteration.

$\lambda$ is the proposed new opportunity price vector.

$\mathbf{R}(\lambda(n))$ is the constraint error vector on the $n^{th}$ iteration.

$\frac{\partial \mathbf{R}(\lambda(n))}{\partial \lambda}$ is the matrix of first partial derivatives of the constraint error with respect to the opportunity prices evaluated at the current value of $\lambda(n)$.

Solving [3.26] for $\lambda$ gives

[3.27] $$\lambda = \lambda(n) + \left[\frac{\partial \mathbf{R}(\lambda(n))}{\partial \lambda}\right]^{-1}\left(\mathbf{e}(\lambda) - \mathbf{R}(\lambda(n))\right)$$

#### Partial Derivatives for Newton's Method

The partial derivative of $\mathbf{R}(\lambda)$ with respect to $\lambda$ is written as

[3.28] $$\frac{\partial \mathbf{R}(\lambda)}{\partial \lambda} = \frac{\partial \mathbf{R}(\lambda)}{\partial \mathbf{x}}\frac{\partial \mathbf{x}(\lambda)}{\partial \lambda} + \frac{\partial \mathbf{R}(\lambda)}{\partial \mathbf{q}}\frac{\partial \mathbf{q}(\lambda)}{\partial \lambda} + \frac{\partial \mathbf{R}(\lambda)}{\partial \boldsymbol{l}}\frac{\partial \boldsymbol{l}(\lambda)}{\partial \lambda}$$

The partial derivatives of the decision variables with respect to the opportunity prices, $\frac{\partial \mathbf{x}(\lambda)}{\partial \lambda}$, $\frac{\partial \mathbf{q}(\lambda)}{\partial \lambda}$, and $\frac{\partial \boldsymbol{l}(\lambda)}{\partial \lambda}$ are easily computed. Typically, one or very few of the potential terms in these derivatives are non zero. For example, the partial derivative of resource operating fraction with respect to the hourly energy opportunity price in Equation [3.21] is

[3.29] $$\frac{\partial x_{hk}(\lambda_{ehp})}{\partial \lambda_{ehp}} = \beta_{py}$$
when $x_{mink} \leq x_{hk} \leq 1.0$,
and zero otherwise

The partial derivative of contract operating decision with respect to hourly energy opportunity price is similarly,

[3.30] $$\frac{\partial q_{hj}(\lambda_{shj})}{\partial \lambda_{shj}} = \sigma$$
when $0.0 \leq q_{hj} \leq 1.0$,
and zero, otherwise.

where

$\sigma$ is a parameter of the contract cost function (see Equation [3.34]).

The partial derivatives of the constraint error with respect to the decision variables, $\frac{\partial \mathbf{R}(\lambda)}{\partial \mathbf{x}}$ and $\frac{\partial \mathbf{R}(\lambda)}{\partial \mathbf{q}}$, are also easily computed. For example, the partial derivative of the hourly load resource balance with respect to the hourly operating fraction in Equation [3.18] was seen to be $c_{wk}$ for the hour h and zero for all other hours.

The partial derivative of the hourly load resource balance with respect to the hourly contract quantity is developed in Section 3.3.5. The partial derivative is simply 1.0 for the buyer and -1.0 for the seller for the hour h and zero for all other hours.

These partial derivative terms can be combined as in [3.28] to compute $\frac{\partial R(\lambda)}{\partial \lambda}$, which is and N by N matrix where N is the number of constraints in the model. The resource terms will contribute only to the diagonal terms in this matrix. The contract terms will contribute to both diagonal and off diagonal terms. There will be many zero terms in the matrix.

Despite the special structure of the $\frac{\partial R(\lambda)}{\partial \lambda}$ matrix, it is not feasible to calculate new opportunity prices using the method implied by Equation [3.27]. There are about 100,000 constraints and associated opportunity prices in an average size version of PMDAM. Storing and inverting an N by N matrix where N is on the order of 100,000 is impossible.

**Ignoring Off-Diagonal Partial Derivatives**

One approach used in PMDAM is to ignore the off-diagonal terms in the matrix $\frac{\partial R(\lambda)}{\partial \lambda}$.

The inverted matrix, $\left[\frac{\partial R(\lambda(n))}{\partial \lambda}\right]^{-1}$ is then given by the reciprocal of the off-diagonal terms in the original matrix.

The result is the simple form of updating the opportunity prices presented in Step 4. of the basic iterative algorithm where

$$[3.31]\quad \lambda = \lambda - \alpha\, e$$

for all $\lambda$. In [3.31] $\alpha$ is a relaxation coefficient given by the diagonal term in $\left[\frac{\partial R(\lambda(n))}{\partial \lambda}\right]^{-1}$ associated with the opportunity price $\lambda$. For $\lambda$ associated with inequality constraints the value of $\lambda$ in Equation [3.31] must be restricted to the non-negative range to satisfy the optimality condition given by Equation [3.13].

**Using Small Partial Derivative Matrices**

Another approach used in PMDAM is to compute and invert small submatricies of the overall partial derivative matrix. In particular, the matrix associated with all of the load/resource balance constraints plus transmission operating capacity constraints for each single hour is computed and inverted in PMDAM. This matrix is typically a 25 by 25 matrix. Computing and inverting this matrix is very difficult and costly. Experimentation is continuing to see if the cost of computing and inverting this matrix on each iteration is justified by the reduction in total number of iterations required to obtain a satisfactory solution.

**Estimating Relaxation Coefficients**

A very simple form of the opportunity price updating algorithm is simply to estimate the values of the relaxation coefficient $\alpha$. This form is used in some portions of PMDAM because even the diagonal terms of the matrix $\frac{\partial R(\lambda)}{\partial \lambda}$ are very difficult to calculate. Estimated relaxation coefficients are used particularly where partial derivatives of the acquisition constraints and decision variables involve derivatives terms over time and are vary difficult and expensive to compute and invert.

**Selecting the Proper Direction**

The most important aspect of updating the opportunity prices within the algorithm is to move the opportunity prices in the right direction, an increase or a decrease. Too large a change causes oscillations and divergence of the algorithms. Too small a change cause slow convergence. Generally it is obvious from the economics of the problem, which direction to move the opportunity prices. The diagonal terms of the Newton's method provide a check on the economic reasoning and a potential estimate of the size of the relaxation coefficient.

**Over Relaxation and Maximum Step Size**

Because Newton's method cannot be applied to the entire set of opportunity prices and constraints, in most cases it is necessary to limit the step size and to scale down or further relax the results of any Newton's method calculations of the new opportunity prices. These maximum step and relaxation methods are similar to those applied to the decision variables as was described in Equations [3.22] through [3.24].

### 3.2.5. Bilateral Contract Decisions

Contract decision variables are of two types: unilateral and bilateral. Unilateral decision variables are determined by the cost minimization for a single party and the cost functions for the contract. Bilateral contract decision variables are determined jointly by two parties so it is not obvious how such decisions are made in the party cost minimization framework described above. Because of the importance of bilateral contracts to the formulation of the economic equilibrium view of the model, further description of how bilateral contract decisions are modelled in PMDAM is provided here.

#### 3.2.5.1. Bilateral Contract Cost Functions

The cost function in PMDAM for the buyer of economy energy is given by

$$[3.29] \quad c_{bhj}(q_{bhj},\pi_{bhj}) = \left(\pi_{bhj} + \Delta_b + \frac{1}{2\,\sigma_b} q_{bhj}\right) q_{bhj}$$

where
b indicates the buyer,
h indicates the hour,
j indicates the contract,
$c_{bhj}()$ is the buyer hourly cost of economy energy,
$q_{bhj}$ is the quantity of economy energy purchased in hour h under contract j,
$\pi_{bhj}$ is an element of the vector $\pi$ and is a contract price of energy paid by the buyer in hour h,
$\Delta_b$ is the required buyer markup or profit on the purchase,
$\frac{1}{2\sigma_b}$ is the slope of buyer effective purchase price function.

The buyer economy energy cost function [3.29] is the product of two main factors. The factor in parentheses is the effective purchase price of the quantity $q_{bhj}$. The second factor is the purchase quantity $q_{bhj}$.

The effective purchase price is the consensus contract price plus a minimum buyer markup or profit $\Delta_b$, plus a further buyer markup that increases with the quantity purchased. The consensus contract price is the price of the transaction agreed to by the buyer and the seller.

The markup terms added to the consensus contract price may or may not reflect actual monetary costs to the buyer. The buyer markup may reflect actual transaction costs not included in the price. The buyer markup also may reflect a buyer policy to consider some purchases as having a higher price than the consensus price. The buyer markup also may reflect observed behavior that indicates that buyers act as if the purchase has a higher price. The markup variables $\Delta_b$ and $\sigma_b$ are inputs data to PMDAM.

The cost function for the seller of economy energy is similar to the buyer cost function except the contract price appears as a negative cost. Typically, the effective seller cost will be negative implying net revenues to the seller. The seller contract cost function is given by

$$[3.30] \quad c_{shj}(q_{shj},\pi_{shj}) = \left(-\pi_{shj} + \Delta_s + \frac{1}{2\,\sigma_s} q_{shj}\right) q_{shj}$$

where
s indicates the seller,
$c_{shj}()$ is the seller hourly cost of economy energy,
$q_{shj}$ is the quantity of economy energy sold in hour h under contract j,
$\pi_{shj}$ is an element of the vector $\pi$ and is a contract price of energy received by the seller in hour h,
$\Delta_s$ is the required seller markup or profit on the sale,
$\frac{1}{2\sigma_s}$ is the slope of seller effective sales price function.

Further motivation for the buyer and seller contract cost functions is given in the discussion of pricing in the presence of market power in Section 3.2.6.2.

#### 3.2.5.2. Bilateral Contract Decision Functions

The contract decision function specifies the values of the contract decision variables as a function of the opportunity prices. A contract decision function is derived from the optimality conditions for each of the two parties to a contract.

Both parties to a contract must agree on the values of the contract decision variables and the contract prices. This restriction is treated in the formulation as a constraint that is directly enforced in the development of the contract decision functions. An associated Lagrange multiplier for this constraint is not defined.

Enforcing the requirement that both parties must agree any bilateral decision variables for a contract, and must agree on the contract price, provides the necessary additional assumptions to solve for the consensus contract price, $\pi_{hj}$, and quantity, $q_{hj}$.

The contract decision function for each party to a bilateral contract is developed from the buyer and seller cost functions [3.29] and [3.30] using the optimality equation [3.11]. For the buyer, the partial derivative of the first term in [3.11] is

$$[3.31] \quad \frac{\partial C(x,q,l,\pi)}{\partial q_{bhj}} = \beta_{by}\left(\pi_{bhj} + \Delta_b + \frac{1}{\sigma_b} q_{bhj}\right)$$

and, the partial derivative of the second term in [3.11] is

$$[3.32] \quad \frac{\partial R(x,q)}{\partial q_{bhj}} = 1$$

which may be seen from the hourly load resource balance constraint [3.18] where $q_{bhj}$ is a term in the element "purchases" for the buyer.

Combining [3.31] and [3.32] according to Equation [3.11] gives

$$[3.33] \quad \beta_{py}\left(\pi_{bhj} + \Delta_b + \frac{1}{\sigma_b} q_{bhj}\right) - \lambda'_{ebh} = 0$$

Solving for the buyer contract quantity and substituting $\lambda_{ebh} = \frac{\lambda'_{ebh}}{\beta_{by}}$ according to Equation [3.8] gives

$$[3.34] \quad q_{bhj} = \sigma_b(\lambda_{ebh} - \pi_{bhj} - \Delta_b)$$

Equation [3.34] states that the buyer quantity increases linearly with the difference between the buyer opportunity price, $\lambda_{ebh}$, and the contract price, $\pi_h$. The buyer contract quantity is restricted to nonnegative amounts. If Equation [3.34] results in a negative amount the result is set to zero. Thus

$$[3.35] \quad q_{bhj} = \max(0, \sigma_b(\lambda_{ebh} - \pi_{bhj} - \Delta_b))$$

Similarly the seller contract quantity is given by

$$[3.36] \quad q_{shj} = \max(0, \sigma_s(\pi_{shj} - \lambda_{esh} - \Delta_s))$$

Note that in deriving [3.36] the partial derivative

$$[3.37] \quad \frac{\partial R(x,q)}{\partial q_{shj}} = -1$$

has a negative sign because the contract quantity is a load to the seller and appears as "sales" by the seller in Equation [3.1]8.

Both parties must agree on the contract quantity and price. The prices in [3.35] and [3.36] can be set to the same value, $\pi_{hj}$. Setting the buyer and seller quantities equal, Equations [3.35] and [3.36] give

$$[3.38] \quad \sigma_b(\lambda_{ebh} - \pi_{hj} - \Delta_b) = \sigma_s(\pi_{hj} - \lambda_{esh} - \Delta_s)$$

Of course, [3.38] is only valid when the contact quantity is nonzero.

Solving [3.38] for the contract price, $\pi_{hj}$, gives

$$[3.39] \quad \pi_{hj} = \frac{\sigma_b(\lambda_{ebh} - \Delta_b) + \sigma_s(\lambda_{esh} + \Delta_s)}{\sigma_b + \sigma_s}$$

Again, [3.39] is only valid when the contract quantity is nonzero.

For the special case where the buyer and seller contract dispatch slopes are equal and the buyer and seller contract deadbands are equal Equation [3.39] can be simplified as follows:

if $\sigma_b = \sigma_s$ and $\Delta_b = \Delta_s$

$$[3.40] \quad \pi_{hj} = \frac{\lambda_{ebh} + \lambda_{esh}}{2}$$

In the simplified case of [3.40] the contract price is simply the average of the buyer and seller opportunity price.

Substituting the contract price from [3.39] back into [3.36] gives the seller contract decision function.

$$[3.41] \quad q_{shj} = \sigma_s\left[\frac{\sigma_b(\lambda_{ebh} - \Delta_b) + \sigma_s(\lambda_{esh} + \Delta_s)}{\sigma_b + \sigma_s} - \lambda_{esh} - \Delta_s\right]$$

Simplifying [3.41] gives

$$[3.42]\quad q_{shj} = \sigma_s \left[ \frac{\sigma_b(\lambda_{ebh} - \Delta_b) + \sigma_s(\lambda_{esh} + \Delta_s)}{\sigma_b + \sigma_s} - \frac{\sigma_b(\lambda_{esh} + \Delta_s) + \sigma_s(\lambda_{esh} + \Delta_s)}{\sigma_b + \sigma_s} \right]$$

Simplifying [3.42] gives

$$[3.43]\quad q_{shj} = \sigma_s \left[ \frac{\sigma_b(\lambda_{ebh} - \Delta_b) - \sigma_b(\lambda_{esh} + \Delta_s)}{\sigma_b + \sigma_s} \right]$$

Simplifying [3.43] gives

$$[3.44]\quad q_{shj} = q_{bhj} = q_{hj} = \frac{\sigma_s \sigma_b}{\sigma_b + \sigma_s} \left[ (\lambda_{ebh} - \Delta_b) - (\lambda_{esh} + \Delta_s) \right]$$

As indicated, Equation [3.44] is valid for both the seller and buyer quantity as is clear from the requirement that the buyer and seller contract quantities be equal. Again [3.44] is valid only for nonnegative contract quantities. If Equation [3.44] results in a negative quantity then the quantity should be set to zero.

For the special case where the buyer and seller contract dispatch slopes are equal and the buyer and seller contract minimum markup or profit are equal Equation [3.44] can be simplified as follows:

If $\sigma_b = \sigma_s = \sigma$ and $\Delta_b = \Delta_s = \Delta$ then

$$[3.45]\quad q_{shj} = q_{bhj} = q_{hj} = \sigma \left[ \frac{\lambda_{ebh} - \lambda_{esh}}{2} - \Delta \right]$$

This simplified contract decision function states that the contract quantity increases linearly with the net opportunity benefit of the contract, $\lambda_{ebh} - \lambda_{esh}$.

