EXHIBIT NO. ___(WJE-9)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: W. JAMES ELSEA

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-06____** **Docket No. UG-06____**

EIGHTH EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF
W. JAMES ELSEA
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

The AURORA Dispatch Model

PSE uses the AURORA model to estimate the cost of its resource portfolio used in serving its core customer load. The model is described below: first in general terms to explain how the model operates; followed by discussion of the inputs which are significant to the fundamentals based program.

Overview

AURORA is a fundamentals based program meaning that it relies on factors such as supply, demand and transportation which drive the electric energy market. Unlike many models which use historic data to predict the future, AURORA uses forward looking information in a dynamic process to simulate changes in the market. AURORA uses hourly demand and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm.

AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

AURORA also has the capability to simulate the addition of new-generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

AURORA Logic

AURORA models the competitive electric market using the following modeling logic and approaches to simulate the markets: prices are determined from the clearing price of the marginal resources. Marginal resources are determined from "dispatching" all of the resources in the system to meet loads in a least-cost manner subject to transmission constraints. This process occurs for each hour dispatched. Resulting monthly or annual prices are derived from that hourly dispatch. The commitment and reserve decisions are done prior to dispatch.

The unit commitment logic simulates operation of generating units that cannot cycle hourly. These units commit to operate based upon the value they create over an operating period. Once committed, units will run at either maximum available capacity or at minimum capacity depending on the value created in each hour of operation. To make the determination on unit commitment, AURORA will iterate to a solution of consistent prices and resource operation for a forecasted period based on the minimum up and down times for the generating units in analysis. Using the pre-forecast prices AURORA examines the economics of committing the nit given the unit dispatch cost and the minimum up and down times.

To provide system reliability, a portion of resource capacity can be reserved to provide stability in the integrated electrical supply system in the event of unexpected outage conditions. AURORA determines the reserve requirement for each area and then takes a set of the higher cost units out of the dispatch stack for the hour. The portion of resources that are reserved for system reliability cannot be dispatched into the system based upon dispatch for economic profitability. Hence this leads to higher prices during periods where generation supplies are near full utilization.

AURORA optimizes the use of hydro energies over a weekly period. It uses hydro constraints such as instantaneous maximums and minimums and the number of hours of sustained peaking maximums. Given the annual and monthly energy factors for each area, AURORA shapes hydro to flatten load (net of hydro) as much as possible. It accounts for regional hydro imports and exports, too.

Long-term optimization studies are used to forecast capacity expansion resources and retirements. In AURORA you can put future resource units in the database with pre-determined start dates, or use the long-term logic that uses market economics to determine the long-term resources and the start or retirement dates. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. The model assumes that new generators will be built (and existing generators retired) based on economics. The economic measure used is real levelized value (revenues less cost) on a $ per MW basis. Investment cost is included in the cost portion of the formula. Also, the methodology assumes that potentially non-economic contracts will not influence the marketplace and that someone will capture the opportunity value of non-economic contracts. Therefore contracts are not modeled into the pricing.

AURORA determines resource value from the difference between market price and resource cost. This determination is performed for every hour for every resource in the region. Thus, a very accurate value is developed which takes into account system value during on peak and off-peak and other hours, and during daily, seasonal, and annual periods of time. The modeler can specify the use of variable operation and maintenance expenses along with fixed operation and maintenance expense in the computation.

The net present value per MW of each resource is found for all periods of the study. This net present value may be used in long term future analysis for determining whether a new resource should be added to the system or whether an old resource should be dropped.

In summary, AURORA simulates the economic dispatch of resources to meet demand requirements. AURORA:

- Solves the whole system dispatch simultaneously.
- Dispatches hourly (with sampling capabilities, where appropriate).
- Determines the market-clearing prices from marginal costs.
- Values all the resources in the system.

Assumptions

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. The continental U.S. is generally divided into three regions and only small amounts of electricity are traded between these regions. The western most region, called the Western Electricity Coordinating Council (WECC) includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas for example.

For modeling purposes the WECC is divided into sixteen areas primarily by state except for California which has northern and southern regions, Oregon and Washington which are combined, and Alberta and British Columbia which are combined. These areas approximate the actual economic areas in terms of market activity. The data bases are organized by these areas and the economics of each area is determined uniquely.

Load forecasts are created for each area. The load forecast includes the base year load forecast and an annual average growth rate. Since the demand for electricity changes both over the year and during the day monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: for example, the monthly load shape would show southern California's summer peak demand and the northwest's winter peak.

All generating resources are accounted for. Information on each resource includes its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). Previously, the generating resource landscape saw few changes; however there are currently numerous plants under construction and many more in the planning stage. The model incorporates resources that are under construction with expected on-line dates, and is updated as resources move from the planning stages to the construction and production stages.

