Docket No. UE 991832
EXHIBIT NO. ________

OREGON

UE 111

PACIFICORP

February 1, 2000

ICNU DATA REQUEST
ATTACHMENT RESPONSE 1.70d

WUTC
DOCKET NO. UE-991832
EXHIBIT # ~~191~~ ~~T65~~ 191
ADMIT W/D REJECT

Attachment WA Staff 1.1c

PD/MAC

PacifiCorp's Production Cost Model
(for Macintosh)

September, 1999

Overview

- Why use PD/Mac
  - — Simulate power supply operation of the Company
  - — Calculate net power cost
- What the model does
  - — Produce normalized net power cost
- Net power cost accounts
  - — Account 447: Wholesale revenue, Firm and Non-firm
  - — Account 555: Purchased power expenses, Firm and Non-firm
  - — Account 565: Wheeling expenses
  - — Account 501: Fuel expenses
- Model logic
- Model structure
- Model limitations
- Model inputs
- Normalization
- Types of semi-annual studies
- Outputs
  - — Net power cost
  - — Hydro generation
  - — Thermal generation
  - — Non-firm sales and purchases

Description and Logic

The objective of PacifiCorp's production cost model, PD/Mac, is to simulate the operation of the power supply portion of PacifiCorp under a variety of streamflow and associated energy market conditions. The results obtained from the various streamflow conditions are averaged to produce a "normalized" measure of net power costs for use in the determination of Company's revenue requirement. The results of the production cost model are not intended to match actual costs on a year by year basis, but are intended to provide results which are fair and reasonable over the long term.

Figure 1 presents an overview of the PD/Mac computer logic. Figures 2 and 3 expand the production dispatch portion of the model. Figure 4 points at the complexity of the electrical system within which PacifiCorp operates. The fully expanded flow chart of the PD/Mac model including the Pacific Northwest interactions is presented and discussed in the following subsection of this model description.

The model accepts as input specific information regarding the Company's loads and resources. Inputs include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales data, firm wholesale purchase data, firm wheeling contract information, Pacific Northwest regional data, and nonfirm wholesale sales and purchase market data. The model then simulates the operation of PacifiCorp's system calculating a value for each variable that is dependent upon the availability of hydroelectric generation, for each month of the study period under each of 50 streamflow conditions. The water year dependent variables include:

- Interchange and storage transactions, performed under the Pacific Northwest Coordination Agreement.
- Thermal generation by plant required to meet firm and nonfirm loads.
- Nonfirm sale transactions within the Pacific Northwest and the markets of California, Nevada, and the Desert Southwest.
- Nonfirm purchase transactions, either to satisfy any deficits or to displace the most expensive thermal generation.
- Pacific and Regional storage and/or spill of any surplus energy.

The fifty values for each variable are averaged to produce a "normalized" result.

Normalization as used in reference to the production cost model is done in two ways. First, normalization is done so that the test year is representative of the conditions that are expected to exist. (This concept is similar to the "normal" weather patterns that are referenced in weather reports). The following are examples of this type of normalization adjustments made by the Company to adjust the input data for the production cost model:

1. The system load net of special sales is weather normalized; i.e., is adjusted to reflect loads that would have occurred under normal temperature conditions in the Company's service area. (The calculation is done outside of the model. The result is an input to PD/Mac).

2. The Company's thermal plant data is normalized by

making adjustments for major known and measurable changes that affect the output of the plant, such as turbine upgrades and scrubber additions. Fuel costs for each plant are based on the fuel costs incurred during the historical test period, adjusted for known and measurable changes for items such as specific coal related taxes and new or changed contracts. (The fuel cost calculation is done outside of the model. The result is an input to PD/Mac).

3. The availability of energy from Company-owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 50 different water years identified in the Hydro Regulation. The resultant 50 sets of thermal generation, nonfirm sales and purchases, and hydroelectric generation are then averaged using a weighting method which accounts for 11~~1~~5 years of streamflow data as measured on the Columbia River at The Dalles.

In any hydroelectric-oriented utility system, a major variable affecting power supply is river flow conditions. The operation of the thermal electric resources in the Pacific Northwest and adjacent regions is directly affected by streamflow conditions within the Pacific Northwest. During those periods when the streamflows are at their lowest, it is necessary for the utilities to increase operation of their thermal electric resources, resulting in higher operating expenses, primarily due to fuel costs. Under conditions of high stream flows, the excess hydroelectric production may be used to reduce the generation at the more expensive thermal electric plants, which in turn results in reduced operating expenses of some utilities and an increase in revenues of other utilities, or any combination thereof. Streamflow conditions also affect wholesale market interactions among western utilities. Use of a single streamflow condition does not adequately represent all the combinations of variables that are found in actual operating conditions. Therefore, the utilities and the regulatory commissions in the Pacific Northwest have adopted the use of the production cost analysis, which simulates the operation of the system using a set of historical streamflow conditions, and then averages the results to represent what can reasonably be expected to occur under so-called "normal" conditions. Actual test year production costs are then adjusted to reflect "normal" operating costs in the determination of revenue requirement.