In summary, for bilateral contract decisions, the contract quantity will be nonzero when there is a net total benefit to the two parties. Large total net benefit will lead to or be required to induce larger contract quantities. The contract price will be set between the buyer and seller opportunity cost plus contract deadband. Therefore both parities will benefit if a contract transaction is beneficial. The sharing of the benefits of the transaction is determined by the relative dispatch slope and deadband parameters for the buyer and seller. In the special case where the buyer and seller dispatch slopes are equal and the buyer and seller deadbands are equal the contract price will be set so that both parties will receive equal shares of the total benefits of the contract transaction.

### 3.2.6. Supply, Demand and Market Equilibrium

PMDAM is an economic equilibrium model of a market. Each party acts in its own interest while making economic transactions with others. It is therefore useful to examine the PMDAM model using some of the traditional tools of economic analysis such as supply and demand curves.

#### 3.2.6.1. Supply and Demand Curves

Figure 3.2 shows idealized supply and demand curves for a transaction between two parties. The figure could also represent a transaction between two groups of parties.

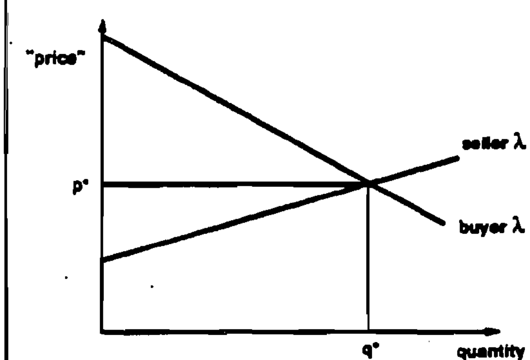



**Figure 3.2 - Market Equilibrium**

The horizontal axis represents the quantity of economy or non-firm energy transferred from a buyer to a seller in a given hour. The vertical axis represents the *price* in mills per kWh. The price scale will be used to represent opportunity prices as well as other cost and transaction prices.

The seller supply curve in Figure 3.2 shows the seller's hourly energy opportunity price as a function of the quantity q sold by the seller to the buyer. The seller opportunity price increases as a function of the sale because the seller will either use more expensive generating and contract resources to serve the sale load or reduce other higher price sales. There is no reason to expect the supply curve to be linear in PMDAM; the linear supply curve in Figure 3.2 is used to simply the graphics in this and later more complicated figures.

The buyer demand curve in Figure 3.2 shows the buyer's hourly energy opportunity price as a function of the quantity q purchased by the buyer from the seller. The buyer opportunity price decreases as a function of the sale because the buyer will either displace less expensive generating and contract resources with the purchased energy or serve other lower price sales. Similarly, the demand curve is shown as a straight line only to simplify the graphic presentation.

The quantity $q^*$ indicates the sale of energy that would minimize the total cost to the buyer and seller. At this quantity $q^*$, it is not possible to decrease the total cost because any change would cost one party more than it benefits the other. The opportunity price associated with $q^*$ is $p^*$. $p^*$ and $q^*$ can be called the least total cost price and quantity. In a fully competitive market the least total cost price and quantity is also the equilibrium market price and quantity.

The transaction $q^*$ is not necessarily the transaction that would occur in a market that is not fully competitive. Such market conditions are explored next.

### 3.2.6.2. Market Power

One important fact about wholesale power markets is that there are typically very few buyers and sellers in a given market. At one extreme a seller may have *monopoly* power in that it is the only seller to many buyers. Or, a buyer may have *monopsony* power in that it is the only buyer in a market with many sellers. These two cases are shown in Figures 3.3 and 3.4.

#### Monopoly with One Price

In the case of a seller with monopoly power and a policy that allows the use of this power, the seller will decide how much energy to sell. The buyers will then compete to purchase the energy. The buyer demand curve in Figure 3.3 indicates on the vertical axis the price p the buyers would pay for any given quantity q on the horizontal axis.

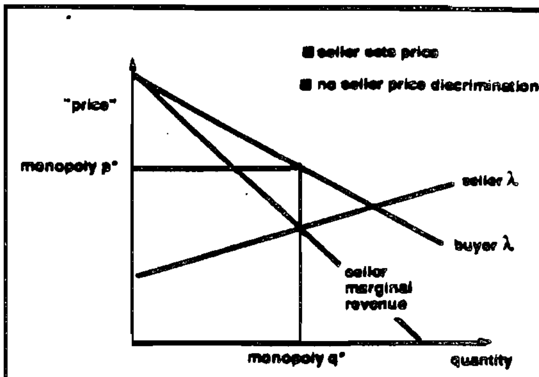



**Figure 3.3 - Monopoly Equilibrium**

If the monopoly seller charges the same price for all sales, then the revenue to the seller is simply the price multiplied by the quantity. In Figure 3.3, the revenue is indicated by the area in the box bounded by the axes and the price and quantity lines. Mathematically the revenue as a function of the quantity sold is given by

$$[3.46] \quad rev(q) = p_b(q)\ q$$

where

$rev(q)$ is the revenue from the sale of a quantity q of energy in a given hour.

$p_b(q)$ is the buyer energy opportunity price for the hour, (also called the buyer demand curve)

The partial derivative of seller revenue with respect to quantity is the seller marginal revenue curve shown in Figure 3.3 and stated mathematically as

$$[3.47] \quad \frac{\partial\, rev(q)}{\partial q} = p_b(q) + q\ \frac{\partial\, p_b(q)}{\partial q}$$

Since the partial derivative of the buyer opportunity price with respect to quantity is negative in Figure 3.3, the seller marginal revenue curve lies below the buyer opportunity price demand curve.

At the point where the seller marginal revenue equals the seller opportunity price, the revenue minus cost or net profit to the seller will be the highest possible. This point is indicated on Figure 3.3 at $q^*$ and is stated mathematically as

$$[3.48] \quad \frac{\partial\, rev(q^*)}{\partial q} = p_s(q^*)$$

(add figure to show optimal profit)

Therefore a monopolist can maximize profit ( minimize net cost to native customers ) by selling less than the least total cost amount in Figure 3.2. The price of this monopoly sale would be higher than the least total cost price.

**Monopoly with Price Discrimination**

If, however, the seller has an ability to price discriminate, then the seller can maximize profit by selling the least total cost quantity at higher prices. Price discrimination by the seller means the seller will sell a small quantity at a price equal to the highest buyer opportunity price and additional increments at successively lower prices. The last increment would be sold at at the price where the buyer and seller opportunity price curves intersect.

Under monopoly price discrimination, the quantity sold will be the same as in the least cost case. Since the sale is the same, the total cost to the two parties will be the same as in the least cost case. But, under monopoly price discrimination all of the savings from the sale will benefit the seller's native load customers. Thus the distribution of benefits and the total revenue to the seller and total cost to the buyer will be very different.

**Monopsony with One Price**

In the case of a buyer with monopsony power and a policy that allows the use of this power, the buyer will decide how much energy to purchase. The sellers will then compete to serve the buyer requested energy load. The seller supply curve in Figure 3.4 indicates on the vertical axis the price p the sellers would charge for any given quantity q on the horizontal axis.

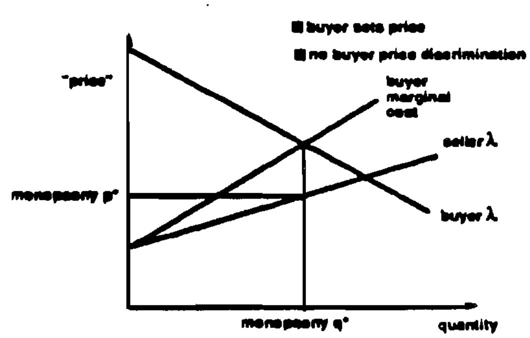



**Figure 3.4 - Monopsony Equilibrium**

If the monopsony buyer pays the same price for all purchases, then the cost to the buyer is simply the price multiplied by the quantity. In Figure 3.4 the cost is indicated by the area in the box bounded by the axes and the price and quantity lines. Mathematically the cost as a function of the quantity purchased is given by

$$[3.49]\quad cost(q) = p_s(q)\ q$$

where

$cost(q)$ is the cost of the purchase of a quantity $q$ of energy in a given hour.

$p_s(q)$ is the seller energy opportunity price for the hour, (also called the seller supply curve)

The partial derivative of buyer cost with respect to quantity is the buyer marginal cost curve shown in Figure 3.4 and stated mathematically as

$$[3.50]\quad \frac{\partial cost(q)}{\partial q} = p_s(q) + q\ \frac{\partial\ p_s(q)}{\partial q}$$

Since the partial derivative of the seller opportunity price with respect to quantity is positive in Figure 3.4, the buyer marginal cost curve lies above the seller opportunity price supply curve.

At the point where the buyer marginal cost equals the buyer opportunity price, the cost to the buyer will be the lowest possible. This point is indicated on Figure 3.4 at $q^*$ and is stated mathematically as

$$[3.51]\quad \frac{\partial cost(q^*)}{\partial q} = p_b(q^*)$$

Therefore a monopsonist can minimize the cost of a purchase by purchasing less than the least total cost amount in Figure 3.2. The price of this monopsony purchase would be lower than the least total cost price.

**Monopsony with Price Discrimination**

If, however, the buyer has an ability to price discriminate then the buyer can minimize cost by purchasing the least total cost quantity at lower prices. Price discrimination by the buyer means the buyer will purchase a small quantity at a price equal to the lowest seller opportunity price and additional increments at successively higher prices. The last increment would be purchased at at the price where the buyer and seller opportunity price curves intersect.

Under monopsony price discrimination the the total cost to the two parties will be the same as in the least cost case. But, under monopsony price discrimination, all of the savings from the purchase will benefit the buyer's native load customers.

### Imperfect Market Equilibrium

Actual electric power wholesale markets are much more complex than the idealized perfect competition, pure monopoly, or pure monopsony theories.

Parties with some market power may or may not exercise that power depending on legal, political and other economic factors. Even when a party decides to exercise market power, other parties may join together to counter the power, or apply political pressure. Economic theories of oligopolistic markets offer insight but little quantitative help.

Actual economic markets operate with lack of complete, certain knowledge about the variables describing other party economics and one's own economics. Decision making in actual markets is not cost free. Often utilities will require at least some minimum profit on a transaction in order to recover real and perceived decision making costs.

In PMDAM, market imperfections are modelled by the minimum markup $\Delta$ and dispatch slope parameter $\sigma$ of the seller contract cost function defined in Equation [3.29] and the buyer contract cost function defined in Equation [3.30]. These parameters also appear in the seller and buyer marginal contract cost equations as shown in Equations [3.34]. and [3.35].

Solving equations [3.34] and [3.35] for the buyer and seller contract price gives for the buyer,

$$[3.52] \quad \pi_{bhj} = \lambda_{ebh} - \Delta_b - \frac{q_{bhj}}{\sigma_b}$$

and for for the seller,,

$$[3.53] \quad \pi_{shj} = \lambda_{esh} + \Delta_b + \frac{q_{shj}}{\sigma_s}$$

These equations and the underlying seller and buyer opportunity prices are shown in Figure 3.5.

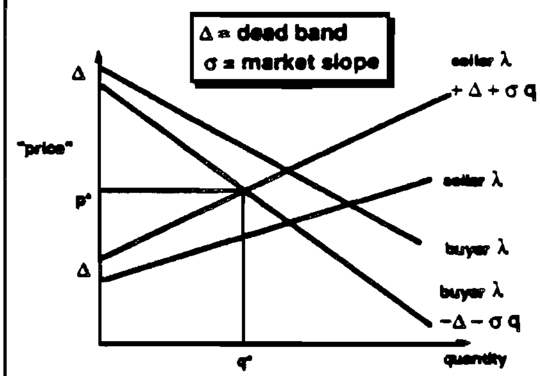



**Figure 3.5 - Imperfect Market Equilibrium**
(replace $\sigma q$ by $\frac{q}{\sigma}$ in above )

The seller marginal contract cost function in Figure 3.5 is higher than the seller energy opportunity price by an amount $\Delta + \frac{q}{\sigma}$. The $\Delta$ term represents the minimum required seller profit over its opportunity price. The term, $\frac{q}{\sigma}$ increases with q and and represents increases in marginal costs to the seller not included in the opportunity price $\lambda$. One potential source of such increased marginal cost is decreases in marginal sales revenue under monopoly pricing as was described in the discussion of monopoly pricing.

Similarly, the buyer marginal contract cost function in Figure 3.5 is lower than the buyer energy opportunity price by an amount $\Delta + \frac{q}{\sigma}$. The $\Delta$ term represents the minimum required buyer profit over its opportunity price. The term $\frac{q}{\sigma}$ increases with q and and represents increases in marginal costs to the buyer not included in the opportunity price $\lambda$. One potential source of such increased marginal cost is increases in marginal purchase cost under monopsony pricing as was described in the discussion of monopsony pricing.

The equilibrium price and quantity for the case of imperfect competition is given by p* and q* in Figure 3.5. Generally, the contract quantity under imperfect competition will be less than the least total cost or perfect market quantity given by the intersection of the seller and buyer energy opportunity price $\lambda$ curves. The imperfect competition price p* may be higher or lower than the perfect competition price.

The market parameters $\Delta$ and $\sigma$ can be determined on the basis of economic theory and estimates of the partial derivatives of the seller and buyer opportunity price curves. Or, the market parameters $\Delta$ and $\sigma$ can be determined on the basis of empirical observation of actual market prices and quantities.

The empirical approach is recommended for PMDAM because of the problem of identifying whether parties have market power and the necessary will and information to apply the market power.

In the application of PMDAM to date, rough estimates of the market parameters $\Delta$ and $\sigma$ have been made on the basis of observations of actual market conditions. No formal use of market transaction data has been applied because the necessary data is not typically available except to parties participating in the transactions and in some case regulatory authorities or special study teams. Sensitivity analysis to the market parameters in PMDAM has been performed to estimate the effect of these parameters on the model results and to suggest possible improvements in market efficiency. The results of this sensitivity analysis are reported in Section 5.

#### 3.2.6.3. Transmission Pricing

(to be completed)

#### 3.2.6.4. Cost of Service Pricing

(to be completed)

## 3.3. System of Equations View

In the description of PMDAM from the economic equilibrium view, the solution to the model is characterized by a system of simultaneous equations. This system of equations may be divided into the following two very different types: *physical* equations and *behavioral* equations.

The physical equations describe the physical relationships that the quantities and prices of the interconnected power system must satisfy. The physical equations are the constraint equations in the party optimization problem.

The behavioral equations describe how quantity and price decisions are made by each party in the power market. The behavioral equations may describe decision rules or cost minimizing or profit maximizing behavior. In the economic equilibrium view the equations derived from the Lagrangian are the behavioral equations.

### 3.3.1. Physical Equations

(to be completed)

### 3.3.2. Behavioral Equations

The behavioral equations may describe decision rules or cost minimizing or profit maximizing behavior. The behavioral equations can be designed to use only information normally available to the decision maker at the time of the decision.

## 3.4. Optimization View

It is possible to run PMDAM in a mode that determines the least-cost solution for the west coast rather than the least cost solution for each party with contracts among the parties determined on a Win-Win basis. The differences between the overall west coast optimization and the party optimization within the equilibrium west coast solution provide useful insight into the formulation of PMDAM.

### 3.4.1. Optimization Problem

The formulation of PMDAM as an overall optimization problem is similar to the formulation of the individual party optimization problems described in the discussion of the equilibrium view of the model.