The price of fuel is an important factor in determining the economics of electric power production. The three most important fuels are natural gas, fuel oil and coal. The fuels need to be priced appropriately for each area. For example, a plant in Washington may receive its gas from Canada at the Sumas hub, whereas a plant in Southern California may receive gas from New Mexico or Texas at the SoCal Border hub, which are priced differently.

Water availability has great influence on the price of electric power in the Northwest. Water flow data on the Columbia river has been collected for over 100 years; however only sixty years (1928-1987), or fifty years (1928-1977) in some cases, are currently accepted by the regional boards and commissions as accurately accounting for all loss factors and hence only these sixty years are used in the analysis. There is also much hydro power produced in California and the Southwest (e.g. Hoover Dam) but it does not drive the prices in those areas as it does in the Northwest. In those areas the normal expected rainfall and hence the average power production is assumed for the model.

Electric power is transported between areas on high voltage lines. When the price in one area is higher than another, electricity will flow from the low priced market to the high priced market which will move the prices closer together. The model takes into account two important factors that contribute toward the price: first, there is a cost to transport energy from one area to another which limits how much energy is moved; and there are physical constraints on how much energy can be shipped between areas. The WECC high voltage lines were not designed like the interstate highway system to move goods easily and efficiently around the country. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas.

The operation of resources within the electric market is modeled to determine which resources are on the margin for the WECC in any given hour. Within WECC there are approximately 3,200 generating resources.

For all AURORA databases, long-term average demand and hourly demand shapes for these areas are input. These demand areas are connected by transmission links with specified transfer capabilities, losses, and wheeling costs.

Existing supply-side generating units are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off-peak minimums, and sustained peaking constraints are also input. Demand-side resources and price-induced curtailment functions are defined, allowing the model to balance use of generation against alternatives to reducing customer demand.

Provides price and value forecasts for each time period being studied.

AURORA applies economic principles, dispatch simulation and bidding strategies to model the relationships of supply, transportation, and demand for electric energy.

AURORA forecasts market prices and operation based on forecasts of key fundamental drivers such as demand, fuel prices, and hydro conditions.

AURORA is able to forecast point estimates in seconds and minutes, and produce Monte Carlo stochastic analyses in minutes and a few hours.

In addition to market prices, AURORA provides information on resource value, portfolio value, net power cost, risk and uncertainty analysis, and resource planning. With appropriate inputs, AURORA can be used for near-term analysis (next day/week) to very long-term analysis (20 plus years).

Along with the software, EPIS delivers default databases. To install AURORA and its North American databases, users run the set-up program from a CD-ROM or via the Internet. The underlying assumptions may be reviewed using the database tools within AURORA.

Furthermore, the user can make changes to data (using spreadsheet-like grids) in the database and run scenarios and what-if cases. Users are able to add their own proprietary data to create their own databases.

A real strength of AURORA is that it is transparent to the user. Users can view all assumptions and results. For example, using the STEP FUNCTION of AURORA, users may step through the model, following the progress of results on an hourly basis. Results are presented in straightforward graphical and spreadsheet-like grids.

Periodic model and data updates are provided via the Internet. Model upgrades for user-specified needs are part of the annual license fee as long as requested changes are of general interest and not proprietary in nature.

Moreover, along with its modeling power, AURORA is easy to use. AURORA runs on any of the following PC based operating systems: Windows XP/ /NT 4.0. The software uses the Microsoft .net framework which is the latest in graphical user interfaces (GUI's). It integrates well with Microsoft Office products; for example, MS Excel.

AURORA documentation and help are context sensitive, and available directly from the Internet.

Modeling Methodology

AURORA is specifically designed to model wholesale electricity prices in a deregulated generation market.

In a deregulated generation market, at any given time, prices should be based on the marginal cost of production. In a competitive electricity market, prices will rise to the point of the variable cost of the last generating unit needed to meet demand.

One of the principal functions of AURORA is to estimate this hourly market-clearing price at various locations in the electric market. AURORA uses a fundamentals approach in estimating prices, reflecting the economics and physical characteristics of demand and supply.

AURORA estimates prices by using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm.

The operation of resources within the electric market is modeled to determine which resources are on the margin for each area in any given hour. The databases include all the NERC reliability areas in the North American national electric market including WECC.

For all AURORA databases, long-term average demand and hourly demand shapes for these areas are input. These demand areas are connected by transmission links with specified transfer capabilities, losses, and wheeling costs.

Existing supply-side generating units are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off-peak minimums, and sustained peaking constraints are also input. Demand-side resources and price-induced curtailment functions are defined, allowing the model to balance use of generation against alternatives to reducing customer demand.

AURORA uses this information to build an economic dispatch for the markets. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

AURORA also has the capability to simulate the addition of new-generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

In summary, AURORA simulates the economic dispatch of resources to meet demand requirements. AURORA:

- Solves the whole system dispatch simultaneously.
- Dispatches hourly (with sampling capabilities, where appropriate).
- Determines the market-clearing prices from marginal costs.
- Values all the resources in the system.
- Provides price and value forecasts for each time period being studied.