Normalization is also the process of modifying the actual test year data by removing all known abnormalities and making adjustments for all known changes. These normalizations vary among the jurisdictions and are used to bring the Production Cost Model results into line with other areas of consideration such as Rate Base treatment or Construction Expense. Examples of this type of normalization are:

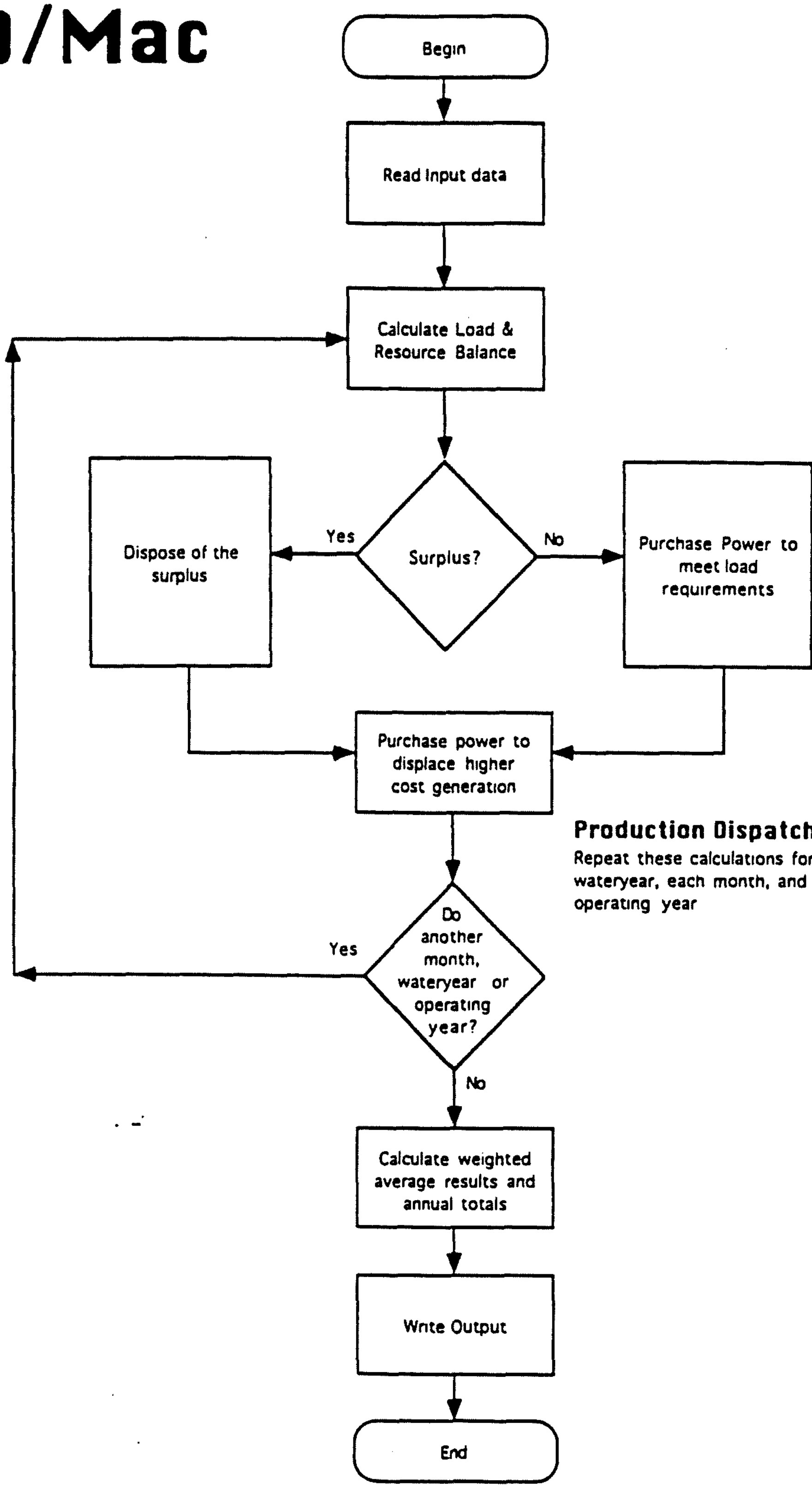
1. Firm wholesale power purchases and sales under long-term contracts with other utilities or qualifying facilities are normalized by making adjustments for changes in price and quantity.

2. Transmission availability is normalized by making adjustments for known changes to transmission paths such as the upgrades to the Pacific Northwest/Pacific Southwest Intertie and the completion of the Company's interconnection with Nevada Power Company.