#### 3.4.1.1. Objective Function

(to be completed)

#### 3.4.1.2. Decision Variables

(to be completed)

### 3.4.2. Lagrangian Formulation of the Solution

(to be completed)

### 3.4.3. Interpretation

(to be completed)

## 3.5. Simulation View

A simulation model is defined here as a model that attempts to simulate the decisions and outcomes that would occur in the actual market given the model inputs.

## 3.6. Uncertainty

(to be completed)

### 3.6.1. Monte Carlo Approach

(to be completed)

### 3.6.2. Conditional Uncertainty and Forecasts

(to be completed)

### 3.6.3. Conditional Opportunity Prices

(to be completed)

# 4. Implementation of the Model

## 4.1. Overview of the Software

The PMDAM model is implemented in a set of FORTRAN programs. Figure 4.1 shows the important components of the software and the overall flow of input data and output reports.

At the top left of Figure 4.1, the model definition files specify the model dimensions and variables used in the PMDAM programs and input and output files. The definition files feed into the common block build program (BUILDC) that creates a series of FORTRAN common block files. These common block files define the model dimensions and variables in a form that can be used directly in the FORTRAN programs.

A set of FORTRAN subroutines defining the model control logic and equations is indicated at the middle left of Figure 4.1. These FORTRAN subroutines are compiled with the common block files to form the PMDAM executable program shown at the center of the figure.

Input data files describing the economic, physical and other input parameters of the model are indicated at the bottom left of the figure. These input files are feed into the PMDAM executable program to specify a given run of PMDAM. As PMDAM runs, it creates a set of binary files that contain detailed output from the model. These same binary files can be used to restart a run of PMDAM to carry out additional iterations. This two way flow of information between the binary files and the PMDAM executable program is indicated by double arrows in the figure. Since PMDAM uses an iterative scheme, this ability to restart a run is very important. In addition, the binary files are used as temporary data memory as the iterations proceed.

PMDAM can also create a series of debugging and log files used to study the operation of PMDAM and to aid in tuning the

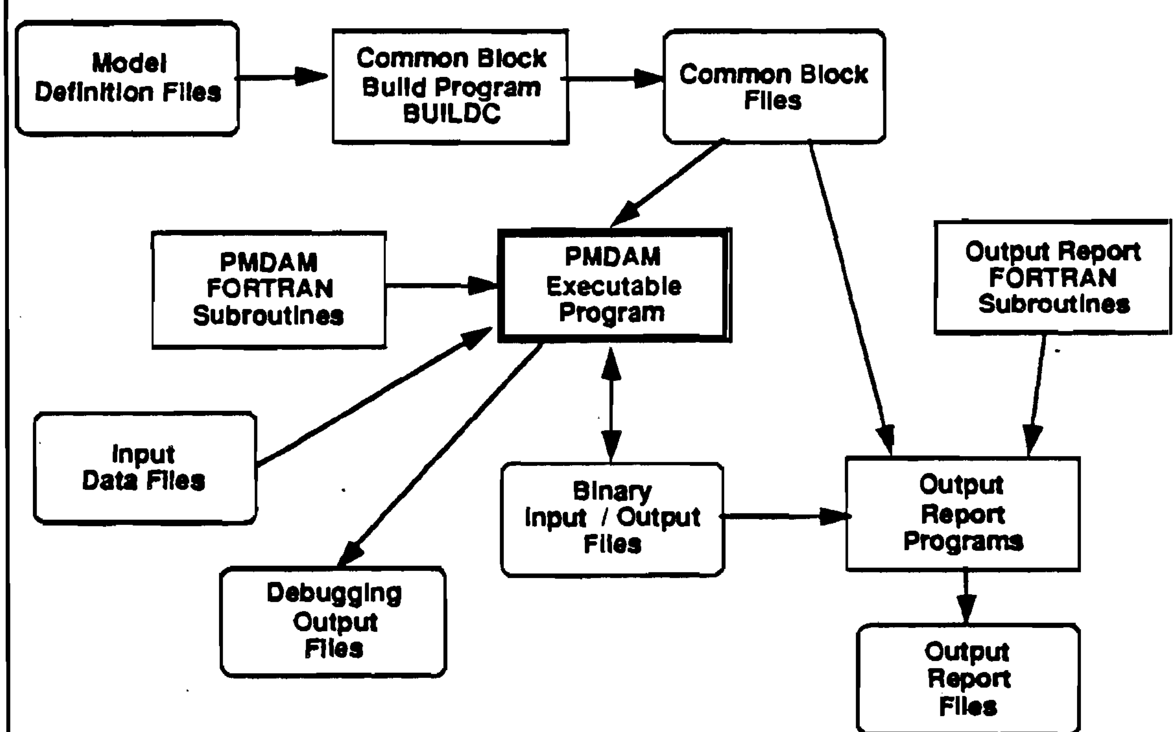



Figure 4.1- PMDAM Major Files and Programs

control parameters of the PMDAM algorithm. These control parameters are also part of the PMDAM input data files.

The binary files created by the PMDAM executable program also can be read by output report programs. The output report programs are created from FORTRAN subroutines and the common block files using a compilation process similar to the process used to create the PMDAM executable program. The resulting output report files are indicated at the bottom right of the figure.

## 4.2. Data Structures

The potential large size and complexity of the data associated with PMDAM requires a well-organized structure for managing this data. This structure must efficiently store the data, allow fast input and output from computer disks to the computer processor, allow PMDAM runs to be restarted to carry out additional iterations, and allow output reports with great detail.

The PMDAM data structure determines how variables are named, stored, and accessed both by FORTRAN subroutines and output programs. Figure 4.2 provides an overview of the PMDAM data structures.

**Figure 4.2 - PMDAM Data Structures**

### 4.2.1. Variable Names

Most variable names in PMDAM are defined using up to five characters. The use of five characters is restrictive in that it often leads to rather cryptic variable names. But, the use of only five characters simplifies the software for handling input and output data and facilitates the future conversion of the model software to FORTRAN compilers where variable names are required to be six characters or less.

Variables are defined in the file, DATA.DEF using the five character variable name. A longer name, up to 32 characters, is also provided in this file to document the variable names and to be used in output reports.

Appendix B includes an alphabetically sorted listing of the DATA.DEF file. This listing shows each variable's short name, long name, units, FORTRAN common block number, and the dimensions over which the variable is indexed. The common block number is used to group the variables. For example, all variables in the input data files are defined in common block 0.

Within the PMDAM FORTRAN code, a dollar sign is appended to the five character variable name. For example, the variable RESCP, standing for resource nameplate capacity is denoted by RESCP$ in the FORTRAN code. The dollar sign symbol distinguishes from other FORTRAN local variables those input/output variables defined in DATA.DEF and managed by the special PMDAM data management software.

### 4.2.2. Dimensions

The key organizing concept for the data, computer code, and output reports is the concept of dimensions. All data in PMDAM are organized in multi-dimensional variables, or arrays. Variables with only one dimension are vectors and variables with zero dimensions are scalars. As mentioned above, variables in the model are defined using dimensions in the file DATA.DEF.

Typical dimension names are PARTY, RESRC, (resource), and YEAR. Dimensions are defined in the file DIMENSION.DEF. A listing of the dimensions in PMDAM is shown in Appendix A. This listing shows the dimension's short name, long name, lower bound and upper bound. Dimension short names may have up to six characters and any name may be used to index the dimensions of the variables within the FORTRAN code.

Each dimension has both an upper and lower bound. The PARTY dimension ranges from 1 to MAXPTY. The value of the upper bound, MAXPTY, is defined in the file SIZE.DEF. It should be noted that PMDAM also computes an actual upper limit, i.e. LSTPT (last party), that indicates the actual range of the dimension used in a given model run. The value of LSTPT must not exceed the value of MAXPTY.

### 4.2.3. Output Dimensions

Some variables in PMDAM are have many dimensions and therefore require considerable disk storage. However it is not always necessary the have all elements of the variable stored in the processor's active memory. For example, many variables vary by game, and are computed by game. Such variables can be written out for each game and not stored by game within active memory. In PMDAM, those dimensions of a variable used only on the disk file are called output dimensions.

The DATA.DEF listing shown in Appendix A indicates the output dimensions for each variable. Output dimensions are the left of the exclamation symbol, for those variables with output dimensions. Only the GAME dimensions, and the time dimensions, YEAR, MONTH, WEEK, DAY and HOUR may be used as output dimensions.

### 4.2.4. Pointer Variables

Some variables in PMDAM require a very large amount of space if stored by the natural dimensions. For example, parties may own resources in more than one region. Therefore it is natural to define the variable, RESCPS, (Resource Nameplate Capacity) by RESRC, REGION, PARTY, MONTH, YEAR, and GAME.

Instead an indirect addressing scheme is used, wherein another dimension GRESRC, (global resource) is used instead of the dimensions RESRC, REGION and PARTY. For each resource owned by a party in a given region, a single index into the GRESRC dimension is defined. Then pointer variables, PTYGR and REGGR are used to specify the party and region associated with each value of GRESRC. Also another pointer variable (an array), GRSPR is also used to point from a given party and resource to the associated value of GRESRC.

The advantage of this indirect addressing scheme is that a party typically owns resources in only one or two regions. Also not all parties own all resource types in each region. In the the current PMDAM model the size of the GRESRC dimension used to store the pointer variables is about 140. The size of the arrays that would be required to store resource data by party and regions is given by the the product of the dimensions region(5), party(13), and resource(13). This product is 855. The ratio of these two numbers indicates the substantial savings by using this addressing scheme, which is a variation of a standard programming technique.

### 4.2.5. Building Common Blocks

The common block build program, BUILDC, takes a series of definition files and constructs a series of FORTRAN common blocks and other declarations that are used by the input, solution and output programs in the model to store and pass data among subroutines and programs.

The BUILDC program must be rerun when any information in the definition files is changed. This creates a new set of common blocks and other declarations. Then the FORTRAN PMDAM code and output report code must be compiled again to reflect the changes. Typically, this process is used only during development or to create a new version of the model capable of modeling a substantially different number of games, years, months ,weeks, days, hours, regions, or resources

## 4.3. Computational Flow

PMDAM solves a set of simultaneous equations using an iterative algorithm. In this section we will describe the order in which the calculations within PMDAM are carried out and the major subroutines and control variables used to achieve a solution.

### 4.3.1. Overall Flow of Control

The PMDAM code is written in FORTRAN and the overall order of calculations is determined by a series of nested loops. The structure of these loops and the major actions performed within each loop are outlined in Figure 4.2. The figure illustrates only the general concepts in the flow of control in the model. In the actual implementation of the model, the order of some computations is different in minor ways from that shown in Figure 4.2. This difference in flow of control has no effect on the model results and is implemented for programming convenience and computational efficiency.

**Read Data Files**
**Translate Data**
**Compute Random Variables**
Iteration Loop Begin
  Game Loop Begin
    Year Loop Begin
    **Acquire Resources**
      Month Loop Begin
      **Acquire Contracts**
      **Schedule Maintenance**
        Week Loop Begin
        **Commit Resources**
          Day Loop Begin
            Hour Loop Begin
            **Operate Resources**
            **Operate Contracts**
            **Operate Transmission**
            **Serve Native Loads**
            Hour Loop End
          Day Loop End
        Week Loop End
      Month Loop End
    Year Loop End
  Game Loop End
Iteration Loop End

**Figure 4.2 Flow of Control**

First, at the top of Figure 4.2, the flow of control begins by reading the data files. Second this data is translated into the form required by the model. Pointer variables are defined, time dependent variables are converted from input time dimensions to model time dimensions, and calculations that need only be carried out only once are performed. Third, the random variables, hydro inflows, loads, fuel price and resource availability are computed. These random variables are computed for all games and appropriate time periods. Computing and storing the random variables before the iteration loop assures that the same values of the random variables are used on each iteration.

### 4.3.1.1. Main Iteration Loop

Next the main iteration loop begins. The iterations are repeated for a fixed number of iterations or until certain convergence criteria are obtained. All remaining calculations and loops occur within the iteration loop.

For all loops represented in Figure 4.1, both the beginning and the end of the loop are indicated in the figure because important calculations are carried out at these points.

At the beginning of each loop selected variables are initialized or read from binary files. Also the loop counter is set to iterate over the appropriate range of each loop's index variable.

At the end of each loop

1 quantity variables are accumulated over time (i.e. daily quantities are computed from hourly quantities),
2 constraint balances are determined,
3 new opportunity price $\lambda$'s are computed, and
4 selected variables are written to binary output files.

Variables are written to binary files at the end of an iteration for two reasons.

5 on each iteration to reuse available computer memory for the next year or game.
6 on the last iteration to save the model results for interpretation by the output programs.

### 4.3.1.2. Acquire Generation Resources

Within the iteration loop is a series of nested loops over games, years, months, weeks, days and hours. For each game and year, generating resource acquisition decisions for all parties are made. A resource once acquired continues to be available in future years. Resources are assumed to be available for operation after a fixed construction and planning time and become available on the first day of the calendar year.

In determining the amount and type of resources to acquire in each year, the resource acquisition logic makes use of $\lambda$'s associated with both the acquisition and operating constraints. On each iteration, the $\lambda$'s computed on the previous iteration, or estimated on the first iteration, are available. Thus, in a given year, the $\lambda$'s for all future year's and all games are available for use by the model's decision making logic.

Based on the opportunity price $\lambda$'s, the party marginal levelized benefit of each resource is compared to the levelized cost of the resource. Resources with greater net benefit will tend to be acquired on successive iterations until the marginal net benefit declines to the point where no additional resources are acquired. The marginal net benefit of the resource is computed as an estimate of the conditional expected net benefit by using probability weighted opportunity price information from all games of the previous iteration.

### 4.3.1.3. Acquire Contracts

For each game, year and month, contract decisions are made. In contrast to generating resource acquisitions, contracts may be acquired in different amounts for each single month. Long-term contracts once acquired for a given month are in force for the same month in each year of the life of the contract. The model assumes contracts are acquired with a one year lead time between the acquisition decision and first use. Typically, the model is allowed to acquire twenty year contracts and one year contracts for each month.

The levelized net benefit of contract acquisition for each party to the contract and for each game, year and month is computed from the opportunity price $\lambda$'s, in the same way that generating levelized benefits are computed. Of course the contract levelized net benefit also must account for transmission $\lambda$'s.

The contract levelized net benefits to both parties are totaled and the contract acquisition decision is based on the total. A transaction price is determined that splits the total net benefits to the two parties according to the contract slope and deadband inputs provided to the model. On successive iterations the quantity of contracts acquired is adjusted until the total levelized net benefits for each game, year, and month is in balance with the quantity of contracts acquired in that game, year, and month.

### 4.3.1.4. Schedule Maintenance

Maintenance of generating units is scheduled monthly to meet an annual maintenance requirement. Based on the operating, capacity and annual maintenance $\lambda$'s from the previous iteration a new determination of maintenance in a month is made. The maintenance is adjusted on successive iterations until the operating, acquisition and maintenance constraints are satisfied. The result is a maintenance schedule for the month that reflects annual maintenance needs as well as monthly planning reliability needs and economic conditions.

### 4.3.1.5. Commit Resources

Resources are committed to operation on a weekly basis. A resource once committed must operate at or above its minimum load operating level for the entire week.

The resource commitment decision is based on hourly energy opportunity prices from the previous iteration. When the hourly operating energy price is greater than the variable operating cost the commitment of a resource has a positive value. Otherwise, the commitment has a negative value. The net benefit is the total benefit over all hours of the week. On successive iterations the commitment of resources is adjusted until the commitment net benefits justify no further change in the commitment of generating resources to the week.

### 4.3.1.6. Operate Resources

Thermal resources are operated in each hour based on a comparison of the hourly variable operating cost with the hourly operating energy opportunity price for the node associated with a given party and region. At the end of each hour loop the hourly load resource balance is determined for each node. This balance will take into account generation, native load, contract purchases and contract sales load.