Information from AURORA

AURORA forecast capabilities include forecasting for month-by-month and annual forecasts. With AURORA's daily forecasting capabilities, the model can be used for next day or next 30-120 day forecasts. The capacity expansion or long-term optimization mode may be used to develop a resource retirement and capacity expansion plan for medium- to long-range price projections.

AURORA provides the following information:

Electric price forecasts:

- Geographic areas and trading hubs
- User-specified time periods--hourly, daily, monthly and annual
- On-peak, off-peak or other defined sets of hours

Resource value forecasts:

- All existing generating units
- Future generating-unit alternatives
- Demand-side resources
- Hourly, daily, monthly and annual time periods

Resource strategy forecasts:

- Uses NPV of resource market profitability
- Optimal resource strategies for long-term runs

Portfolio analysis:

- User-defined sets of contracts and resources
- Monthly and annual time periods
- Hourly results may be written using VB scripting capabilities within AURORA

Uncertainty analysis:

- Price, value and defined portfolios
- Input sampling of key fundamental drivers
- Transmission usage and congestion

Information from AURORA is readily and easily transferred to Excel or virtually any other MS Windows program. In addition, AURORA provides the above information in MS Access database files or MS Excel Spreadsheets. The option of writing output to Internet HTML formats is also available.

Drivers and Inputs

AURORA uses the fundamental economic drivers of the electric market to make its forecast. That information includes:

- Electricity demand by geographic area; annually and monthly including hourly shapes.

- Supply-side resources (all major generating units) in the system. Resource heat rates, fuel types, resource-commitment data and other resource information. Future resource alternatives are used in long-term optimization studies.

- Demand-side resources including an interruptible price curve.

- Fuel prices by fuel type and location.

- Hydro information for AURORA's hydro-optimization logic.
- Transmission costs and constraints.
- For uncertainty analysis, Monte Carlo sampling from statistical distributions for demand, fuel prices, hydro conditions and other drivers is used to forecast price distributions.

Users manage the cases and analyze the drivers to electricity-market forecasts by selecting the underlying assumptions of the analysis. The projections are created using assumptions for the chosen inputs, such as electricity demand growth, fuel prices, and gas-fired combined-cycle generation efficiency and cost. For example, the low electricity market scenario could include low-demand growth, low fuel prices, and optimistic assumptions about combined-cycle combustion turbines. The combination of assumptions may consist of outcomes that the user believes are plausible. A user can model the conditions, cases and options a decision-maker wants to evaluate. Without any programming, you determine the assumptions used in each forecast or study.

Modeling Logic

AURORA models the competitive electric market using the following modeling logic and approaches to simulate the markets:

AURORA market prices are determined from the clearing price of the marginal resources. Marginal resources are determined from "dispatching" all of the resources in the system to meet loads in a least-cost manner subject to transmission constraints. This process occurs for each hour dispatched. Resulting monthly or annual prices are derived from that hourly dispatch. The commitment and reserve decisions are done prior to dispatch. Commitment works as follows:

COMMITMENT LOGIC

The unit commitment logic simulates operation of generating units that cannot cycle hourly. These units commit to operate based upon the value they create over an operating period. Once committed, units will run at either maximum available capacity or at minimum capacity depending on the value created in each hour of operation. To make the determination on unit commitment, AURORA will iterate to a solution of consistent prices and resource operation for a forecasted period.

AURORA does a true economic unit commitment. Unit commitment occurs prior to dispatch. Unit commitment allows the user to define the minimum uptime and minimum downtime for each unit. AURORA performs an iterative process that runs the first hour of the study. The units that will run and the units that will not run are defined. Note: The only interdependent hour-to-hour cross-time optimization occurs in the unit commitment logic. It does this by doing a pre-forecast of prices (using an iterative approach to begin with). Using the pre-forecast prices AURORA examines the economics of committing the unit given the unit dispatch cost and the minimum up and down times.

Once committed, the unit's minimum segment is removed from the dispatch and only the upper segment is subject to dispatch.

The Step by Step logic:

1. A pre-forecast of prices for the commitment period is made. For each dispatch period and for each non-cycling resource.

   AURORA will do a pre-forecast of the prices. The first hour is run without commitment logic to obtain a price for an hour. AURORA then takes that price and using the demand, net of Hydro, determines a ratio. To determine the next 167 hours AURORA uses this ratio to determine the prices.

2. Unit value for the commitment period is computed (including startup costs).

3. If unit is running, check current prices and commitment period. If the price is economic then the unit continues to run.