Figure 1
Overview

Production Dispatch / Macintosh Version

PD/Mac

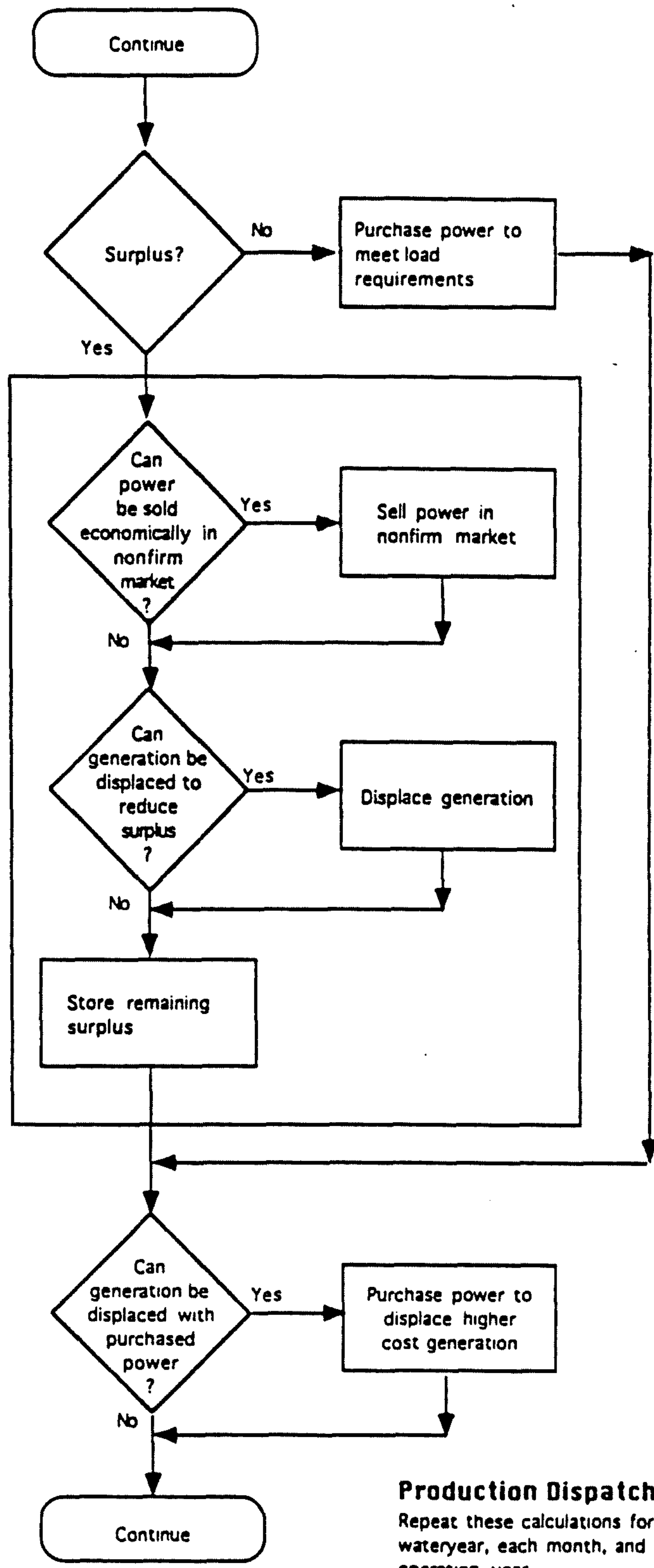


Production Dispatch
Repeat these calculations for for each wateryear, each month, and each operating year

Figure 2
One generator, One market

Production Dispatch / Macintosh Version

Surplus Disposition
(Simplified)

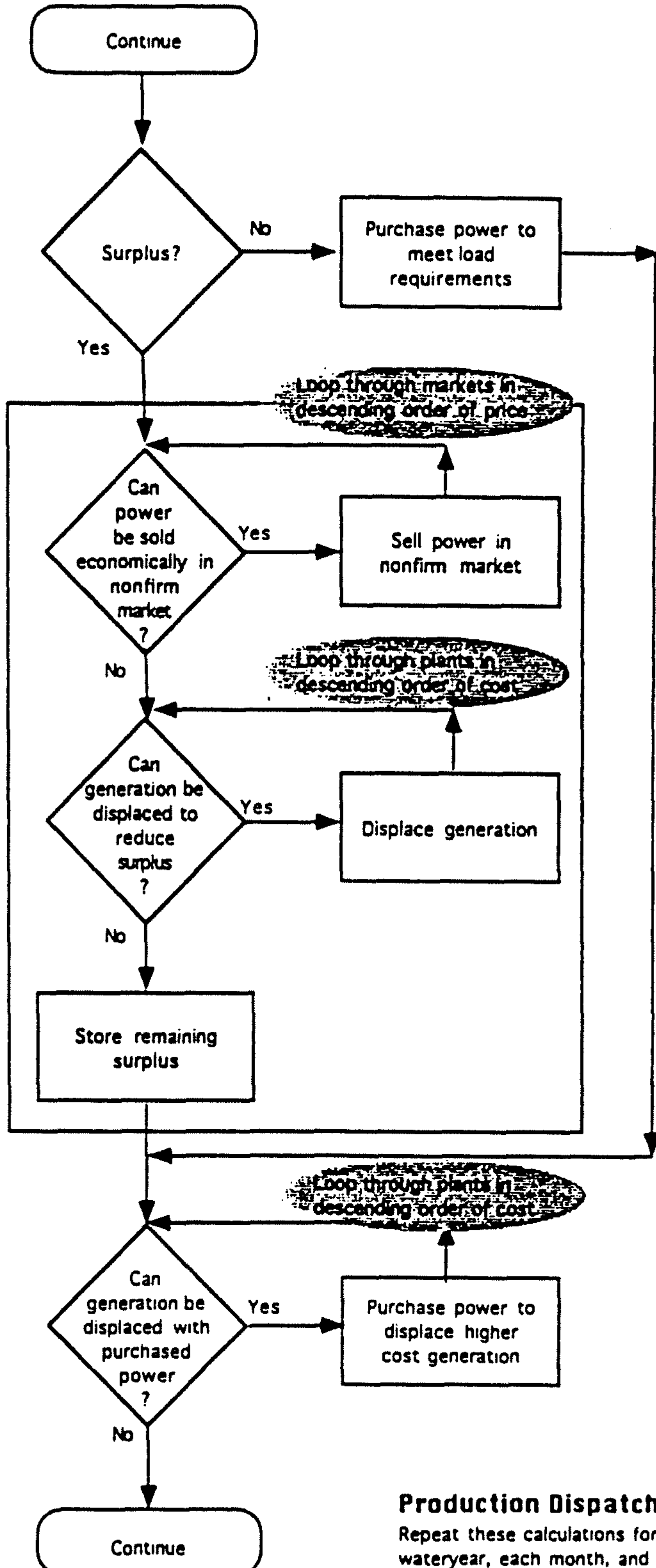


Production Dispatch
Repeat these calculations for for each wateryear, each month, and each operating year

Figure 3
Multi Resources & Markets

Production Dispatch / Macintosh Version

Surplus Disposition (Simplified)