Some generating resources such as wind energy and conservation resources have fixed operating schedules which are taken into account in the hourly load resource balance.

Pumped storage resources have a constraint requiring the stored energy in the system to not violate storage capacity limits. For pumped storage resources the storage opportunity price associated with the pumped storage energy constraint is updated each day on each iteration and is compared to the hourly energy opportunity price for the node. When the hourly energy opportunity price exceeds the daily pumped storage energy opportunity price the storage unit is discharged. When the hourly energy opportunity price is less than the daily pumped storage energy opportunity price the storage unit is discharged.

Hydro resources have a constraint requiring the stored energy in the system to not violate hydro storage capacity limits. Inflow to hydro storage is specified by game, year and month. For hydro resources the opportunity price $\lambda$ associated with the hydro storage energy constraint is updated each month on each iteration and is compared to the hourly energy opportunity price for the node. When the hourly energy opportunity price exceeds the monthly hydro opportunity price the storage unit is discharged. When the hourly energy opportunity price is less than the monthly hydro opportunity price the hydro resource is operated at minimum flow requirements. Other minimum flow $\lambda$'s and hydro flow variability $\lambda$'s are considering in dispatching the hydro resource. These were described in more detail in Section 2.0.

For all resources the acquisition,maintenance and commitment decisions and the random unit availability for the hour limit the generation from the unit. Also limiting the operation of each unit is its minimum generation fraction.

##### 4.3.1.7. Operate Contracts

##### 4.3.1.8. Operate Transmission

##### 4.3.1.9. Serve Native Load

##### 4.3.1.10. Hour Loop End Calculations

##### 4.3.1.11. Day Loop End Calculations

##### 4.3.1.12.Week Loop End Calculations

##### 4.3.1.13. Month Loop End Calculations

##### 4.3.1.14. Year Loop End Calculations

##### 4.3.1.15. Game Loop End Calculations

##### 4.3.1.16. Iteration Loop End Calculations

#### 4.3.2. Major Subroutines

PMDAM

PMPREP

REDDAT

NETWRK

GAMVAR

OPGMS

AQUIRE

OPGMS

OPYRS

OP MON

OPDAYS

OPHRS

OPCONTR

OPLOAD

OPRESRC

OPTRANS

HPRICE

HYMON

ACCYR

ACCPV

#### 4.3.3. Model Controls

(to be completed)

### 4.4. Input Data

(to be completed)

#### 4.4.1. Input Data Files

The input data sets for PMDAM are provided in a series of input files, each of which can be modified by standard text editing software or produced as output from other data preparation software. Table 4.1 lists the PMDAM input data sets, their functions and the variables contained in each data file.

#### 4.4.2. Reading Input Data

Input data is read into PMDAM by a standard input subroutine, REDDAT. This subroutine follows a number of conventions that must be followed in preparing the data.

#### 4.4.3. Preparing Input Data

(to be completed)

### 4.5. Output Reports

(to be completed)

### 4.6. Hardware Requirements

(to be completed)

### 4.7. Running PMDAM

(to be completed)

# 5. Applications of the Model

## 5.1. Illustrative Applications

(to be completed)

### 5.1.1. West Coast Market Overview

(to be completed)

#### 5.1.1.1. Year 2000 Monthly Peak Demand

(to be completed)

#### 5.1.1.2. August Peak Load vs. Firm Capacity

(to be completed)

#### 5.1.1.2. Annual Energy Load vs. Firm Generation

(to be completed)

#### 5.1.1.3. August Nameplate Generating Capacity by Type

(to be completed)

#### 5.1.1.4. Annual Firm Energy Generation by Type

(to be completed)

#### 5.1.1.5. Actual Annual Energy Generation by Type

(to be completed)

### 5.1.2. Regional Market Overview

(to be completed)

#### 5.1.2.1. Year 2000 Monthly Peak Demand by Region

(to be completed)

#### 5.1.2.2. August Peak Demand by Region

(to be completed)

#### 5.1.2.3. January Peak Demand by Region

(to be completed)

#### 5.1.2.4. Annual Firm Energy Load by Region

(to be completed)

#### 5.1.2.5. Nameplate Capacity by Type and Region

(in peak month)

(to be completed)

#### 5.1.2.6. Peak Demand vs. Nameplate Capacity by Region

(in peak month)

(to be completed)

#### 5.1.2.7. Annual Energy Load vs. Firm Generation by Region

(to be completed)

#### 5.1.2.8. Net Annual Exports by Region

(to be completed)

#### 5.1.2.9. Net Monthly Firm Exports by Region

(to be completed)

#### 5.1.2.10. Net Monthly Capacity Exports by Region

(to be completed)

### 5.1.3. Transmission Use

(to be completed)

### 5.1.4. Opportunity Prices

(to be completed)

## 5.2. Possible Applications

(to be completed)

# APPENDIX A - VARIABLES CROSS REFERENCE

## Operating Opportunity Prices

| Documentation Variable Name | Documentation Symbol | Code Short Name | Code Long Name |
|---|---|---|---|
| node hourly energy opportunity price | $\lambda_e$ | NODMV$ | NODE MARGINAL VALUE |

## Acquisition Opportunity Prices

| Documentation Variable Name | Documentation Symbol | Code Short Name | Code Long Name |
|---|---|---|---|
| party annual firm energy opportunity price | $\lambda_f$ | AQEMB$ | acquisition energy marg. benef |
| party monthly firm capacity opportunity price | $\lambda_c$ | AQCMB$ | acquisition cap marg. benef |

# APPENDIX B - CONSTRAINTS AND OPPORTUNITY PRICES

This appendix lists all of the constraints and associated opportunity prices in PMDAM. For each constraint the applicable dimensions are listed. Also included is a reference to the equation number used in the main body of this document where further discussion of the constraint may be found.

To simplify the presentation in this appendix, English names without subscripts are used for variables. There will be one scalar equation and one scalar opportunity price in the model for each possible combination of dimension variables. Not all variables in a constraint necessarily will vary by the indicated equations. Careful interpretation of the variables is also necessary. For example, generation in Equation [B-1] refers to total generation at a node as is indicated by the dimensions associated with the equation and not generation by resource as is used elsewhere in this document.

## Operating Constraints and Opportunity Prices

| Constraint | Opportunity Price | |
|---|---|---|
| **[B-1] Hourly Energy Load Resource Balance** | | |
| Dimensions: node, hour, day, month, year, game | | |
| generation - native load - sales + purchases = 0 | $\lambda_e$ | [2.4] |
| **[B-2] Pumped Storage Energy Limits** | | |
| Dimensions: pumped storage, hour , day, month, year, game | | |
| stored pumped energy $\geq$ 0 | $\lambda_{Sl}$ | [2.4] |
| stored pumped energy $\leq$ upper pumped energy limit | $\lambda_{Su}$ | [2.4] |
| **Storage Energy Opportunity Price** ( computed from [B-2] ) | | |
| Dimensions: pumped storage, hour, day, month, year, game | | |
| $\lambda_S = \lambda_S\,(\text{hour} + 1) - \lambda_{Su} + \lambda_{Sl}$ | $\lambda_S$ | [2.4] |
| **[B-3] Hydro Storage Capacity** | | |
| Dimensions: hydro, month, year, game | | |
| stored hydro energy $\geq$ lower hydro energy limit | $\lambda_{sl}$ | [2.4] |
| stored hydro energy $\leq$ upper hydro energy limit | $\lambda_{su}$ | [2.4] |
| **Hydro Energy Opportunity Price** ( computed from [B-3] ) | | |
| Dimensions: hydro, month, year, game | | |
| $\lambda_H = \lambda_H\,(\text{month} + 1) - \lambda_{su} + \lambda_{sl}$ | $\lambda_H$ | [2.4] |

**[B-4] Hydro Minimum Discharge**
Dimensions: hydro, month, year, game

hydro monthly discharge ≥ minimum monthly hydro discharge $\lambda_D$ [2.4]

**[B-5] Hydro Energy Daily Variability**
Dimensions: hydro, day, month, year, game

daily variability (hydro hourly discharge)

≤ max hydro daily variability $\lambda_{vd}$ [2.4]

where

daily variability (hydro hourly discharge) =

$$\frac{\text{daily standard deviation (hydro hourly discharge)}}{\text{daily average (hydro hourly discharge)}}$$

**Hydro Energy Hourly Variability opportunity price**
( computed from [B-5] )
Dimensions: hydro, hour, day, month, year, game

$$\lambda_{vh} = \lambda_{vd} \frac{\partial \text{ daily variability}_d}{\partial \text{ hydro hourly discharge}_h}$$ $\lambda_{vh}$ [2.4]

**[B-6] Resource Maintenance**
Dimensions: resource, year, game

$$\sum_{m=1}^{MAXMON} \text{maintenance fraction}_m = \text{annual maintenance fraction}$$ $\lambda_M$ [2.4]

**[B-7] Contract Link Annual Energy Limit**
Dimensions: annual energy limit link, month, year, game

annual link energy ≤ annual link energy limit $\lambda_{la}$ [2.4]

**[B-8] Contract Link Monthly Energy Limit**
Dimensions: monthly energy limit link, week, month, year, game

monthly link energy ≤ monthly link energy limit $\lambda_{lm}$ [2.4]

**[B-9] Contract Link Weekly Energy Limit**
Dimensions: weekly energy limit link, week, month, year, game

weekly link energy ≤ weekly link energy limit $\lambda_{lw}$ [2.4]

**[B-10] Contract Link Daily Energy Limit**
Dimensions: daily energy limit link, day, month, year, game

daily link energy ≤ daily link energy limit $\lambda_{ld}$ [2.4]

**[B-11] Contract Link Capacity Return Energy Limit**
Dimensions: 24hr capacity link, day, month, year, game

daily return link energy = daily link energy $\lambda_{lr}$ [2.4]

**[B-12] Party Transmission Capacity Limit**
Dimensions: gtrans, hour, day, month, year, game

party transmission load $\leq$ party available transmission capacity $\lambda_t$ [2.4]

## Acquisition Constraints and Opportunity Prices

| Constraint | Opportunity Price | |
|---|---|---|
| **[B-13] Annual Energy Firmness** | | |
| Dimensions: party, month, year, game | | |
| generating firm energy + contract firm energy - native firm load - contract firm load = 0 | $\lambda_f$ | [2.4] |
| **[B-14] Annual Pool LOLP** | | |
| Dimensions: pool, year, game | | |
| annual pool LOLP ≤ annual pool LOLP requirement | $\lambda_A$ | [2.4] |
| **[B-15] Monthly Party LOLP** | | |
| Dimensions: month, year, game | | |
| monthly party LOLP = monthly average party LOLP | $\lambda_r$ | [2.4] |

**Opportunity Prices Computed from [B-14] and [B-15]**
**Monthly Resource Capacity**
Dimensions: gresrc, month, year, game

$$\lambda_r = \lambda_A \frac{\partial \text{ annual pool LOLP}}{\partial \text{ resource capacity}} + \lambda_L \frac{\partial \text{ monthly party LOLP}}{\partial \text{ resource capacity}} \qquad \lambda_r \qquad [2.4]$$

**Monthly Contract Link Capacity**
Dimensions: link, month, year, game

$$\lambda_c = \lambda_a \frac{\partial \text{ annual pool LOLP}}{\partial \text{ link capacity}} + \lambda_l \frac{\partial \text{ monthly party LOLP}}{\partial \text{ link capacity}} \qquad \lambda_c \qquad [2.4]$$

**[B-16] Committed Party Transmission**
Dimensions: gtrans,month, year, game

committed party transmission ≤ party available transmission capacity $\qquad \lambda_T \qquad$ [2.4]

# APPENDIX C - COST FUNCTIONS

This appendix lists the important cost functions in PMDAM. The cost functions determine the cost to each party of system operation and acquisition of resources and contracts. The cost function are also used to derive the behavioral decision functions listed in Appendix E using the methodology described in Section 3.

## Operating Cost Functions

Dimensions : hour day month year game

[C-1]

generation cost = variable operating cost × minimum operating fraction
× weekly commitment fraction
+ ( variable operating cost + additional variable operating cost )
× ( resource operating fraction - minimum operating fraction )
× weekly commitment fraction

additional variable operating cost = resource cost slope
× ( resource operating fraction - minimum operating fraction )

$$\text{resource cost slope} = \frac{1}{2 \times \text{resource dispatch slope}}$$

Documentation Equation : [3.16]

$$c_{hk}(x_{hk}) = v_{hk}\ x_{mink}\ c_{wk} + (v_{hk} + \frac{1}{2s}(x_{hk} - x_{mink}))\ (x_{hk} - x_{mink})\ c_{wk}$$

## Acquisition Cost Functions

Dimensions : hour day month year game

# APPENDIX D - SCARCE RESOURCE EQUATIONS

This appendix lists the scarce resource equations in PMDAM. The scarce resource equations express the relations between the decision variables and the terms in the constraint equations listed in Appendix B.

## Operating Scarce Resource Equations

Dimensions : gresrc hour day month year game

**[F-1]**

generation = resource operating fraction × ***daily availability fraction*** ×
weekly commitment fraction × monthly not on maintenance fraction ×
**monthly capacity fraction** × installed capacity

## Acquisition Scarce Resource Equations

Dimensions : gresrc hour day month year game

# APPENDIX E - BEHAVIORAL DECISION EQUATIONS

This appendix lists the important behavioral decision equations in the model. The behavioral decision equations express the decision variables as a function of the opportunity prices and other input variables. The opportunity prices in each decision equations are shown in italic type in this appendix. Bold type is used to denote vector quantities where at least one dimension of the variable is not subscripted.