4. If economic, and the unit has been down for at least the minimum down time, the unit is committed for the period.

   If not economic, then if the unit is currently committed, keep the commitment if the time since committed is less than the commitment period (Min Up Time or one week). If the unit is not currently committed then do not commit. If the unit is not committed, it may run if the market price is greater than (Variable) times the fuel cost of the unit. The variable is defined on the logic tab.

5. If the unit is committed, run full out when the dispatch cost is less than the market price.

6. When the dispatch cost is greater than the market price run the unit at the minimum level.

The input controls for the commitment and dispatch of resources are found in the Resources Table and the Fuel Table and for non-cycling units they consist of:

- Min-up Time and Min-down Time
- Non Cycling Percent

- Start-up Costs
- Must Run

Unit Cost Formula: Variable Cost + Fixed Cost + Startup Cost = Total Cost

Define a minimum uptime in hours (maximum 168) and a minimum downtime in hours.

If a commitment unit does not commit it remains in the dispatch at a penalized dispatch cost. Dispatch Penalty Formula: Dispatch Cost + Dispatch Penalty = Dispatch Penalty Cost

Other unit types are:

- Cycling Units – Cycling units can be dispatched hour by hour.
- Hydro Units
- Storage Units

The modeling of these units will be discussed in the dispatch logic, hydro logic and storage logic.

OPERATING RESERVES

To provide system reliability, a portion of resource capacity can be reserved to provide stability in the integrated electrical supply system in the event of unexpected outage conditions. The portion of resources that are reserved for system reliability cannot be dispatched into the system based upon dispatch for economic profitability. Hence this leads to higher prices during periods where generation supplies are near full utilization.

AURORA handles operating reserves by determining the reserve requirement for each area and then taking a set of the higher cost units out of the dispatch stack for the hour. The set of resources is equal to the reserve requirements percent (%) for the market area. Spinning reserves can be modeled by using must run units.

DISPATCH

With commitment and reserve decisions done prior to dispatch, the dispatch works as follows:

1. AURORA builds a dispatch stack for each area.
2. Given native load the marginal unit is found in each area.
3. Pricing is determined from the marginal unit using incremental (linear) interpolation (or if selected, second order interpolation, or exact supply pricing by area.)

4. Given transmission capabilities and cost (losses and wheeling), economic power flows are determined.

5. Using "genetic algorithms" (combination of random and best) small sets of power flows are allowed to take place.

AURORA will consider the potential benefits associated with shifting or moving power.

6. Given net loads in each area, marginal units are again found.

7. The process is repeated until no significant benefits can be obtained by additional power flows.

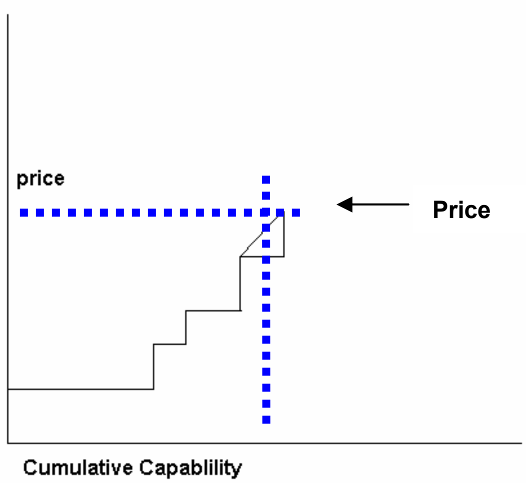
These market prices are the foundation for the value, cost, and risk analysis performed with AURORA.

Dispatch Pricing Options

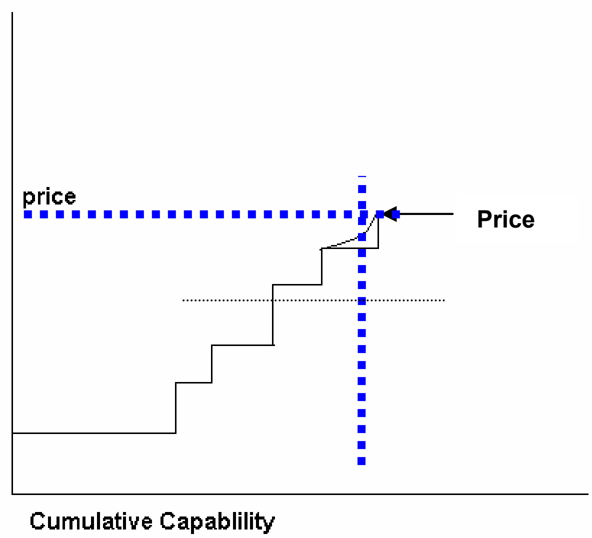
The last unit sets the market-clearing price even though it is fractionally dispatched. The price of the fractional dispatch is set by Incremental (Linear) Interpolation (the default), or if selected, Second Order Interpolation or the exact supply pricing approach.