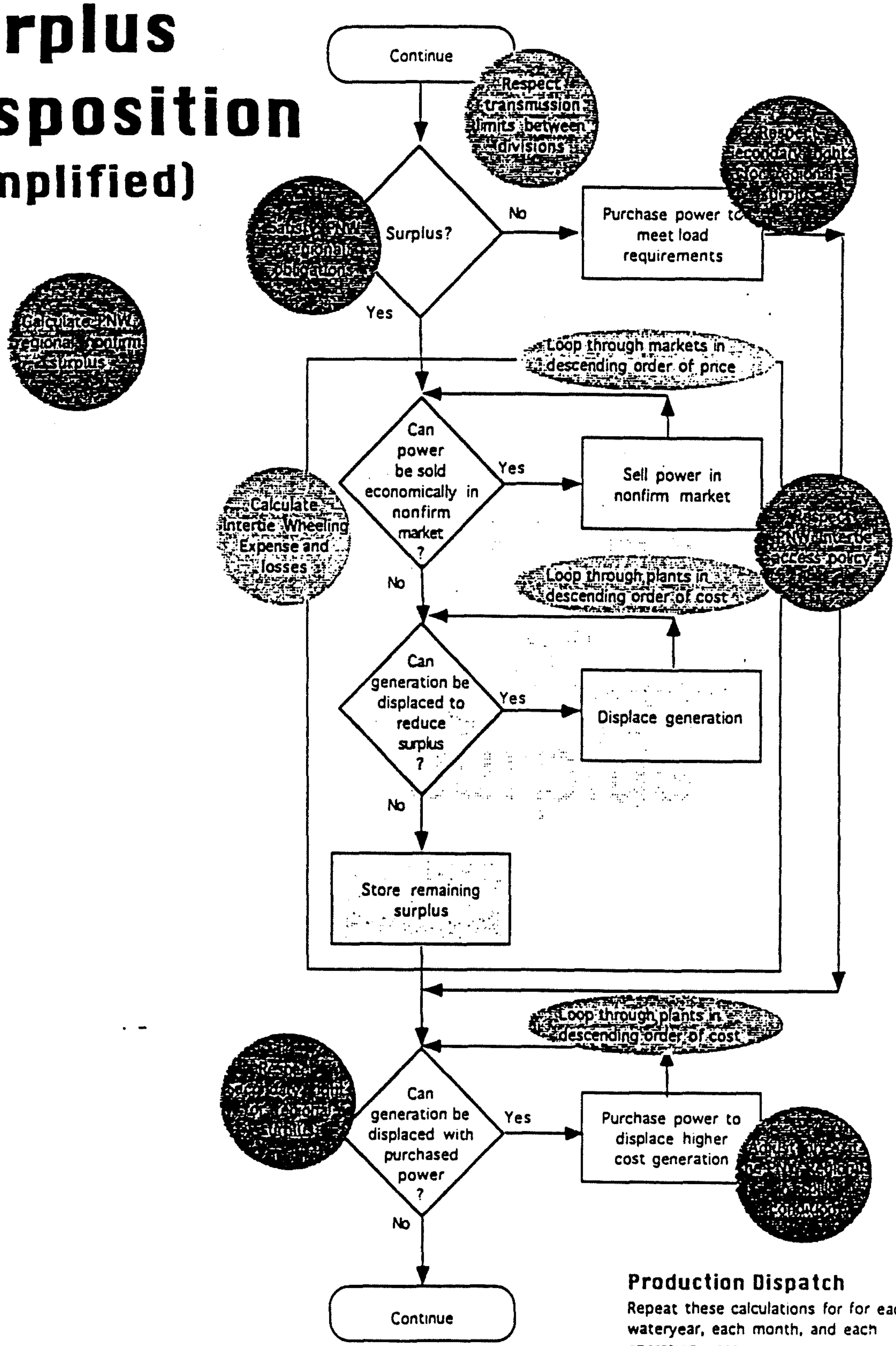


Production Dispatch
Repeat these calculations for for each wateryear, each month, and each operating year

Figure 4
Increasing Complexity

Production Dispatch / Macintosh Version

Surplus Disposition
(Simplified)



Production Dispatch
Repeat these calculations for for each wateryear, each month, and each operating year