## Operating Behavioral Decision Equations

Dimensions Used: gresrc, node, hour, day, month, year, game. (r,n, h,d,m,y,g)

Pointers Used : node given gresrc n(r)

Pumped storage resource given gresrc P(r)

Hydro resource given gresrc H(r)

Allowable range of result : **minimum resource operating fraction**(r) to 1.0

## Resource operating fraction

[E-1] resource operating fraction $_{rhdmyg}$ =

minimum resource operating fraction $_{r}$ +

resource dispatch slope $_{r}$ × resource net operating benefit $_{rhdmyg}$

+ inflation $_{y}$

[E-1a] For thermal resource

resource net operating benefit $_{rhdmyg}$ =

*energy opportunity price* $_{n(r)hdmyg}$ −
resource variable operating cost $_{rmyg}$

[E-1b] For pumped storage resource

resource net operating benefit $_{rhdmyg}$ =

*energy opportunity price* $_{n(r)hdmyg}$ −

*pumped storage energy opportunity price* $_{P(r)dmyg}$ −
resource variable operating cost $_{rmyg}$

[E-1c] For hydro resource

resource net operating benefit $_{rhdmyg}$ =

*energy opportunity price* $_{H(r)hdmyg}$ −

*hydro energy opportunity price* $_{H(r)myg}$ −

*hydro minimum discharge opportunity price* $_{H(r)myg}$ −

*hydro variability opportunity price* $H(r)_{hdmyg}$ –
resource variable operating cost $_{rmyg}$

**Contract Link Operating Fraction**
**[E-1]** For economy link

## Acquisition Behavioral Decision Equations
## Resource Nameplate Additions

resource additions $_{ryg}$ = resource acquisition slope $_r$ ×
( levelized net resource benefits $_{ryg}$ − resource acquisition deadband )
+ inflation $_y$

levelized net resource benefits $_{ryg}$ = levelized capacity benefits $_{ryg}$ +
levelized energy firmness benefits $_{ryg}$ +
levelized net operating benefits $_{ryg}$ −
levelized fixed operating costs $_{ryg}$ −
levelized capital costs $_{ryg}$

levelized capacity benefits $_{ryg}$ =
lev (**annual resource capacity benefits** $_{rg}$, y, endyr, p)

levelized energy firmness benefits $_{rmyg}$ =
lev (**annual resource energy firmness benefits** $_{rg}$, y, endyr, p)

levelized net operating benefits $_{ryg}$ =
lev (**annual resource net operating benefit** $_{rg}$, y, endyr, p)

levelized fixed operating costs $_{ryg}$ =
lev (**annual resource fixed operating cost** $_{rg}$, y, endyr, p)

levelized capital costs $_{ryg}$ =
lev (**annual resource capital cost** $_{rg}$, y, endyr, p)

where

$$\text{lev}(\mathbf{x}, y1, y2, p) = \frac{\text{present value}(\mathbf{x}, y1, y2, p)}{\text{present value}(\textbf{inflation}, y1, y2, p)}$$

$$\text{present value}(x_y, y1, y2, p) = \sum_{y=y1}^{y2} x_y \times \text{discount factor}_{py}$$

$$\text{present value}(\textbf{inflation}, y1, y2, p) = \sum_{y=y1}^{y2} \text{inflation}_y \times \text{discount factor}_{py}$$

annual resource capacity benefits $_{ryg}$ =

$$\sum_{m=1}^{MAXMON} \textit{resource capacity opportunity price}_{rmyg} \times \text{maintenance fraction}_{rmyg}$$

annual resource energy firmness benefits $_{ryg}$ =
*energy firmness opportunity price* $_{ryg}$ ×
resource annual firm energy fraction $_{ryg}$

annual resource net operating benefit $_{ryg}$ ( see **[E-1]** )

# APPENDIX F - PMDAM DIMENSIONS

```
* NAME   LONG NAME                           RANGE
*------- ----------------------------------- -------------
* .. TIME DIMENSIONS FOR INTERNAL/OUTPUT
 YEAR   CALENDAR YEAR                        MINYR:MAXYR
 MONTH  CALENDAR MONTH                       1:MAXMON
 WEEK   WEEK OF MONTH                        1:MAXWEK
 DAY    DAY OF MONTH                         1:MAXDAY
 WKDAY  DAY OF WEEK                          1:MAXWD
 HOUR   HOUR BLOCK OF DAY                    1:MAXHR
* .. TIME DIMENSIONS FOR INPUT DATA
 DYEAR  DATA CALENDAR YEAR                   MINDYR:MAXDYR
 DMONTH DATA CALENDAR MONTH                  1:MAXDMN
 DWEEK  DATA WEEK OF MONTH                   1:MAXDWK
 DDAY   DATA DAY OF MONTH                    1:MAXDDY
 DWKDAY DATA DAY OF WEEK                     1:MAXDWD
 DHOUR  DATA HOUR BLOCK OF DAY               1:MAXDHR
* .. SYSTEM DIMENSIONS
 PARTY  PARTY                                1:MAXPTY
 DPARTY DATA PARTY                           1:MAXDPT
 FPARTY 'FROM' PARTY                         1:MAXPTY
 TPARTY 'TO' PARTY                           1:MAXPTY
 REGION GEOGRAPHIC REGION                    1:MAXRGN
 FREGON 'FROM' REGION                       1:MAXRGN
 TREGON 'TO' REGION                          1:MAXRGN
 SPREGN SNOWPACK REGION                      1:MAXSPR
 FCREGN HYDRO FORECAST REGION                1:MAXHFR
*     SET MAXHFR = MAXRGN + MAXSPR
 POD    POINT OF DELIVERY                    1:MAXPOD
 TRANS  TRANSMISSION LINK                    1:MAXTRN
 GTRANS GLOBAL TRANSMISSION LINK             1:MAXGTR
 TOWNER TRANSMISSION LINK OWNER              1:MAXOWN
 RESRC  GENERATING RESOURCE                  1:MAXRES
 PROJ   GENERATING PROJECT                   1:MAXPRJ
 LOAD   POWER LOAD                           1:MAXLOD
 HYDRO  HYDRO RESOURCE                       1:MAXHYD
 PSTORG PUMPED STORAGE RESOURCE              1:MAXPST
 NPSTOR NODE PUMPED STORAGE RESOURCE         1:MAXNPS
 PRATE  POWER RATE INDEX                     1:MAXPRT
 CONTR  CONTRACT AMONG PARTIES               1:MAXCON
 FUEL   TYPE OF FUEL                         1:MAXFUL
 RTYPE  TYPE OF RESOURCE                     1:MAXRTP
 LEVEL  RESOURCE SUPPLY CURVE LEVEL          0:MAXLVL
 WATER  HYDRO INFLOW LEVEL                   1:MAXWAT
 STRLVL HYDRO STORAGE LEVEL                  0:MAXHSL
 CONADJ CONTRACT ADJUSTMENT INDEX            0:MAXADJ
 PATH   PATH INDEX                           1:MAXPTH
 MPATH  METAPATH INDEX                       1:MAXMPT
 LPATH  PATH FOR METAPATH                    1:MAXPAL
 PTHLNK PATH LINK                            1:MAXPLK
 TPATH  TRANS PATH                           1:MAXTPA
 STRANS SPECIFIC TRANS LINK FOR PATH         1:MAXSTL
 ADDNO  CAPACITY ADDTION LINE NUMBER         1:MAXADN
 POOL   POOL OF PARTIES                      1:MAXPOL
 PLPTY  PARTY INDEX FOR POOL                 1:MAXPPT
 EMISON ENVIRONMENTAL EMISSION               1:MAXEMS
 BASIN  ENVIRONMENTAL BASIN                  1:MAXBAS
* .. MODEL OPERATION DIMENSIONS
 GAME   GAME INDEX                           1:MAXGAM
* .. INTERNAL MODEL DIMENSIONS
 NODE   NODE OF SYSTEM NETWORK               1:MAXNOD
 GRES   GLOBAL RESOURCE                      1:MAXGRS
 NRESRC RESOURCE AT NODE                     1:MAXRSN
 GLOAD  GLOBAL LOAD                          1:MAXGLD
 NLOAD  LOAD AT NODE                         1:MAXNLD
 NEWRES NEW GENERATING RESOURCE              1:MAXNRS
 REGNR  REGIONAL NEW RESOURCE                1:MAXRNR
 NEWCON NEW CONTRACT RESOURCE                1:MAXNCN
 LINK   LINK BETWEEN NODES                   1:MAXLNK
 LKTYPE LINK TYPE                            1:MAXLTY
 CONLK  CONTRACT SPECIFIC LINK               1:MAXCLK
 LINKTO LINK TO NODE OR PARTY                1:MAXLTO
 LINKFR LINK FROM NODE OR PARTY              1:MAXLFR
 LINKFT LINK FROM NODE/PTY TO NODE/PTY       1:MAXLFT
 YRLMT  YEAR ENERGY LIMIT                    1:MAXYLM
 MNLMT  MONTH ENERGY LIMIT                   1:MAXMLM
 WKLMT  WEEK ENERGY LIMIT                    1:MAXWLM
 DYLMT  DAY ENERGY LIMIT                     1:MAXDLM
 MMNLMT MONTH MIN ENERGY LIMIT               1:MAXMML
 LNKLIM LINK ENERGY LIMIT(YR,MN,MM,WK,DY)    1:MAXLKL
 MNCLMT MONTHLY CAPACITY LIMIT               1:MAXMCL
 HRCLMT HOURLY CAPACITY LIMIT                1:MAXHCL
*
 CONTTO CONTRACT TO PARTY                    1:MAXCTO
 CONTFR CONTRACT FROM PARTY                  1:MAXCFR
 CONTFT CONTRACT FROM/TO PARTY               1:MAXCFT
 CONFTR CONTRACT FROM/TO REGION              1:MAXFTR
*
 ALIAS  ALIAS INDEX                          1:MAXALS
 DUMP   LIST OF OUTPUT VARIABLES             1:MAXDMP
 TIME   NUMBER OF BYTES IN TIME VARIABLE     1:TWO
 BOUND  NUMBER OF BOUNDS (UPPER & LOWER)     1:TWO
 WORD   NUMBER OF WORDS IN WORD STRING       1:MAXWRD
 DIMEN  DIMENSION NAMES                      1:MAXDIM
*MODEL MANAGEMENT DIMENSIONS
 STUDY  MODEL APPLICAITON                    1:MAXSTY
 CASE   RUN OF MODEL                         1:MAXCAS
 DECISN DECISION ALTERNATIVE                 1:MAXDEC
 SENSIT SENSITIVITY CASE                     1:MAXSEN
 DBFILE DEBUG FILE NUMBER                    1:MAXDBF
 DBCASE DEBUG FLAG CASE                     1:THREE
```

# APPENDIX G - PMDAM VARIABLES

(only about half of the variables are included in this draft)

| | | | | | |
|---|---|---|---|---|---|
| NC1MW | NEW CONTRACT (1YR) MW ADDITIONS | MW | I | 3 | NEWCON MONTH YEAR ! GAME |
| NCCON | PTR: NEW CONTRACT GIVEN CONTR | INDEX | I | 1 | CONTR |
| NCERR | NEW CONTRACT ABS ERROR | MW | I | 3 | NEWCON MONTH YEAR ! GAME |
| NCFB | NEW CONTRACT FRPTY TOT BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCFCB | NEW CONTRACT FRPTY CAP BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCFEB | NEW CONTRACT FRPTY ENR BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCFOB | NEW CONTRACT FRPTY OPR BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCFTB | NEW CONT FRPTY TRANS BENEF | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCGER | NEW CONTRACT GAME TOTAL ABS ERR | MW | R | 3 | GAME |
| NCMW | NEW CONTRACT MW ADDITIONS | MW | I | 3 | NEWCON MONTH YEAR ! GAME |
| NCNAM | NEW CONTRACT NAME | NAME | A | 0 | NEWCON |
| NCNFR | PTR: NEWCON GIVEN FROM PARTY | INDEX | I | 1 | CONTFR PARTY |
| NCNFT | PTR: NEWCON GIVEN FROM/TO PTY | INDEX | I | 1 | CONTFT FPARTY TPARTY |
| NCXMW | NEW CONTRACT CUMULATIVE MW | MW | I | 3 | NEWCON MONTH YEAR ! GAME |
| NCNTO | PTR: NEWCON GIVEN TO PARTY | INDEX | I | 1 | CONTTO PARTY |
| NCRFT | PTR: NEWCON GIVEN FROM/TO REG | INDEX | I | 1 | CONFTR FREGON TREGON |
| NCTB | NEW CONTRACT TOPTY TOT BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCTCB | NEW CONTRACT TOPTY CAP BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCTEB | NEW CONTRACT TOPTY ENR BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCTOB | NEW CONTRACT TOPTY OPR BENEFIT | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCTTB | NEW CONT TOPTY TRANS BENEF | $/KW-YR | R | 3 | NEWCON MONTH YEAR ! GAME |
| NCYER | NEW CONTRACT YEAR TOTAL ABS ERR | MW | R | 3 | YEAR ! GAME |
| NDCCP | NODE CONTRACT CAPACITY | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDCFE | NODE CONTRACT FIRM ENERGY | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDCFL | NODE CONTRACT FIRM LOAD | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDCPD | NODE CONTRACT PEAK DEMAND | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDDFL | NODE DIRECT FIRM LOAD | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDDOG | NODE DAILY OVER GENERATION | AVG. MW | I | 3 | NODE DAY ! MONTH YEAR GAME |
| NDDPD | NODE DIRECT PEAK DEMAND | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDERD | DAILY NODE MW AVG L/R ERROR | MW | R | 4 | NODE DAY ! MONTH YEAR GAME |
| NDERE | EXPECTED NODE MW AVG L/R ERROR | MW | R | 4 | NODE |
| NDERG | GAME NODE MW AVG L/R ERROR | MW | R | 4 | NODE GAME |
| NDERH | HOURLY NODE MW L/R ERROR | MW | R | 4 | NODE HOUR ! DAY MONTH YEAR GAME |
| NDERM | MONTHLY NODE MW AVG L/R ERROR | MW | R | 4 | NODE MONTH ! YEAR GAME |
| NDERY | YEARLY NODE MW AVG L/R ERROR | MW | R | 4 | NODE YEAR ! GAME |
| NDGCP | NODE GENERATION CAPACITY | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDGFE | NODE GENERATION FIRM ENERGY | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDHOG | NODE HOURLY OVER GENERATION | AVG. MW | I | 3 | NODE HOUR ! DAY MONTH YEAR GAME |
| NDMED | DAILY NODE MW MAX L/R ERROR | MW | R | 4 | NODE DAY ! MONTH YEAR GAME |
| NDMEE | EXPECTED NODE MW MAX L/R ERROR | MW | R | 4 | NODE |
| NDMEG | GAME NODE MW MAX L/R ERROR | MW | R | 4 | NODE GAME |
| NDMEM | MONTHLY NODE MW MAX L/R ERROR | MW | R | 4 | NODE MONTH ! YEAR GAME |
| NDMEY | YEARLY NODE MW MAX L/R ERROR | MW | R | 4 | NODE YEAR ! GAME |
| NDMOG | NODE MONTHLY OVER GENERATION | AVG. MW | I | 3 | NODE MONTH ! YEAR GAME |
| NDNAM | NODE NAME | NAME | A | 0 | NODE |
| NDRCP | NODE RESERVE CAPACITY | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDSFE | NODE SURPLUS FIRM ENERGY | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDTCP | NODE TOTAL CAPACITY | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDTFE | NODE TOTAL FIRM ENERGY | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDTFL | NODE TOTAL FIRM LOAD | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NDTPD | NODE TOTAL PEAK DEMAND | MW | I | 3 | NODE MONTH YEAR ! GAME |
| NDYOG | NODE YEARLY OVER GENERATION | AVG. MW | I | 3 | NODE YEAR ! GAME |
| NFRCN | PTR: "FROM" NODE GIVEN CONTRACT | INDEX | I | 1 | CONTR |
| NFRLK | PTR: "FROM" NODE GIVEN LINK | INDEX | I | 1 | LINK |
| NGAME | NUMBER OF GAMES | COUNTER | I | 0 | |
| NINNR | LAST INNER ITERATION | COUNTER | I | 2 | |
| NINR1 | NUM. OF INNER LOOP ITERS | COUNTER | I | 0 | |
| NINR2 | NUM. OF INNER LOOP ITERS (FINAL) | COUNTER | I | 0 | |
| NOACQ | NO AQUISITIONS FLAG | T/F | L | 0 | |
| NODGL | PTR: NODE GIVEN GLOBAL LOAD | INDEX | I | 1 | GLOAD |
| NODGR | PTR: NODE GIVEN GLOBAL RES | INDEX | I | 1 | GRES |
| NODMV | NODE MARGINAL VALUE | MILLS/KWH | R | 3 | NODE HOUR DAY MONTH ! YEAR GAME |
| NODPR | PTR: NODE GIVEN PARTY | INDEX | I | 1 | PARTY REGION |
| NODPS | PTR: NODE GIVEN PUMPED STORAGE | INDEX | I | 1 | PSTORG |
| NODSL | NODE OWN SLOPE | MW/MILL | R | 3 | NODE |
| NOUTR | NUMBER OF OUTER LOOP ITERATIONS | COUNTER | I | 0 | |
| NRAVL | NEW RESOURCE AVAILABLE | T/F | L | 0 | RESRC PARTY REGION |
| NRCAP | NEW RESOURCE INCREMETAL CAPACITY | MW | I | 3 | NEWRES YEAR ! GAME |
| NRCCP | NEW RESOURCE CUM CAPACITY | MW | I | 3 | NEWRES YEAR ! GAME |
| NRCMB | NEW RESRC CAPACITY MARG.BENEFIT | $/KW-YR | R | 3 | NEWRES YEAR ! GAME |
| NRENB | NEW RESRC ENERGY MARG.BENEFIT | $/KW-YR | R | 3 | NEWRES YEAR ! GAME |
| NRERR | NEW RESOURCE AQ ERROR | MW | I | 3 | NEWRES YEAR ! GAME |
| NRGER | NEW RESOURCE ABS AQ GAME ERROR | MW | I | 3 | GAME |
| NRMFC | NEW RESRC MARGINAL FIXED COST | $/KW-YR | R | 3 | NEWRES YEAR |
| NRMOC | NEW RESRC MARG. OPERATING COST | $/KW-YR | R | 3 | NEWRES YEAR ! GAME |
| NRMOV | NEW RESRC MARG. OPERATING VALUE | $/KW-YR | R | 3 | NEWRES YEAR ! GAME |
| NRMXR | NEW RESOURCE MAX RATE ADDITIONS | MW/YR | I | 0 | RESRC PARTY REGION |
| NRNAM | NEW RESOURCE NAME | NAME | A | 0 | NEWRES |
| NRRMB | NEW RESRC MARG. TOTAL BENEFIT | $/KW-YR | R | 3 | NEWRES YEAR ! GAME |
| NRRPR | PTR: NEW RES GIVEN RES,PTY,REG | INDEX | I | 1 | RESRC PARTY REGION |
| NRSFE | NEW RESOURCE FIRM ENERGY | AMW | I | 3 | NEWRES YEAR ! GAME |
| NRSGR | PTR: NEW RES GIVEN GLOBAL RES | INDEX | I | 1 | GRES |
| NRYER | NEW RESOURCE ABS AQ YEAR ERROR | MW | I | 3 | YEAR ! GAME |
| NTOCN | PTR "TO" NODE GIVEN CONTRACT | INDEX | I | 1 | CONTR |
| NTOLK | PTR "TO" NODE GIVEN LINK | INDEX | I | 1 | LINK |
| OGFUL | OIL/GAS FUEL TYPE NUMBER | INDEX | I | 0 | |
| OPDEL | OIL PRICE GROWTH DELTA | FRACTION | R | 3 | YEAR ! GAME |
| OPELS | FUEL PRICE/ OIL PRICE ELASTICITY | FRACTION | R | 0 | FUEL |
| OPTSC | OIL PRICE TIME SERIES CORREL. | FRACTION | R | 1 | |
| ORDCN | ORDER CONSTANT FOR LOAD UNC. | FRACTION | R | 2 | MONTH |
| OUTC | LOAD OUTAGE COST | MILLS/KWH | R | 0 | LOAD PARTY |
| OUTCC | OUTPUT CONTROL FLAG | T/F | L | 0 | DUMP |
| OUTFN | OUTAGE CHARGE ON FIRM LOADS | MILLS/KWH | R | 0 | |