Incremental (Linear) Interpolation

(Default Dispatch)



Second Order Dispatch



Dispatch Resolution

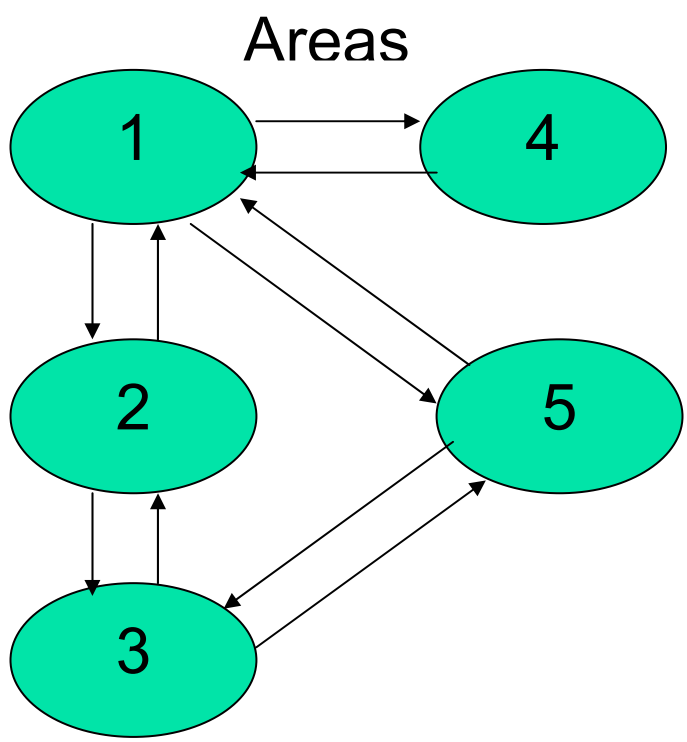
The user has the option to the control of dispatch resolution on the Logic Tab. The default resolution is "Normal." Normal represents what happens in the market because it does not reach a dispatch solution with 100% of losses or wheeling.

Resource Dispatch Margin

The resource dispatch margin (in percent) determines what margin is required for a resource to run. This margin is applied to all resources in the system. The user can specify on the Logic Tab the dispatch margin. This margin is multiplied by a monthly shape factor if one is pointed to by a value in the box for monthly shape for dispatch margin. The Monthly Shape for Dispatch Margin Pointer to a Monthly Shape Vector, located in the Monthly Shape Factors Database Table, for shaping the dispatch margin.

Summary

In summary, the dispatch provides a system dispatch that is computed using genetic algorithm techniques, AURORA determines clearing prices in all system geographic areas for each dispatch hour. Each area will have its own marginal unit (the next unit to dispatch in the area) for a particular hour. Those are displayed along with the area prices for an hour.



1. A price sorted resource stack is determined for each area.
2. A clearing price is found for each area given the native demand.
3. Economic flows are determined and sorted by value (price difference).
4. A small set of the most economic flows is used.
5. The clearing price is found for each area given native load and imports and exports.
6. Using genetic/Darwinian algorithm techniques, steps 3 through 5 are repeated until stability is reached.

HYDRO SHAPING LOGIC

AURORA optimizes the use of hydro energies over a weekly period. It uses hydro constraints such as instantaneous maximums and minimums and sustained peaking maximums. Within shaping constraints, AURORA shapes hydro to flatten load (net of hydro) as much as possible. It accounts for regional hydro imports and exports, too.

Specifically, hydro resources are handled as a resource with a fixed hourly energy. The annual and monthly energy factors for each area or resource are input into AURORA. AURORA then uses shaping logic to shape the hydro for weekly (weeks begin on Mondays) periods. Inputs for shaping are a shaping factor, the instantaneous maximum, the instantaneous minimum, and the number of hours for sustained maximum.

The program works as follows:

1. The average demand for the month for the area is found.
2. The average hydro energy for the month for the area is found.
3. AURORA then shapes the hydro using the shaping factor and the following formula:

   Hourly Hydro Shape = (1 + shape factor * (hourly demand - average monthly energy)/average monthly hydro energy) * monthly energy factor * annual energy factor.

4. AURORA checks the instantaneous maximum and minimums. If there are any violations, the excess, or underage, is spread or taken evenly from the other hours.

5. AURORA checks the sustained maximum. Any violation is once again spread evenly to the other hours and AURORA loops back to the maximum and minimum checks.

6. If the constraints cannot be satisfied, AURORA will change the input shaping constraints to 1, 0, and 1 and modify the formula to use average monthly energy in the denominator. It will print a message informing the user that this has occurred.

The user has a choice to shape hour by each market area or across market areas. With **Use all Areas for Hydro Shaping** switch on, demand for all areas in the system is aggregated and the total demand is used for shaping hydro rather than the demand in the area the hydro is located. In general, for the Eastern Markets hydro is modeled for the respective market areas, and in the Western Markets all areas are used for hydro shaping.