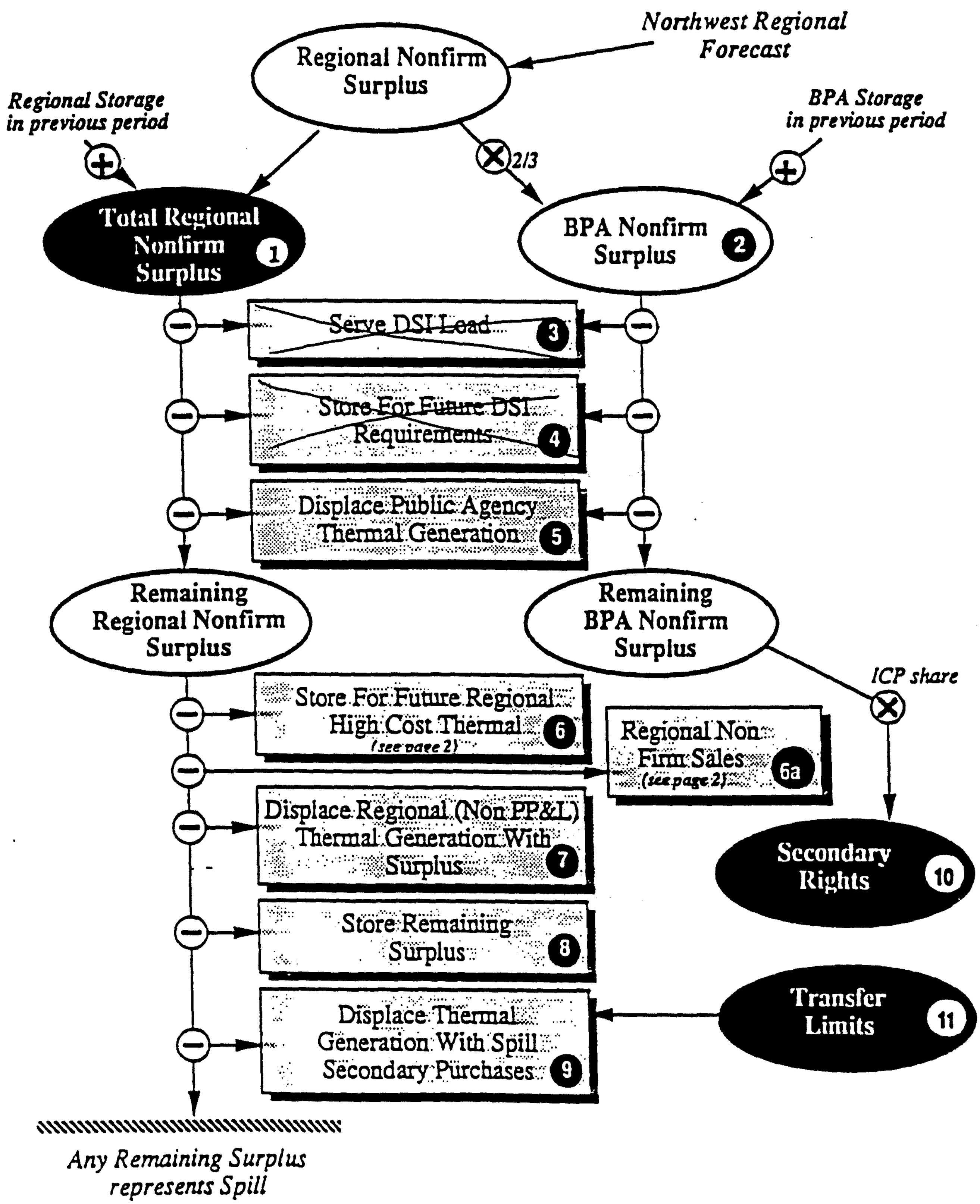
Algorithm

The Company's seven-state system is fully integrated with members of the Northwest and Rocky Mountain Power Pools, making it necessary to analyze the effect on the Company's power supply operations brought about by the operations of all the utilities in this extensive area. The wholesale energy markets available to the Pacific Northwest region, those in California, Nevada, and the Desert Southwest, must also be represented in order to evaluate their direct effect on the operations of each of the utilities within the Pacific Northwest.

As one example, assume that the Company has an energy surplus in one month as a result of the integrated operation of regional hydroelectric facilities. Pursuant to the provisions of the Pacific Northwest Coordination Agreement to which the Company is a party, this surplus must first be made available to the other parties to the Agreement who are energy deficient. Once this obligation has been satisfied, any remaining Company surplus could then be made available to wholesale markets inside or outside the Pacific Northwest. Because power sales to wholesale markets are highly competitive, the regional energy surplus situation must be examined before the ultimate disposition of any Company surplus can be determined.

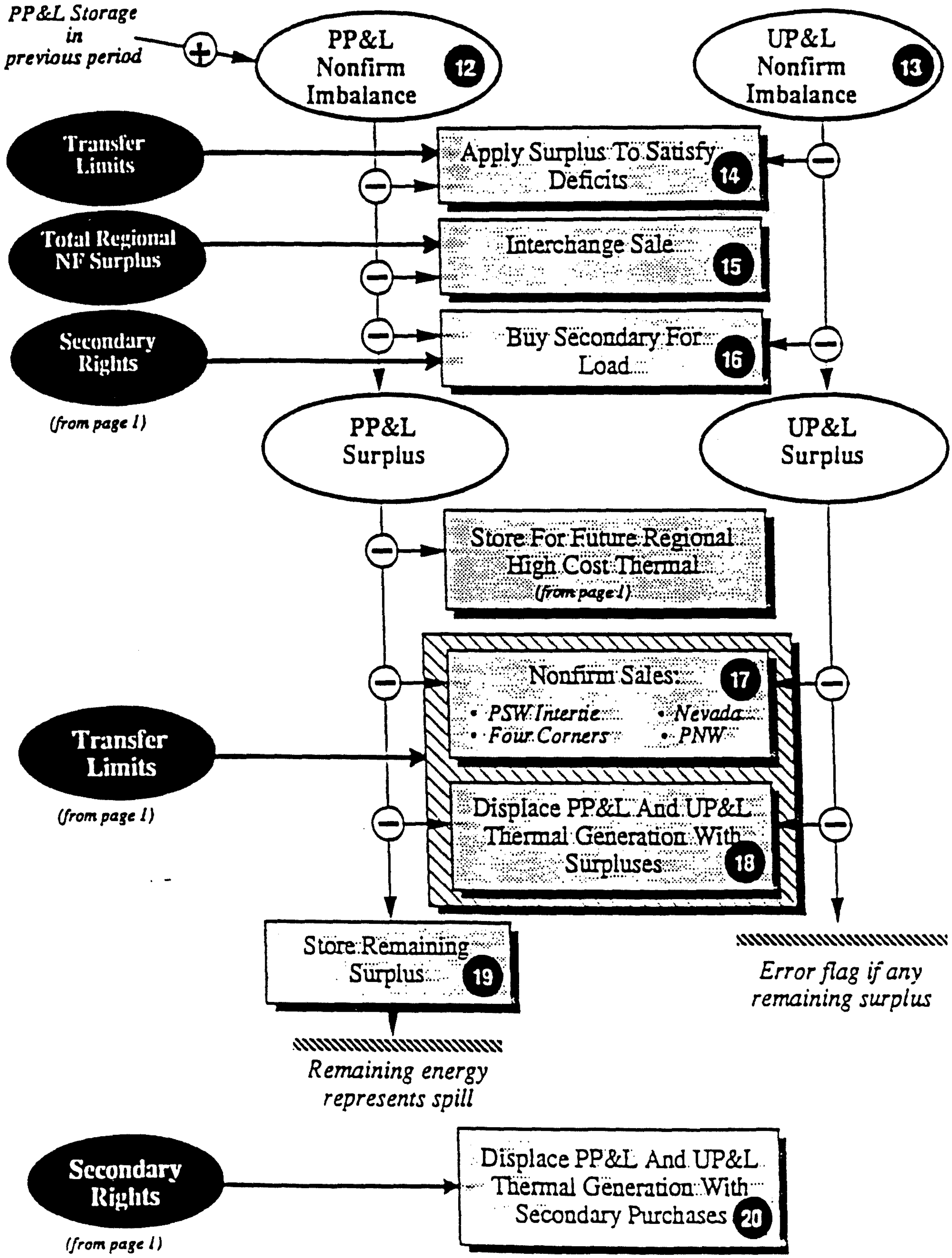
Figure 5, "Production Cost Algorithm Flow Chart" was prepared to provide an overview of the algorithm used in the production cost model. The algorithm is run for each of the 50 years of historical monthly hydro availability. The weighted average of the 50 monthly results for the variable components of the production cost study (nonfirm wholesale sales and purchases, thermal production, interchange sales and intertie wheeling) is combined with the fixed input data to calculate the total wholesale sales revenues, purchased power expense, wheeling expense and fuel expense.