| | | | | | |
|---|---|---|---|---|---|
| PANAM | NAMES OF PATHS | NAME | A | 0 | PATH |
| PANMP | PATH NAMES FOR METAPATH | NAME | A | 0 | LPATH MPATH |
| PARSK | POOL ANNUAL RISK | DAYS/YR | R | 3 | POOL YEAR ! GAME |
| PDFTR | PTR: "FROM" POD GIVEN TRANS | INDEX | I | 1 | TRANS |
| PDTTR | PTR: "TO" POD GIVEN TRANS | INDEX | I | 1 | TRANS |
| PEFF | PATH EFFICENCY BY STRANS | FRACTION | R | 3 | STRANS ! HOUR DAY MONTH YEAR GAME |
| PFCAP | PATH "FROM" CAPACITY | MW | I | 3 | PATH MONTH YEAR |
| PLLFD | PLANNING LOAD FACTOR DATA | FRACTION | R | 0 | DMONTH PARTY LOAD |
| PLNAM | POOL NAME GIVEN POOL NO. | NAME | A | 0 | POOL |
| PLNLF | PLANNING LOAD FACTOR | FRACTION | R | 2 | MONTH GLOAD |
| PLNPT | POOL NAME GIVEN PARTY NO. | NAME | A | 0 | PARTY |
| PLPT | POOL NO. GIVEN PARTY NO. | INDEX | I | 1 | PARTY |
| PLRSK | POOL MONTHLY RISK | DAYS/YR | R | 3 | POOL MONTH YEAR ! GAME |
| PLTLF | PLANT PHYSICAL LIFE | YEARS | I | 0 | RESRC |
| PLVAC | PARTY LEVELIZED AVERAGE COST | MILLS/KWH | R | 4 | PARTY GAME |
| PMB | PATH MARG. BENEFIT | $/KW-YR | R | 3 | PATH MONTH YEAR ! GAME |
| PNAME | NAMES OF PARTIES | NAME | A | 0 | PARTY |
| PNCC | PARTY NOMINAL COST OF CAPITAL | RATIO | R | 2 | PARTY YEAR |
| POCCP | POOL CONTRACT CAPACITY | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POCLM | POOL CAP LOSS MULTIPLIER | MW2/MW2 | R | 0 | POOL |
| POCPD | POOL CONTRACT PEAK DEMAND | MW | I | 3 | POOL MONTH YEAR ! GAME |
| PODCL | POOL THRML DERATE CAPACITY LOSS | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POONA | NAMES OF POINTS OF DELIVERY | NAME | A | 0 | POD |
| POOPA | TRANSFER POINT OF DELIVERY | NAME | A | 0 | PATH |
| POOTP | POINT OF DELIVERY GIVEN TPATH | INDEX | I | 2 | TPATH |
| POFPL | POOL FIRM PEAK LOAD | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POGCP | POOL GENERATING CAPACITY | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POMCL | POOL MAINTENANCE CAPACITY LOSS | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POMXE | POOL MAX RISK ERROR | DAYS/YR | R | 0 | |
| POOLT | POOL RISK T | MW | R | 3 | POOL MONTH YEAR ! GAME |
| PORLX | POOL RISK RELAXATION COEFF | $/D/D | R | 0 | POOL |
| POSNS | POOL STD DEV NET SURPLUS | MW | R | 3 | POOL MONTH YEAR ! GAME |
| POSPR | POOL SPIN RESERVE REQUIREMENT | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POUCL | POOL MEAN CAPACITY LOSS | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POUNS | POOL MEAN NET SURPLUS | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POUPL | POOL MEAN PEAK LOAD | MW | I | 3 | POOL MONTH YEAR ! GAME |
| POVCL | POOL VARIANCE CAPACITY LOSS | MW | R | 3 | POOL MONTH YEAR ! GAME |
| POVPL | POOL VARIANCE PEAK LOAD | MW*2 | R | 3 | POOL MONTH YEAR ! GAME |
| PPOCS | PARTY PV OTHER COST | $MM/YR | I | 4 | PARTY GAME |
| PPVBC | PARTY PV RATE BASE COST | $MM/YR | I | 4 | PARTY GAME |
| PPVBR | PARTY PV RATE BASE REVENUE | $MM/YR | I | 4 | PARTY GAME |
| PPVCC | PARTY PV CAPITAL COST | $MM/YR | I | 4 | PARTY GAME |
| PPVER | PARTY PV EXPORT REVENUE | $MM/YR | I | 4 | PARTY GAME |
| PPVFC | PARTY PV FIXED COST | $MM/YR | I | 4 | PARTY GAME |
| PPVIC | PARTY PV IMPORT COST | $MM/YR | I | 4 | PARTY GAME |
| PPVNC | PARTY PV NET COST | $MM/YR | I | 4 | PARTY GAME |
| PPVOC | PARTY PV OPERATING COST | $MM/YR | I | 4 | PARTY GAME |
| PPVTC | PARTY PV TRANSMISSION COST | $MM/YR | I | 4 | PARTY GAME |
| PPVTR | PARTY PV TRANSMISSION REVENUE | $MM/YR | I | 4 | PARTY GAME |
| PRATO | BASE YEAR POWER RATES | MILLS/KWH | R | 0 | PRATE |
| PRBAC | PARTY RATE BASE AVERAGE COST | MILLS/KWH | R | 4 | PARTY YEAR ! GAME |
| PRBTV | PARTY RATE BASE TERMINAL VALUE | $MM | I | 4 | PARTY GAME |
| PRCC | PARTY REAL COST OF CAPITAL | FRACTION | R | 0 | PARTY |
| PRFIL | PROFILE CONTROL ON | T/F | L | 0 | |
| PRJGR | PTR: PROJECT GIVEN GRES | INDEX | I | 1 | GRES |
| PRJNA | GENERATING PROJECT NAME | NAME | A | 0 | PROJ |
| PRNAM | NAMES OF POWER RATES | NAME | A | 0 | PRATE |
| PRTGL | PTR: POWER RATE GIVEN GLOB LOAD | INDEX | I | 1 | GLOAD |
| PRTYT | PARTY RISK T | MW | R | 3 | PARTY MONTH YEAR ! GAME |
| PSAER | PUMPED STORAGE ABS ERROR | MW | R | 4 | GAME |
| PSGR | PTR: GLOB STORAGE GIVEN GLOB RES | INDEX | I | 1 | GRES |
| PSHMV | PUMPED STORAGE HOURLY MARG VALUE | MILLS/KWH | R | 3 | PSTORG HOUR DAY MONTH ! YEAR GAME |
| PSHNW | PUMPED STORAGE HOURLY NET GENER | AVG. MW | I | 3 | PSTORG HOUR ! DAY MONTH YEAR GAME |
| PSHSL | PUMPED STORAGE HOURLY SLOPE | MW/MILL/KWH | R | 3 | PSTORG HOUR ! DAY MONTH YEAR GAME |
| PSHST | PUMPED HOURLY END STORAGE | AVG. MW | I | 3 | PSTORG HOUR ! DAY MONTH YEAR GAME |
| PSHTS | PUMPED STORAGE HOURLY TOTAL SLPE | MW/MILL/KWH | R | 3 | PSTORG HOUR ! DAY MONTH YEAR GAME |
| PSIEC | PUMPED INITIAL ENERGY CONTENT | FRACTION | R | 0 | PARTY |
| PSMAX | HYDRO STORAGE MAXIMUM | MWH | I | 3 | PSTORG MONTH YEAR ! GAME |
| PSMER | PUMPED STORAGE MAX ERROR | MW | R | 4 | GAME |
| PSMP | COMMITTED PATH SHARE GIVEN MP | FRACTION | R | 3 | LPATH MPATH MONTH YEAR ! GAME |
| PSMPR | COMMITTED PATH SHARE GIVEN MP(R) | FRACTION | R | 3 | LPATH MPATH MONTH YEAR ! GAME |
| PSMXS | PUMPED STORAGE MAX STEP SIZE | MILLS/KWH | R | 0 | |
| PSNAM | PUMPED STORAGE NAME | NAME | A | 0 | PSTORG |
| PSNOD | PTR: PUMPED STORAGE GIVEN NODE | INDEX | I | 1 | NODE NPSTOR |
| PSRLX | PUMPED STORAGE RELAXATION COEFF | | R | 0 | |
| PSSCR | PUMPED STORAGE/CAPACITY RATIO | HOURS | R | 0 | PARTY |
| PSTPR | PRT: PUMPED STORAG GIVEN PTY,REG | INDEX | I | 1 | PARTY REGION |
| PTCAP | PATH "TO" CAPACITY | MW | I | 3 | PATH MONTH YEAR |
| PTCCP | PARTY CONTRACT CAPACITY | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTCFE | PARTY CONTRACT FIRM ENERGY | MW | I | 3 | PARTY YEAR ! GAME |
| PTCFL | PARTY CONTRACT FIRM LOAD | MW | I | 3 | PARTY YEAR ! GAME |
| PTCLM | PARTY CAP LOSS MULTIPLIER | MW2/MW2 | R | 0 | PARTY |
| PTCPD | PARTY CONTRACT PEAK DEMAND | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTDCL | PARTY THRML DERATE CAPACITY LOSS | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTDFL | PARTY DIRECT FIRM LOAD | MW | I | 3 | PARTY YEAR ! GAME |
| PTFPL | PARTY FIRM PEAK LOAD | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTGCP | PARTY GENERATING CAPACITY | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTGFE | PARTY GENERATING FIRM ENERGY | MW | I | 3 | PARTY YEAR ! GAME |
| PTHMP | PATH INDEX FOR LPATH, MPATH | INDEX | I | 2 | LPATH MPATH |
| PTMON | PATH APPLIES TO CURRENT MONTH | T/F | L | 2 | PATH MONTH YEAR |
| PTMCL | PARTY MAINTENANCE CAPACITY LOSS | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTMXE | PARTY MAX RISK ERROR | DAYS/YR | R | 0 | |
| PTPL | PARTY NO.LIST GIVEN POOL NO. | INDEX | I | 1 | PLPTY POOL |
| PTPLP | PARTY GIVEN PTHLNK, PATH | INDEX | I | 2 | PTHLNK PATH |
| PTRLX | PARTY RISK RELAXATION COEFF | $/D/D | R | 0 | PARTY |
| PTRSK | PARTY MONTHLY RISK | DAYS/YR | R | 3 | PARTY MONTH YEAR ! GAME |
| PTSFE | PARTY SURPLUS FIRM ENERGY | MW | I | 3 | PARTY YEAR ! GAME |
| PTSNS | PARTY STD DEV NET SURPLUS | MW | R | 3 | PARTY MONTH YEAR ! GAME |
| PTSPR | PARTY SPIN RESERVE REQUIREMENT | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTUCL | PARTY MEAN CAPACITY LOSS | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTUNS | PARTY MEAN NET SURPLUS | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTUPL | PARTY MEAN PEAK LOAD | MW | I | 3 | PARTY MONTH YEAR ! GAME |
| PTVCL | PARTY VARIANCE CAPACITY LOSS | MW**2 | R | 3 | PARTY MONTH YEAR ! GAME |
| PTVPL | PARTY VARIANCE PEAK LOAD | MW**2 | R | 3 | PARTY MONTH YEAR ! GAME |
| PTYGL | PTR: PARTY GIVEN GLOBAL LOAD | INDEX | I | 1 | GLOAD |