EMISSION LOGIC

Emissions can be an important fundamental driver. AURORA allows an unlimited number of emission types to be modeled via input. Emission rates are input for each resource and emission prices and limits are input for each emission type.

Emission cost is computed using the following formula:

Emission cost = (emission rate - limit) x heat rate x emission allowance price / 2,000,000

Treatment of emission cost is controlled under the AURORA Assumptions Tab. Emission cost can be included in the dispatch or in the value by using the appropriate check box.

Note that emission data will always be displayed so this only determines where AURORA uses it.

ENERGY STORAGE LOGIC

AURORA models energy storage resources, i.e. pumped storage, batteries, etc. A resource is treated as a storage project if it references a fuel type that begins with word "Storage".

To define the storage project characteristics, the model uses the standard resource input variables, as well as additional inputs for recharge capacity, storage limits, and project initial contents. The charging / generation cycle efficiency is defined through the resource heat rate.

Heat Rate - For storage resources, enter a value such that the ratio of 3412/Heat Rate gives the storage efficiency for the unit (3412 being 100% efficient).

Fuel - Energy storage resources must reference a fuel name that begins with "Storage".

Recharge Capacity - (Text) The maximum rate (MW) at which a storage resource can be recharged. This value defines maximum output on the storage side during charging. Energy input required to achieve this recharge rate will be higher by the reciprocal of unit efficiency. Recharge capacity can be changed on an annual basis by using the name of an annual alpha vector in this field.

Maximum Storage - (Text) The maximum live storage content of the storage resource in MWh. This value can be changed on an annual basis by using the name of an annual alpha vector in this field.

Initial Contents - (Single) Initial storage content of the storage resource at the beginning of the study. This value is input as a fraction and is multiplied by the Maximum Storage value to get initial contents. The value used here should reflect expected storage contents at midnight on the first Sunday of the first month of the study.

At the beginning of each week during the run, AURORA determines a charging and generation schedule for each storage project for the coming week. The inputs mentioned above are used, as well as a dynamically updated hourly area price forecast information for the week. Within each day across the week, the model identifies the combination of hours in which it is cost-effective to store and to generate without violation of the project storage constraints. It assures that revenue during the generation hours exceeds the cost of charging energy adjusted for cycle efficiency, plus any variable O&M costs incurred. Once the hourly schedule for the week has been determined, it is locked in and used to modify area load for the hours actually being dispatched as the simulation proceeds through the week.

In any individual dispatch hour, the actual hourly cost of recharge energy or the revenue from hourly generation is based on the area price determined by the full dispatch for that hour.

The default configuration for AURORA is to optimize the recharge/generation schedule, under the week-ahead price forecast, on a daily basis for each day of the week except Sunday. The schedule for Sunday will be determined using an extended price forecast into the following week. This option can be disabled on the Logic tab under Run Setup on AURORA's main form.

Use Extended Period for Storage Scheduling. When the switch is on the storage scheduling decisions for Sunday are made by extending the forecast into the following week, using a scheduling horizon through Tuesday of the following week.

With this switch turned off, scheduling decisions for Sunday will be made only on Sunday forecast hours.

There are two issues the user should be aware of when evaluating the value of energy storage projects using AURORA.

1. It is important to note that the week ahead hourly price forecast AURORA uses for determination of the hourly charging/generation schedule can and probably will differ from the prices determined by the full dispatch for the week ahead. It is possible for projects that have a marginally economic schedule based on forecast prices, to result in an uneconomic operation for a week if the full dispatch prices are substantially flatter than the forecast prices. This was an infrequent occurrence under testing with the standard AURORA databases.

2. It is important to run enough dispatch hours to capture the full economics of the charging/generation schedule. EPIS recommends using a minimum hourly setup configuration of every hour for at least one week a month.

Monthly Hydro Shaping:

The hydro shape for a month will reflect the data input in the Hydro Shaping table

***Long-term Optimization Logic*.**

Long-term optimization studies are used to forecast capacity expansion resources and retirements. In AURORA, you can put future resource units in the database with pre-determined start dates. Or, you can use the long-term logic that uses market economics to determine the long-term resources and the start or retirement dates. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. AURORA assumes that new generators will be built (and existing generators retired) based on economics. The economic measure used is real levelized value (revenues less cost) on a $ per MW basis. Investment cost is included in the cost portion of the formula. Also, the methodology assumes that potentially non-economic contracts will not influence the marketplace and that someone will capture the opportunity value of non-economic contracts. Therefore contracts are not modeled in the pricing piece of AURORA.

In preparing for Long-term optimization studies, users will identify New Resources to be evaluated in the study and determine parameters for the study.

NEW RESOURCES

In the New Resources Table in the database is where the user defines a new resource and its operating characteristics. For example, the type of resource: Wind, Solar, Nuclear, Coal, Gas, Etc.