PRODUCTION COST ALGORITHM
Flow Chart (1)



Notes:
1. Flow Chart terms and descriptions are included

PRODUCTION COST ALGORITHM
Flow Chart (1)



Notes:

Notes to Production Cost Algorithm Flow Chart

1. Total Regional Nonfirm Surplus
The sum of the Regional Nonfirm Surplus, any Undisposed Firm Surplus, and Regional storage in the previous month. The Regional Nonfirm Surplus comes from BPA's Northwest Regional Forecast, an annual analysis of current and projected Regional loads and resources.

2. BPA Nonfirm Surplus
Two-thirds of the Regional Nonfirm Surplus plus BPA storage in the previous month which represents BPA's hydro capability as a percent of total regional hydro capability.

3. Serve DSI Load
BPA serves the top quartile (interruptible portion) of the Direct Service Industry (DSI) load with its nonfirm surplus. July thru December, any excess DSI interruptible load over BPA's nonfirm surplus is served and charged to the DSI Advanced Energy Account. Any excess of BPA's nonfirm surplus over DSI interruptible load reduces this account. January thru June, any excess DSI interruptible load over BPA's nonfirm surplus is unserved. Any excess of BPA's nonfirm surplus over DSI interruptible load reduces the Advanced Energy Account. This account is zeroed out each July 1st.

4. Store For Future DSI Requirements
Working back from June to the current month, the excess of the DSI interruptible load over BPA's nonfirm surplus is accumulated. BPA's nonfirm surplus is calculated ignoring storage and undisposed surplus. The accumulated surplus is never < 0 in any month while working backwards. Critical hydro is used during July thru December, and Operating hydro is used in January thru June. BPA stores to meet this expected future requirement up to its storage accumulation limit.

5. Displace Public Agency Thermal Generation
BPA makes any remaining nonfirm surplus available for purchase by Public Agencies to displace their thermal generation. The price of BPA's energy must be less than the average production cost of the generation being displaced. Displacement is done in reverse production cost order.

6. Store For Future Regional High Cost Thermal
Regional displaceable thermal generation is calculated as the sum over all Regional thermal units of net availability less minimum generation (as defined by the displacement limit input). Regional displaced thermal generation is the minimum of the remaining Regional nonfirm surplus and Regional displaceable thermal.

Any excess of remaining Regional nonfirm surplus over Regional displaced thermal generation is stored to displace future Regional high cost thermal generation, up to the Region's storage accumulation limit. Regional high cost thermal generation is calculated by looking back from the following June, accumulating high cost thermal generation (assumed to be zero from April thru August). PacifiCorp is assumed to do 5% of this storage, which represents PP&L's share of regional storage, and is limited by PP&L's storage accumulation limit and nonfirm surplus.

6a. Regional Non Firm Sales
The sales that other Northwest utilities make to the Pacific Southwest across the Southwest Intertie. These sales further reduce the region's surplus and limit Pacific's access to the PSW market. This calculation affects the determination of the Southwest Intertie condition (see 17 below).

7. Displace Regional (Non PacifiCorp) Thermal Generation With Surplus
Displace the non PacifiCorp share of Regional thermal generation with the remaining Regional nonfirm surplus. Displace plants to minimum generation levels in decreasing average production cost order.

8. Store Remaining Surplus
Store any remaining Regional nonfirm surplus up to the Regional storage accumulation limit, taking into account any BPA storage.

9. Displace Thermal Generation With Spill Secondary Purchases
If, after storing, the Region is predicting spill (remaining Regional nonfirm surplus is greater than 0), displace Regional thermal generation with spill secondary purchases. Displace plants to minimum generation levels (as defined by the spill displacement limit input) in decreasing average production cost order. PacifiCorp's displaced generation is assumed to have been met by secondary purchases from BPA. Displacement of UP&L's plants is constrained by the West to East transmission limit.

10. Secondary Rights
Secondary available for purchase by PacifiCorp is determined by multiplying the remaining BPA nonfirm surplus by PP&L's and UP&L's combined ICP shares.

11. Transfer Limits
Monthly energy values limiting East to West and West to East energy transfers. West to East limits represent existing and planned transmission capability between PacifiCorp's Jim Bridger and Naughton plants. East to West transfer limits are the output of the Transfer Program. The Transfer Program convolves hourly loads in Wyoming and SW Wyoming with 3 state outage probability representations of PacifiCorp's generating units in Wyoming and transmission facilities connecting these units and the West.

12. PacifiCorp Nonfirm Imbalance
The sum of PacifiCorp's net thermal availability, system hydro, firm energy purchases, and storage from the previous month, less firm energy sales and total system load

13. UP&L Nonfirm Imbalance
The sum of UP&L net thermal availability, system hydro, firm energy purchases, and storage from the previous month, less firm energy sales and total system load

14. Apply Surpluses To Satisfy Deficits
If either PP&L or UP&L is energy deficit, the surplus system transfers energy to satisfy the other's deficit, constrained by the appropriate transfer limit between the systems.