| | | | | | |
|---|---|---|---|---|---|
| PTYGR | PTR: PARTY GIVEN GLOBAL RESOURCE | INDEX | I | 1 | GRES |
| PTYGT | PTR: PARTY GIVEN GLOBAL TRANS | INDEX | I | 1 | GTRANS |
| PTYHY | PTR: PARTY GIVEN HYDRO | INDEX | I | 1 | HYDRO |
| PTYLG | PARTY NAME GIVEN PTHLNK.PATH | NAME | A | 0 | PTHLNK PATH |
| PTYND | PTR: PARTY GIVEN NODE | INDEX | I | 1 | NODE |
| PTYPS | PTR: PARTY GIVEN PUMPED STORAGE | INDEX | I | 1 | PSTORG |
| PTYPW | PTR: PARTY GIVEN POWER RATE | INDEX | I | 1 | PRATE |
| PUS | PATH COMMITTED USE | MW | I | 3 | PATH MONTH YEAR ! GAME |
| PYOCS | PARTY YEARLY OTHER COST | $MM/YR | I | 0 | PARTY DYEAR |
| PYORV | PARTY YEARLY OTHER REVENUE | $MM/YR | I | 0 | PARTY DYEAR |
| PYRBC | PARTY YEAR RATE BASE COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRBL | PARTY YEAR RATE BASE LOAD | AVG. MW | I | 4 | PARTY YEAR ! GAME |
| PYRBR | PARTY YEAR RATE BASE REVENUE | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRCC | PARTY YEAR CAPITAL COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYREL | PARTY YEAR EXPORT LOAD | AVG. MW | I | 4 | PARTY YEAR ! GAME |
| PYRER | PARTY YEAR EXPORT REVENUE | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRFC | PARTY YEAR FIXED COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRGN | PARTY YEAR RESOURCE GENERATION | AVG. MW | I | 4 | PARTY YEAR ! GAME |
| PYRIC | PARTY YEAR IMPORT COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRNC | PARTY YEAR NET COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRNL | PARTY YEAR NATIVE LOAD | AVG. MW | I | 4 | PARTY YEAR ! GAME |
| PYROC | PARTY YEAR OPERATING COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRPP | PARTY YEAR PURCHASED POWER | AVG. MW | I | 4 | PARTY YEAR ! GAME |
| PYRTC | PARTY YEAR TRANSMISSION COST | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| PYRTR | PARTY YEAR TRANSMISSION REVENUE | $MM/YR | I | 4 | PARTY YEAR ! GAME |
| RADMN | RESOURCE ADDITION MONTH | MNAME | A | 0 | ADDNO |
| RADMW | RESOURCE ADDITION CAPACITY | MW | I | 0 | ADDNO |
| RADPJ | RESOURCE ADDITION PROJECT NAME | NAME | A | 0 | ADDNO |
| RADPT | RESOURCE ADDITION PARTY | NAME | A | 0 | ADDNO |
| RADRG | RESOURCE ADDITION REGION | NAME | A | 0 | ADDNO |
| RADYR | RESOURCE ADDITION YEAR | YEAR | I | 0 | ADDNO |
| RAFER | RESOURCE ANNUAL FRM ENERGY RATIO | MWH/KW-YR | R | 2 | NEWRES |
| RAFUL | 1ST YR RANDOM ANNUAL FUEL PRICE | YEAR | I | 0 | |
| RALOD | 1ST YR RANDOM ANNUAL LOAD | YEAR | I | 0 | |
| RAQSL | RESOURCE AQUISITION SLOPE | MW/MILL | R | 0 | PARTY |
| RATEY | POWER RATE FOR YEAR | MILLS/KWH | R | 3 | PRATE YEAR ! GAME |
| RCALD | RECREATIONAL DEF ALLOWANCE(DATA) | FRACTION | R | 0 | WATER DMONTH PARTY |
| RCEPN | RECREATIONAL EV DEFICIT PENALTY | $MM/YR | R | 3 | HYDRO |
| RCESC | RES CAPITAL COST ESCALATION | RATIO | R | 2 | YEAR RESRC |
| RCESR | RES CAPITAL COST REAL ESCALATION | RATE/YR | R | 0 | DYEAR RESRC |
| RCGPN | RECREATIONAL GAM DEFICIT PENALTY | $MM/YR | R | 3 | HYDRO GAME |
| RCMPN | RECREATIONAL MON DEFICIT PENALTY | $MM/YR | R | 3 | HYDRO MONTH ! YEAR GAME |
| RCNTF | RESOURCE WEEKLY COMMITMENT FRAC | FRACTION | R | 3 | GRES WEEK MONTH YEAR ! GAME |
| RCSLD | RECREATIONAL DEF PEN SLOPE(D) | MILLS/FR | R | 0 | DMONTH PARTY |
| RCYPN | RECREATIONAL YR DEFICIT PENALTY | $MM/YR | R | 3 | HYDRO YEAR ! GAME |
| RDCND | PTR: REMOTE DEM CONTR GIVEN NODE | INDEX | I | 1 | NODE |
| RDLOD | 1ST YR RANDOM DAILY LOAD | YEAR | I | 0 | |
| RDRAT | DRATE FOR HEAD/THRML EFFECTS | FRACTION | R | 0 | DMONTH RESRC PARTY |
| RECAL | RECREATIONAL OEF ALLOWANCE(DATA) | FRACTION | R | 3 | HYDRO MONTH YEAR ! GAME |
| RECDF | RECREATIONAL DEFICIT FRACTION | FRACTION | R | 3 | HYDRO MONTH ! YEAR GAME |
| RECMV | RECREATIONAL MARGINAL VALUE | MILLS/KWH | R | 3 | HYDRO MONTH ! YEAR GAME |
| RECSL | RECREATIONAL OEF PENALTY SLOPE | MILLS/FR | R | 3 | HYDRO MONTH YEAR |
| REGGL | PTR: REGION GIVEN GLOBAL LOAD | INDEX | I | 1 | GLOAD |
| REGGR | PTR: REGION GIVEN GLOBAL RES | INDEX | I | 1 | GRES |
| REGLD | REGION OF LOAD FOR A PARTY | NAME | A | 0 | LOAD PARTY |
| REGND | PTR: REGION GIVEN NODE | INDEX | I | 1 | NODE |
| RELXC | RELAXATION COEFF ON NEW CAPACITY | 1/$MM | R | 0 | |
| RELXG | RELAXATION COEFF ON GTRANS PRICE | | R | 0 | |
| RELXT | RELAXATION COEFF ON TRANSMISSION | | R | 0 | |
| REMND | REMOTE REGION NODE | T/F | L | 2 | NODE |
| RESAQ | RESOURCE ACQUISITIONS BY MODEL | T/F | L | 0 | |
| RESAV | RESOURCE INSTALLED OR COMMITTED | T/F | L | 0 | RESRC PARTY REGION |
| RESCA | RESOURCE AVAILABLE FOR OPERATION | MW | I | 3 | GRES ! DAY MONTH YEAR GAME |
| RESCP | GENERIC RESOURCE CAPACITY | MW | I | 3 | GRES MONTH YEAR ! GAME |
| RESFE | GENERIC RESOURCE FIRM ENERGY | AMW | I | 3 | GRES MONTH YEAR ! GAME |
| RESGR | PTR: RESOURCE GIVEN GLOBAL RES | INDEX | I | 1 | GRES |
| RESMC | RESOURCE MARGINAL COST | MILLS/KWH | R | 3 | GRES MONTH YEAR ! GAME |
| RESMV | RESOURCE MARGINAL VALUE | MILLS/KWH | R | 3 | GRES ! HOUR DAY MONTH YEAR GAME |
| RESMW | NAMEPLATE INITIAL CAPACITY | MW | I | 0 | RESRC PARTY REGION |
| RESPJ | RESOURCE TYPES FOR PROJECT | NAME | A | 0 | PROJ |
| RFEFR | RESOURCE FIRM ENERGY FRACTION | FRACTION | R | 2 | GRES |
| RFRLK | PTR: "FROM" REGION GIVEN LINK | INDEX | I | 1 | LINK |
| RGDFU | REGION DAILY FUEL USE | FU/YR | I | 3 | FUEL REGION DAY ! MONTH YEAR GAME |
| RGFER | REGION FUEL LIMIT ERROR | FUEL UNITS | I | 3 | FUEL MONTH YEAR ! GAME |
| RGFSP | REGION FUEL SHADOW PRICE | $/FUEL UNIT | R | 3 | FUEL MONTH YEAR ! GAME |
| RGHFU | REGION HOURLY FUEL USE | FU/YR | I | 3 | FUEL REGION HOUR ! DAY MONTH YEAR GAME |
| RGMFU | REGION MONTHLY FUEL USE | FU/YR | I | 3 | FUEL REGION MONTH ! YEAR GAME |
| RGNHY | PTR: REGION GIVEN HYDRO | INDEX | I | 1 | HYDRO |
| RGRNR | PTR: REGION GIVEN REGION NEWRES | INDEX | I | 1 | REGNR |
| RGYFU | REGION YEARLY FUEL USE | FU/YR | I | 3 | FUEL REGION YEAR ! GAME |
| RJPRC | RETURN REJECTION PRICE | MILLS/KWH | R | 0 | CONTR CONADJ |
| RLFUL | 1ST YR RANDOM LT FUEL PRICE | YEAR | I | 0 | |
| RLLOD | 1ST YR RANDOM LONG-TERM LOAD | YEAR | I | 0 | |
| RMMOS | RES MONTHLY MAINT OUT SHAPE | FRACTION | R | 0 | DMONTH RESRC PARTY |
| RNAME | NAMES OF REGIONS | NAME | A | 0 | REGION |
| RNMTF | RESOURCE NOT ON MAINTENANCE FRAC | FRACTION | R | 3 | GRES MONTH YEAR ! GAME |
| RNRNA | REGION NEW RESOURCE NAME | NAME | A | 0 | REGNR |
| RNRNR | PTR: REGION NEWRES GIVEN NEWRES | INDEX | I | 1 | NEWRES |
| ROPRF | RESOURCE HOURLY OPERATION FRAC | FRACTION | R | 3 | GRES HOUR ! DAY MONTH YEAR GAME |
| RPLAV | 1ST YR RANDOM DAILY PLANT AVAIL | YEAR | I | 0 | |
| RPRLX | RESMCC RELAXATION COEF | FRACTION | R | 0 | |
| RSCHD | CONTRACT RATE SCHEDULE | NAME | A | 0 | CONTR CONADJ |
| RSCPC | RESOURCE COMMITTED CAPACITY | MW | I | 2 | GRES MONTH YEAR |
| RSDAF | RESOURCE DAILY AVAIL. FRACTION | FRACTION | R | 3 | GRES DAY ! MONTH YEAR GAME |
| RSDCS | RESOURCE DAILY COST | $MM/YR | I | 3 | GRES DAY ! MONTH YEAR GAME |
| RSDEM | RESOURCE DAILY EMISSIONS | EM/YR | I | 3 | EMISON GRES DAY ! MONTH YEAR GAME |
| RSDMB | RESOURCE DAILY MARG. BENEFIT | $/KW-YR | R | 3 | GRES DAY MONTH YEAR ! GAME |
| RSDMW | RESOURCE DAILY PRODUCTION | AVG. MW | I | 3 | GRES DAY ! MONTH YEAR GAME |
| RSHCS | RESOURCE HOURLY COST | $MM/YR | I | 3 | GRES HOUR ! DAY MONTH YEAR GAME |
| RSHEM | RESOURCE HOURLY EMISSIONS | EM/YR | I | 3 | EMISON GRES HOUR ! DAY MONTH YEAR GAME |
| RSHMB | RESOURCE HOURLY MARG. BENEFIT | $/KW-YR | R | 3 | GRES HOUR ! DAY MONTH YEAR GAME |
| RSHMW | RESOURCE HOURLY GENERATION | AVG. MW | I | 3 | GRES HOUR ! DAY MONTH YEAR GAME |
| RSMCS | RESOURCE MONTHLY COST | $MM/YR | I | 3 | GRES MONTH ! YEAR GAME |
| RSMEM | RESOURCE MONTHLY EMISSIONS | EM/YR | I | 3 | EMISON GRES MONTH ! YEAR GAME |
| RSMMB | RESOURCE MONTHLY MARG. BENEFIT | $/KW-YR | R | 3 | GRES MONTH YEAR ! GAME |