The new resources table contains columns that allow the user to define all the variables of a new unit, including when the potential unit will be placed in service. These variables provide controls for placing operating constraints on all the units in the system.

AURORA will calculate a value for each unit. This value is a Real Levelized Net Present Value (NPV) in $/MW. The capital cost is part of Real Levelized cost. AURORA uses the Real Levelized cost to make decisions about new units.

AURORA RESOURCE VALUE

AURORA determines resource value from the difference between market price and resource cost. This determination is performed for every hour for every resource in the region. Thus, a very accurate value is developed which takes into account system value during on peak and off-peak and other hours, and during daily, seasonal, and annual periods of time.

The user can specify the use of variable operation and maintenance expenses along with fixed operation and maintenance expense in the computation. We recommend however, that the value computation be performed on all forward costs. This produces the best economic view of the resource.

The net present value per MW of each resource is found for all periods of the study. This net present value is used in long term future analysis for determining whether a new resource should be added to the system or whether an old resource should be dropped.

STEPS IN LONG-TERM OPTIMIZATION

1. The first iteration begins with no changes in resources for the time period of the study. (AURORA uses resources in Resources Table)
2. Enumerates all new resources
3. Computes value for each existing resource
4. Computes value for each new enumerated resource
5. Sorts resource values
6. Selects a small set of the most negative value existing resources to retire
7. Selects a small set of the most positive value new resources to add.
8. Rerun AURORA to compute electric prices and resource value
9. AURORA repeats the Genetic/Darwinian algorithm until the system stabilizes

This is done on a gradual basis because large changes to the resources would change all of the assumptions used to compute value

This optimization approach provides an excellent approximation for how the competitive marketplace will select resources in the long-term. Resources that create value on a going-forward basis will be constructed while those that have no value on a going forward basis will be retired.

A primary result of a future analysis is a **NEW RESOURCE MODIFIER** table. A resource modifier table is created and becomes part of the AURORA input database. This table is the only output saved to the input database.

The output of this study may be used to input assumptions for other long-term analyses where the assumptions are applicable. The purpose of a resource modifier table is to add or retire resources in the main resource table of the applicable database.

Bidding Logic

In addition to electricity price forecasts based on the fundamental drivers, users may reflect non-fundamental price behavior by modeling bidding in the market place. This may be modeled using Bidding Logic.

The bidding logic is an optional feature in AURORA. The **Use Bidding Logic** box is used to control whether AURORA uses bidding logic for resource operation.

For the bidding logic to implemented, users provide input in the following tables:

In the Resources Database Tables, bidding factors and bidding shapes may be input. If they are, then they are used only if this checkbox is set.

To reflect what suppliers may bid, Bidding input put in the Resources Table and the Fuel Table, where a **Bid is equal to (1+bidding factor) x unit's marginal cost x hourly shape factor**

Bidding Factors: Specify by generating units or fuel types.

Bidding Shapes: Specify hourly shape by units by pointing to Weekly Shaping Factor Table.

The following are instructions on the Resources Table relating to bidding:

This table provides the input assumptions and parameters for all existing resources in the region being modeled. Generally, when a -1 appears in the Resource Table, the model retrieves the correct input parameter from general parameters for each fuel type.

Bidding Factor: A (Text) column that allows a value. If this value is a numeric value greater than 0 then it is a factor, which will be added to one and multiplied by the total resource variable cost to get the dispatch cost for the resource.

This simulates bidding at prices that are greater than the cost of a resource. This number will override any general resource dispatch margin, which may be used. If this value is a non-numeric alpha value then it points to an annual alpha vector where the values are input annually. If this value is a negative one then the fuel default is used. If this value is less than negative one then it is a pointer to a monthly shape vector where monthly values are input.

Bidding Shape: A (Text) column that allows the number of the weekly shape vector (of hours) to use for shaping the bidding factor hourly (they are multiplicative). An alpha string may be used in this field. If it is, then it points to an annual alpha vector, which must point to a monthly shape factor. The monthly shape factor then contains the weekly shape vector for each month. By this means, you can vary the shape by month and year. If this is zero, -1 or not given, then no shape is used.

The following are instructions on the Fuel Table relating to bidding:

Bidding Factor - (Text) If this value is a numeric value greater than 0 then it is a factor, which will be added to one and multiplied by the total resource variable cost to get the dispatch cost for the resource.

This simulates bidding at prices that are greater than the cost of a resource. This number will override any general resource dispatch margin, which may be used. If this value is a non-numeric alpha value then it points to an annual alpha vector where the values are input annually. If this value is less than negative one then it is a pointer to a monthly shape vector where monthly values are input.

SELECTING OPTIONAL LOGIC SETTINGS:

In AURORA, the user is able to control many of the parameters that relate to the above logic by using the switches and settings on the Logic Tab.