15. Interchange Sale
If PP&L has a nonfirm surplus greater than the Total Regional Nonfirm Surplus, then the difference between PP&L's Nonfirm Surplus and the Total Regional Nonfirm Surplus is PP&L's interchange sale.

16. If Deficit, Buy Secondary For Load
Any remaining PP&L nonfirm deficit is covered by secondary purchases from BPA up to PPL's secondary rights and secondary purchases up to the Regional surplus. If these purchases are insufficient to cover the deficit, any remaining deficit is covered by secondary purchases from a generic extra-regional source. Any remaining UP&L nonfirm deficit is covered by secondary purchases from a generic source.

17. Nonfirm Sales
Any remaining surplus is sold to secondary markets. The secondary markets identified in the model are SW Intertie, Northwest, Four Corners, and Nevada. These markets are addressed in highest to lowest price order. The nonfirm surplus of the PacifiCorp system directly connected to the market is sold first. If there is any remaining market, the surplus of the other system is sold, subject to the transfer limit between the subsystems. The sellable surplus of each subsystem in each market is determined by comparing the average production cost of the system's resources with the particular market price and a required profit margin. In this way, energy from resources which are too expensive are not included in the nonfirm surplus available for sale in a given market.

The Northwest, Four Corners, and Nevada energy markets are defined as monthly energy values and associated monthly prices. The SW Intertie market is complicated by transmission access constraints and is described below.

Southwest Intertie Sales
Adjusted intertie capacity is defined as the usable intertie capacity less firm sales to the southwest by utilities in the region plus firm imports to the Northwest.

Remaining free wheeling and priority access to the intertie are reduced by PP&L's firm energy sales. On the AC intertie, priority sales are only charged the IS wheeling rate. On the DC intertie, all sales are charged both the IS and ET rates, regardless of priority.

Priority Access Sales - Conditions 2 And 3 Only *(see below)*

PP&L's priority Southwest sale is the minimum of PP&L's remaining priority access, and PP&L's sellable nonfirm surplus. If there is any remaining priority access, UP&L's sellable nonfirm surplus is sold, subject to transmission limits. The adjusted intertie capacity is reduced by the amount of this sale.

Condition 1 (Sellable Regional Surplus exceeds Adjusted Intertie Capacity)

PP&L's sells a pro rata share of its sellable nonfirm surplus. The calculation of the pro rata share includes UP&L's Regional resources.

Condition 2 (Regional Surplus exceeds Adjusted Intertie Capacity)

PP&L's sells a pro rata share of its total surplus (not exceeding the sellable nonfirm surplus). The calculation of the pro rata share includes UP&L's Regional resources.

Condition 3 (Regional Surplus is less than the Adjusted Intertie Capacity)

PP&L sells all of its sellable nonfirm surplus. UP&L's sellable nonfirm surplus can be sold subject to remaining intertie capacity and the transmission limit between the subsystems.

Wheeling

Apply free wheeling to nonfirm sales. Again, priority sales beyond the free wheeling limit are charged the IS rate only.

Intertie Losses

Calculated by multiplying PP&L's nonfirm southwest sales by the SW Intertie loss factor.

18. Displace PP&L and UP&L Thermal Generation With Surpluses

Displace thermal generation in reverse average production cost order. If one system's thermal plant is not fully displaced by that system's remaining surplus, the remaining surplus of the other system can be used to further displace the plant, subject to the transmission limit between the systems. Plants are displaced to their minimum generation level.

19. Store Remaining Surplus

Any remaining PP&L nonfirm surplus is stored, up to PP&L's storage accumulation limit.

20. <u>Displace PP&L and UP&L Thermal Generation With Secondary Purchases</u>

If PP&L and UP&L's secondary rights are greater than zero, displace thermal generation in reverse average production cost order to minimum generation levels. Do this while BPA's secondary price is less than the production cost of displaced generation. If, in a given month, the Intertie is not fully loaded (Condition 3), BPA charges a single secondary price for thermal displacement energy. If the Intertie is fully loaded (Condition 1 or 2), BPA charges different rates for energy to displace "high cost" and non "high cost" thermal plants. Displacement of UP&L plants with secondary purchases is constrained by the West to East transmission limit.

Inputs

Inputs into the production cost model include: 1) retail loads, 2) thermal plant data, 3) hydroelectric generation data, 4) firm wholesale sales, firm wholesale purchases, and firm wheeling contracts, 5) Pacific Northwest regional data, and 6) nonfirm wholesale sales and purchase market data.

1. The retail load represents the firm retail loads that the Company serves within all of its jurisdictions. These loads have been weather normalized to reflect the load that would be served under normal temperature conditions.

2. The amount of energy available from each thermal unit and the unit cost of the energy is needed to calculate the net power costs. To determine the amount of energy available, the Company uses four years of each unit's historical operating equivalent availability reduced by the unit's average maintenance. Average maintenance is based on the same 4-year period as is used for the equivalent availability calculation. In this way, any correlation between forced outage and the amount of maintenance is maintained.

   The unit cost of energy for each unit is determined by using four years of historical burn rate data and actual (test period) coal prices which have been adjusted for known and measurable changes. By using average maintenance and four years of historical availability and burn rate data, annual fluctuations in unit operation and performance are smoothed.

3. The hydroelectric generation in the Pacific Northwest is directly related to streamflow conditions, making it an integral and important part of determining the Company's net power cost. Fifty years of monthly hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources are input into the model. The hydro data that is input into the production cost model is based on the output of the Northwest Power Pool's Hydroelectric Regulation Computer Program (Hydro Regulation). Data from the Hydro Regulation is based on actual streamflows for the period August 192~~8~~9 through July 1978. The Hydro Regulation simulates the hydroelectric generation at each facility on the major rivers in the Pacific Northwest based on inputs provided by each of the member utilities, Idaho Power Company, and the Assured Operating Plan of the Canadian Utilities. The purpose of the Hydro Regulation is to maximize the firm energy capability of the Pacific Northwest hydroelectric system, and is based on hydroelectric plant efficiencies, storage capabilities and requirements, minimum flow requirements (including fish requirements), regional loads and resources, and non-power operating constraints.