| | | | | | |
|---|---|---|---|---|---|
| RSMMW | RESOURCE MONTHLY PRODUCTION | AVG. MW | I | 3 | GRES MONTH ! YEAR GAME |
| RSNAM | NAMES OF RESOURCES | NAME | A | 0 | RESRC |
| RSRNR | PTR: RESOURC GIVEN REGION NEWRES | INDEX | I | 1 | REGNR |
| RSTRT | ITERATION RESTART | T/F | L | 0 | |
| RSWMB | RESOURCE WEEKLY MARG. BENEFIT | $/KW-YR | R | 3 | GRES WEEK MONTH YEAR ! GAME |
| RSYCC | RESOURCE YEARLY CAPITAL COST | $MM/YR | I | 3 | GRES YEAR ! GAME |
| RSYCS | RESOURCE YEARLY COST | $MM/YR | I | 3 | GRES YEAR ! GAME |
| RSYEM | RESOURCE YEARLY EMISSIONS | EM/YR | I | 3 | EMISON GRES YEAR ! GAME |
| RSYFC | RESOURCE YEARLY FIXED COST | $MM/YR | I | 3 | GRES YEAR ! GAME |
| RSYMB | RESOURCE YEARLY MARG. BENEFIT | $/KW-YR | R | 3 | GRES YEAR ! GAME |
| RSYMW | RESOURCE YEARLY PRODUCTION | AVG. MW | I | 3 | GRES YEAR ! GAME |
| RTLCK | PTR: RETURN LINK GIVEN CONTRACT | INDEX | I | 1 | CONTR |
| RTOLK | PTR: "TO" REGION GIVEN LINK | INDEX | I | 1 | LINK |
| RTRAT | RETURN RATE | FRACTION | R | 0 | CONTR CONADJ |
| RTTYP | RATE TYPE FOR LINK | NAME | A | 2 | LINK |
| RUNDY | RUN SPECIFIC DAYS | T/F | L | 0 | DAY |
| RUNHR | RUN SPECIFIC HOURS | T/F | L | 0 | HOUR |
| RUNMN | RUN SPECIFIC MONTHS | T/F | L | 0 | MONTH |
| RUNYR | RUN SPECIFIC YEARS | T/F | L | 0 | DYEAR |
| RVESC | RES VARIABLE COST ESCALATION | RATIO | R | 2 | YEAR RESRC |
| RVESR | VARIABLE O&M REAL ESCALATION | RATE/YR | R | 0 | DYEAR RESRC |
| RWATM | 1ST DATA MONTH FOR RANDOM WATER | INDEX | I | 2 | |
| RWATY | 1ST YR RANDOM WATER | YEAR | I | 0 | |
| RWTMD | 1ST MONTH RANDOM WATER | DMONTH | A | 0 | |
| S2PMW | VARIANCE PER MW OF CAPACITY | MW | R | 2 | GRES |
| SBGMN | SUPPLEMENTAL ENERGY BEGIN MONTH | DMONTH | A | 0 | CONTR CONADJ |
| SD01G | 1 YR ECONOMIC GROWTH STD DEV | FRACTION | R | 0 | |
| SD01L | 1 YR CONDNL. LOAD GROWTH STD DEV | FRACTION | R | 0 | LOAD PARTY |
| SD01O | 1 YR STD. DEVIATION OF OIL PRICE | FRACTION | R | 0 | |
| SD01R | 1 YR REGION ECON. GROWTH STD DEV | FRACTION | R | 0 | REGION |
| SD20G | 20 YR ECONOMIC GROWTH STD DEV | FRACTION | R | 0 | |
| SD20L | 20 YR CONDNL LOAD GROWTH STD DEV | FRACTION | R | 0 | LOAD PARTY |
| SD20O | 20 YR STD DEVIATION OF OIL PRICE | FRACTION | R | 0 | |
| SD20R | 20 YR REGION ECON GROWTH STD DEV | FRACTION | R | 0 | REGION |
| SENMN | SUPPLEMENTAL ENERGY END MONTH | DMONTH | A | 0 | CONTR CONADJ |
| SHMAN | SHAPE FIXED MAINT (IF LCMAN=T) | T/F | L | 0 | |
| SHRS | SUPPLEMENTAL HOURS PER YEAR | HOURS | I | 2 | CONTR YEAR |
| SLHMW | STORAGE LOAD HOURLY RECHARGE | AVG. MW | I | 3 | PSTORG HOUR ! DAY MONTH YEAR GAME |
| SLSLP | STORAGE LOAD SENSITIVITY | MILLS/KWH | R | 0 | |
| SMDWM | SAME MODEL AND DATA DAY.WEEK.MON | T/F | L | 0 | |
| SMHRS | SUPPLEMENTAL HOURS PER MONTH | HOURS | I | 2 | CONTR MONTH YEAR |
| SNAME | STUDY NAME OF PMDAM MODEL RUN | NAME | A | 0 | |
| SNINF | SENSIT.HYD PRICE TO INFLOW ERR | MILLS/FR | R | 3 | REGION MONTH YEAR ! GAME |
| SNSPK | SENSIT.HYD PRICE TO SNOPACK ERR | MILLS/FR | R | 3 | SPRECN MONTH YEAR ! GAME |
| SPMES | AVG. SNOPACK MONTHLY ENERGY SHAP | FRACTION | R | 0 | SPREGN DMONTH |
| SPRFR | SPINNING RESERVE FRACTION | FRACTION | R | 0 | RESRC PARTY |
| SPRNA | NAMES OF SNOWPACK REGIONS | NAME | A | 0 | SPREGN |
| STEFF | STORAGE CYCLE EFFICIENCY | FRACTION | R | 0 | PARTY |
| STITL | STUDY TITLE OF PMDAM MODEL RUN | NAME | A | 0 | WORD |
| STMAX | MAX STEP SIZE MULTIPLIER | FRACTION | R | 0 | |
| STMIN | MIN STEP SIZE MULTIPLIER | FRACTION | R | 0 | |
| STMLT | STEP SIZE MULTIPLIER | FRACTION | R | 2 | |
| STNAM | STRANS NAME | NAME | A | 0 | STRANS |
| STPLP | STRANS GIVEN PTHLNK. TPATH | INDEX | I | 2 | PTHLNK PATH |
| STRAT | STRATEGY NUMBER FOR RUN | INTEGER | I | 0 | |
| STRCN | STRATEGY LIST GIVEN CONTRACT | INTEGER | I | 0 | CONTR |
| STRYR | FIRST CAL YEAR OF MODEL | YEAR | I | 0 | |
| SUPAD | SUPPLY CURVE CUMULATIVE MW | MW | I | 3 | REGNR YEAR ! GAME |
| SUPCC | OVERNIGHT CAPITAL COST CURVE | $/KW | I | 0 | RESRC REGION LEVEL |
| SUPEN | SUPPLEMENTAL ENERGY RATIO | KWH/KW | I | 0 | CONTR CONADJ |
| SUPMC | SUPPLY CURVE MARGINAL COST | $/KW | R | 3 | REGNR YEAR ! GAME |
| SUPMP | SUPPLY CURVE MARGINAL PRICE | $/KW | R | 3 | NEWRES YEAR ! GAME |
| SUPMW | NEW CAPACITY SUPPLY CURVE MW | MW | I | 0 | RESRC REGION LEVEL |
| SUPPR | SUPPLEMENTAL ENERGY PRICE | %COST | I | 0 | CONTR CONADJ |
| TADMN | MONTH OF TRANS ADDTION | MONTH | A | 0 | ADDNO |
| TADPT | OWNER OF TRANS ADDITION | NAME | A | 0 | ADDNO |
| TADTR | TRANSMISSION LINK ADDED | NAME | A | 0 | ADDNO |
| TADYR | YEAR OF TRANS ADDTION | YEAR | I | 0 | ADDNO |
| TCESC | TRANS CAPITAL ESCALATION | RATIO | R | 2 | YEAR |
| TCESR | TRANS CAP COST REAL ESC RATE | RATE/YR | R | 0 | DYEAR |
| TEMDY | TRANS EFF MAX ABS DAILY ERROR | FRACTION | R | 3 | TRANS DAY ! MONTH YEAR GAME |
| TEMGM | TRANS EFF MAX ABS GAME ERROR | FRACTION | R | 3 | TRANS GAME |
| TEMMN | TRANS EFF MAX ABS MONTH ERROR | FRACTION | R | 3 | TRANS MONTH ! YEAR GAME |
| TEMYR | TRANS EFF MAX ABS YEARLY ERROR | FRACTION | R | 3 | TRANS YEAR ! GAME |
| TERDY | TRANS EFF AVG ABS DAILY ERROR | FRACTION | R | 3 | TRANS DAY ! MONTH YEAR GAME |
| TERGM | TRANS EFF AVG ABS GAME ERROR | FRACTION | R | 3 | TRANS GAME |
| TERHR | TRANS EFF HOURLY ERROR | FRACTION | R | 3 | TRANS HOUR ! DAY MONTH YEAR GAME |
| TERMN | TRANS EFF AVG ABS MONTH ERROR | FRACTION | R | 3 | TRANS MONTH ! YEAR GAME |
| TERYR | TRANS EFF AVG ABS YEARLY ERROR | FRACTION | R | 3 | TRANS YEAR ! GAME |
| TFCAP | TRANS "FROM" CAPACITY | MW | I | 3 | TRANS MONTH YEAR |
| TFCPC | TRANMISSION FROM CAPAC COMMITED | MW | I | 2 | GTRANS MONTH YEAR |
| TFINL | TRANSMISSION FINANCIAL LIFE | YEARS | I | 0 | |
| TFRPD | TRANSMISSION "FROM" POD | NAME | A | 0 | TRANS |
| THE | EV TOTAL HYDRO ERROR | GWH | R | 4 | HYDRO |
| THMWF | HOURLY TRANSMISSION(FORWARD) | AVG. MW | I | 3 | GTRANS HOUR ! DAY MONTH YEAR GAME |
| THMWR | HOURLY TRANSMISSION(REVERSE) | AVG. MW | I | 3 | GTRANS HOUR ! DAY MONTH YEAR GAME |
| TIMAX | TOTAL ITERATIONS FOR STMAX | COUNTER | I | 0 | |
| TIME | TIME OF PMDAM MODEL RUN | NAME | A | 0 | TIME |
| TIMIN | TOTAL ITERATIONS FOR STMIN | COUNTER | I | 0 | |
| TLOS0 | TRANSMISSION LOSS RATE @ 0% LD | FRACTION | R | 0 | TRANS |
| TLOS1 | TRANSMISSION LOSS RATE @100% LD | FRACTION | R | 0 | TRANS |
| TMMB | "TO" METAPATH MARG. BENEF | $/KW-YR | R | 3 | MPATH MONTH YEAR ! GAME |
| TNAME | NAMES OF TRANSMISSION LINKS | NAME | A | 0 | TRANS |
| TOCAP | "TO" CAPACITY | MW | I | 0 | ADDNO |
| TOESC | TRANS OPERATION COST ESCALATION | RATIO | R | 2 | YEAR |
| TOESR | TRANS OPER COST REAL ESC RATE | RATE/YR | R | 0 | DYEAR |
| TOLVL | TOPTY CONTRACT LEVELIZATION FACT | FRACTION | R | 2 | NEWCON YEAR |
| TOPCN | PTR: "TO" PARTY GIVEN CONTR | INDEX | I | 1 | CONTR |
| TOPEF | TPATH TO EFFIC. | FRACTION | R | 3 | TPATH ! HOUR DAY MONTH YEAR GAME |
| TOPLK | PTR: "TO" PARTY GIVEN LINK | INDEX | I | 1 | LINK |
| TOPTY | "TO" CONTRACT PARTY | NAME | A | 0 | CONTR |
| TOREG | "TO" CONTRACT REGION | NAME | A | 0 | CONTR |
| TOTIT | TOTAL (CUM) OUTER ITERATION | COUNTER | I | 2 | |
| TPDPA | TO END POD FOR PATH | NAME | A | 0 | PATH |
| TPMB | "TO" PATH MARG. BENEFIT | $/KW-YR | R | 3 | PATH MONTH YEAR ! GAME |

| | | | | | |
|---|---|---|---|---|---|
| TPNAM | TPATH NAME | NAME | A | 0 | TPATH |
| TPPTH | TPATH GIVEN PATH | INDEX | I | 2 | PATH |
| TPTOM | TPATH APPLIES TO CURRENT MONTH | T/F | L | 2 | TPATH MONTH YEAR |
| TRATE | TRANSMISSION RATE | MILLS/KWH | R | 3 | GTRANS YEAR ! GAME |
| TRAVL | TRANSMISSION POSSIBLE | T/F | L | 0 | TRANS PARTY |
| TRDMW | TRANSMISSION DAILY FLOW | AVG. MW | I | 3 | GTRANS DAY ! MONTH YEAR GAME |
| TRDOL | TRANSMISSSION CAPITAL SPENDING | $MM/YR | I | 2 | GTRANS YEAR |
| TRDRV | TRANSMISSSION DAILY REVENUE | $MM/YR | I | 3 | GTRANS DAY ! MONTH YEAR GAME |
| TREFF | TRANSMISSION EFFICIENCY | FRACTION | R | 3 | TRANS HOUR DAY MONTH ! YEAR GAME |
| TRFCP | TRANSMISSION FROM CAPACITY | MW | I | 3 | GTRANS MONTH YEAR |
| TRHMW | NET HOURLY TRANSMISSION | AVG. MW | I | 3 | GTRANS HOUR ! DAY MONTH YEAR GAME |
| TRHRV | HOURLY TRANSMISSION REVENUE | $MM/YR | I | 3 | GTRANS HOUR ! DAY MONTH YEAR GAME |
| TRMMW | TRANSMISSION MONTHLY FLOW | AVG. MW | I | 3 | GTRANS MONTH ! YEAR GAME |
| TRMRV | TRANSMISSION MONTHLY REVENUE | $MM/YR | I | 3 | GTRANS MONTH ! YEAR GAME |
| TRNMW | TRANS NET "FROM" MW | AVG. MW | I | 3 | TRANS ! HOUR DAY MONTH YEAR GAME |
| TRNCC | TRANSMISSION CAPITAL COST | $MM | I | 0 | ADDNO |
| TRNFC | ANNUAL OPERATING COST | $MM/YR | I | 0 | ADDNO |
| TRNGT | PTR: TRANS ACT GIVEN GLOB TRANS | INDEX | I | 1 | GTRANS |
| TRNLG | TRANS NAME GIVEN PTHLNK.PATH | NAME | A | 0 | PTHLNK PATH |
| TRPLP | TRANS GIVEN PTHLNK, TPATH | INDEX | I | 2 | PTHLNK TPATH |
| TRTCP | TRANSMISSION TO CAPACITY | MW | I | 3 | GTRANS MONTH YEAR |
| TRTTY | RATE TYPE FOR TRANSIMISSION | NAME | A | 0 | TRANS PARTY |
| TRYCC | TRANSMISSION YEARLY CAPITAL COST | $MM/YR | I | 3 | GRES YEAR |
| TRYFC | TRANSMISSION YEARLY FIXED COST | $MM/YR | I | 3 | GRES YEAR |
| TRYMW | TRANSMISSION YEARLY FLOW | AVG. MW | I | 3 | GTRANS YEAR ! GAME |
| TRYRV | TRANSMISSION YEARLY REVENUE | $MM/YR | I | 3 | GTRANS YEAR ! GAME |
| TTCAP | TRANS "TO" CAPACITY | MW | I | 3 | TRANS MONTH YEAR |
| TTCPC | TRANSMISSION TO CAPAC COMMITED | MW | I | 2 | GTRANS MONTH YEAR |
| TTOPD | TRANSMISSION "TO" POD | NAME | A | 0 | TRANS |
| TVMOV | TERMINAL MARGINAL OPER VALUE | $/MW | R | 2 | NEWRES |
| UFERG | UNDERFLOW ERROR GAME | AVG.MW | R | 4 | GAME |
| UFMXS | HYDRO UNDER MIN FLOW MAX STEP | MILLS/KWH | R | 0 | |
| UFRLX | HYDRO UNDER MIN FLOW RELAX COEF. | | R | 0 | |
| UPDTA | UPDATE OUTER ITER AQUIRE SHADOW PRICES | | L | 0 | |
| UPDTI | UPDATE INNER ITER SHADOW PRICES | | L | 0 | |
| UPDTO | UPDATE OUTER ITER OPERATION SHADOW PRICES | | L | 0 | |
| USIZE | TYP. UNIT NAMEPLATE CAPACITY | MW | I | 0 | RESRC PARTY |
| USSHR | UNIT SIZE SHARE FOR A PARTY | FRACTION | R | 0 | RESRC PARTY |
| VAROM | VARIABLE O&M RATE | MILLS/KWH | R | 0 | RESRC. |
| WCELD | DATA WEEK CONTRACT ENERGY LIMIT | RATIO | R | 0 | DMONTH CONTR CONADJ |
| WCELM | WEEK CONTRACT ENERGY LIMIT | RATIO | R | 2 | WKLMT MONTH YEAR |
| WCESP | WEST COAST EMISSION SHADOW PRICE | $/EU | R | 3 | EMISON YEAR ! GAME |
| WCMEM | WEST COAST MONTHLY EMISSIONS | EU/YEAR | I | 3 | EMISON MONTH YEAR ! GAME |
| WCYEM | WEST COAST YEARLY EMISSIONS | EU/YEAR | I | 3 | EMISON YEAR ! GAME |
| WCYET | WC YEARLY EMISSIONS TAXES | $MM/YEAR | I | 3 | EMISON YEAR ! GAME |
| WDDWD | MODEL WKDAY GIVEN DATA WKDAY | WKDAY | I | 0 | DWKDAY |
| WDDDD | WEEK DAY OF DATA DAY | INDEX | I | 0 | DDAY DMONTH YEAR |
| WDWGT | WEIGHT ON WKDAYS IN WEEK | RATIO | R | 1 | WKDAY |
| WEKVR | DUMMY WEEKLY VARIABLE(NOT USED) | XX | I | 4 | BOUND ! WEEK |
| WKODY | MODEL WEEK OF MODEL DAY | INDEX | I | 0 | DAY MONTH YEAR |
| WKWGT | WEIGHT ON WEEKS IN MONTH | RATIO | R | 1 | WEEK MONTH YEAR |
| WLMLK | PTR: WEEK LIMIT GIVEN LINK | INDEX | I | 1 | LINK |
| WLMMV | WEEK LIMIT MARGINAL VALUE | MILLS/KWH | R | 3 | WKLMT WEEK MONTH YEAR ! GAME |
| WLMNA | WEEK LIMIT NAME | NAME | A | 0 | WKLMT |
| WMODY | MODEL WEEK MONTH OF MODEL DAY | INDEX | I | 0 | DAY MONTH YEAR |
| WSELM | WEST COAST EMISSION LIMIT | EMIS UNITS | I | 0 | DYEAR EMISON |
| WSETX | WEST COAST EMISSION TAX | $/EU | R | 0 | DYEAR EMISON |
| WUPPR | MODEL WEEK UPPER LOOP LIMIT | INDEX | I | 0 | MONTH YEAR |
| WYODY | MODEL WEEK YEAR OF MODEL DAY | INDEX | I | 0 | DAY MONTH YEAR |
| XBGMN | EXCHANGE ENERGY BEGIN MONTH | DMONTH | A | 0 | CONTR CONADJ |
| XENMN | EXCHANGE ENERGY END MONTH | DMONTH | A | 0 | CONTR CONADJ |
| XGAME | LAST GAME WITH WARM START | COUNTER | I | 0 | |
| XHRS | EXCHANGE HOURS PER YEAR | HOURS | I | 2 | CONTR YEAR |
| XMHRS | EXCHANGE HOURS PER MONTH | HOURS | I | 2 | CONTR MONTH YEAR |
| YABHE | YEARLY TOTAL ABS HYDRO ERROR | GWH | R | 4 | HYDRO YEAR GAME |
| YHYMX | YEARLY TOTAL HYDRO MAX ENERGY | GWH | R | 4 | HYDRO YEAR GAME |
| YLMLK | PTR: YEAR LIMIT GIVEN LINK | INDEX | I | 1 | LINK |
| YLMMV | YEARLY LIMIT MARGINAL VALUE | MILLS/KWH | R | 3 | YRLMT YEAR ! GAME |
| YLMNA | YEAR LIMIT NAME | NAME | A | 0 | YRLMT |
| YRWKD | DAY GIVEN WKDAY, WEEK | INDEX | I | 0 | WKDAY WEEK MONTH YEAR |
| YTHE | YEARLY TOTAL HYDRO ERROR | GWH | R | 4 | HYDRO YEAR GAME |

# REFERENCES

# INDEX