The input of hydro generation in the Utah division was calculated as the actual average monthly hydroelectric generation from the Utah division plants for the years 1974 through 1991

4. The data for firm wholesale sales, purchases, and wheeling are all based on contracts to which the Company is a party. Each contract specifies the basis of the quantity and price. The contract may specify an exact quantity of capacity and energy or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. The price may also be specifically stated, may refer to a rate schedule or may be based on some type of formula. Normalized wholesale contract information usually includes an adjustment for present rates.

5. There are several types of regional data required as inputs to the model. The most significant is the Pacific Northwest nonfirm surplus. The regional nonfirm surplus is the amount of energy that is available within the region in excess of the region's firm load needs. It is closely related to the region's hydro capability, and is therefore considered to be a water year dependent variable. The inputs include fifty water years of monthly regional nonfirm surpluses. The fifty years of nonfirm surpluses are developed taking into consideration the region's current loads and the resources that would be available under each water year condition. Other data used to represent

the Company's interactions within the region includes: the interruptible portion of the Direct Service Industries (DSI's) load, the amount of thermal resources which are considered to be high cost, and the regional storage capabilities.

6. The production cost model requires inputs relating to four wholesale sales markets. These markets are the Pacific Northwest, the Pacific Southwest (via the Pacific Northwest/Southwest Intertie), Four Corners, and Nevada. The size of each market is determined by the available transmission and is reduced by any firm wholesale sales scheduled over the respective transmission path, forced outages, or other known restrictions. Nonfirm wholesale sales prices are set to reflect prices expected under normal conditions and are based on judgment which is guided by historical nonfirm wholesale prices, water conditions and reservoir levels in the Pacific Northwest, actual levels of competition experienced, and oil and natural gas prices. Prices for nonfirm purchases are determined using judgment based on Bonneville's nonfirm power rate schedule and historical experience.

Model Inputs

- System load
  - Retail load by division: PPL and UPL divisions, temperature adjusted
- Firm wholesale sales and purchases
  - Capacity and energy quantity
  - Revenue/Costs
- Thermal resources
  - Maximum dependable capacity
  - Minimum generation level
  - Heat rate
  - Production factor
  - Maintenance schedule
  - Fuel cost
- Hydroelectric generation
  - 50 water-year generation history
- Wheeling
  - Divisional transmission constraints
  - Rights to Intertie
  - Loss factors
  - Wheeling expenses
- Pacific Northwest regional data
  - 50 water-year regional load and resource balance
  - 115 water-year streamflow converted to weights
  - Storage
  - Regional high cost thermal resources
- Secondary sales market
  - Minimum mark-up
  - Market size
  - Secondary sales price
- Secondary purchase market
  - Interchange price
  - Regional secondary purchase price
  - BPA non-firm purchase price
  - Regional secondary spill price
  - Emergency purchase price

Outputs

The variables that are dependent upon the availability of hydroelectric generation (and therefore streamflow conditions) are calculated for each month of the study and are outputs of the model. These variables are:

1. Interchange energy and hydroelectric storage transactions as performed under the Pacific Northwest Coordination Agreement;

2. The amount of thermal generation required to meet firm and nonfirm loads;

3. The hydroelectric energy stored or spilled due to the lack of a market;

4. Special (nonfirm) sales both within the Pacific Northwest and the markets in California, Nevada, and the Desert Southwest; and

5. The secondary energy purchased. The availability of secondary energy is based on the level of surplus hydroelectric generation available in the Pacific Northwest as well as the Company's load and resource balance.

The values of the dependent variables are averaged over the fifty water years and the "normal" results are written out in a text file along with all of the power cost information which is constant with respect to water years. Microsoft Excel macros are used to reformat the text files and add the summary pages which make up the familiar Net Power Cost Output. Model results can be output in a monthly format or totaled for annual results.

There are a number of diagnostic reports that may be requested. The model logs each of the calculations it performs on most variables as it steps through the model algorithm. This information can be written out for each water year or averaged over the water years. This portion of the model is not particularly user friendly and requires an experienced analyst to produce and interpret the reports.

Model Limitations

- Time element
  - Monthly energy oriented
- Transmission
  - Divisional transmission constraints only
- Thermal resource availability
  - Historical average, instead of probabilistic
- Model algorithm
  - Simulation based on orderly set of decision, instead of optimization
  - Brokering not allowed

Normalization

<u>Normalization</u>

- Retail load
  - — Temperature adjusted
- Thermal generation
  - — 4-year average production factor
  - — 4-year average maintenance
  - — 4-year average heat rate
  - — Fuel cost
- Hydro generation
  - — Weighted averages of 50 water-year history
- Short term firm sales and purchases
  - — 2-year weighted average
- Non-firm market
  - — Prices
- Transmission availability
  - — Adjusted for known and measurable changes

<u>Annualization</u>

- Annualize changes occurred during the test period to the beginning of the test period
- For example:
  - — Changes in wheeling cost
  - — Expired wholesale sales/purchase contracts
  - — New wholesale sales/purchase contracts
  - — Price changes in contracts
  - — Energy and capacity changes in contracts
  - — Out-of-period adjustments

Types of Semi-annual Studies

- Type 1
  - — Temperature normalization
  - — Thermal normalization
  - — Hydro generation normalization
- Type 2
  - — Temperature normalization
  - — Thermal normalization
  - — Hydro generation normalization
  - — Annualization of known and measurable changes
- Type 3
  - — Temperature normalization
  - — Thermal normalization
  - — Hydro generation normalization
  - — Annualization of known and measurable changes
  - — Normalization of known and measurable changes in Pro-forma period