Use Operating Reserves box is used to control whether AURORA reserves generation for operating reserve purposes.

If this box is checked, then AURORA will reserve a percentage of resources at the top of the stack for operating reserves (the capability of these resources will be set to 0 for the hour). The percentage of resources reserved is set to 6.5 percent by default. The Areas table in the input database can be used to change those defaults. The exact formula used in the reserve requirement calculation is as follows:

ReserveRequirement = (ResourceCapabilityForArea + HydroResourceReservesForArea) * PercentReserveRequirementForArea/100 - HydroResourceReservesForArea

Use all Areas for Hydro Shaping When the switch is on demand for all areas in the system is aggregated and the total demand is used for shaping hydro rather than the demand in the area the hydro is located. See the explanation of the hydro shaping logic for more information.

Use Price Caps allows the use of price cap inputs in the area table.

Use Extended Period for Storage Scheduling When the switch is on the storage scheduling decisions for Sunday are made by extending the forecast into the following week, using a scheduling horizon through Tuesday of the following week.

With this switch turned off, scheduling decisions for Sunday will be made only on Sunday forecast hours.

Use Second Order Dispatch The second order dispatch switch computes the marginal pricing for load above the marginal resource by using a second order equation rather than the linear interpolation of the standard dispatch.

This option will result in somewhat lower prices and will cause AURORA run time to significantly increase. Generally, we recommend that this switch not be used. Consult with EPIS.

Normalize Demand and Hydro box is used to control the normalization of hourly demand and hydro factors.

When the box is checked, then hourly demands and hydro factors, for a month, for the hours that are dispatched are modified so that the monthly average is exactly one.

For demand, there is also a flag (default is true) for each demand number, which can be set in the Escalation of Demand table. Both the global box on this tab and each individual demand numbers flag must be set for the demand for that number to be normalized. However, if you are doing daily mode runs, then the normalization of demand will be for all hours in the month and hydro factors will not be normalized.

When the box is not checked, no modifications are made to the input hourly demands or the hourly hydro factors computed by the hydro optimization routine.

Use Bidding Logic box is used to control whether AURORA uses bidding logic for resource operation.

In the Resources Database Tables, bidding factors and bidding shapes may be input. If they are, then they are used if this checkbox is set and are not used if this checkbox is not set.

Use Ramp Rate box is used to control whether AURORA uses resource ramp rates in determining resource capabilities. Ramp rates affect the resource capacity that is available to dispatch in any given hour, making it a function of the resource output in the previous dispatch hour.

Ramp rate logic will only be effective if AURORA is set to dispatch for all hours (8760 per year). Ramp rates are input as a percent for individual resource units or by fuel type. Generally, the ramp rate logic will affect market prices during shoulder hours when load is increasing.

Dispatch Resolution drop-down allows the user to control the dispatch resolution. For most purposes, this should be left at normal. The dispatch provides a system dispatch that is computed in a radically new way. Using genetic algorithm techniques, AURORA determines clearing prices in all system geographic areas for each dispatch hour. System resources are not used like they were in the old dispatch (the master resource table will be empty); each area will have its own marginal unit (the next unit to dispatch in the area) for a particular hour. Those are displayed along with the area prices for an hour (see hour area in the view button screen). Contact EPIS before changing the dispatch resolution.

Dispatch resolution affects what % of difference exists between existing areas. Selecting a higher than normal resolution will result in a smaller difference between areas. The default is NORMAL, which represents reality more accurately.

Use Congestion Pricing box is used to control whether AURORA will use congestion pricing on the effective link wheeling rates. You may add the column "Link Congestion Year" to the Link table and set the first year you want each link to use congestion pricing (default, pricing will be used for the link). When congestion pricing is used, link-wheeling rates are determined by the following formula:

70 - Exponent for congestion pricing (by default).

The user can change this with the Congestion Exponent box.

Congestion Wheeling Rate = Input Wheeling Rate times Fraction Link Loaded ^ Exponent times 1000

The effect is to multiply the Input Wheeling Rates by the values from the chart below with the x-axis representing the congestion or the fraction the link is loaded.

Note - a value of one occurs at about .905 with an exponent of 70.

Resource Dispatch Margin The resource dispatch margin (in percent) determines what margin is required for a resource to run. This margin is applied to all resources in the system. The dispatch margin is multiplied by a monthly shape factor if one is pointed to by a value in the box for monthly shape for dispatch margin.

Monthly Shape for Dispatch Margin Pointer to a Monthly Shape Vector, located in the Monthly Shape Factors Database Table, for shaping the dispatch margin.

Non-Commitment Penalty The Non Commitment Penalty allows the user to specify the "penalty" or increment (in percent) in the dispatch cost to be used to dispatch a commitment type unit when it has not committed for operation.

By default, this is set to 2900 percent or a 30 times penalty so commitment-type units will not run if not committed.

Economic Commitment Penalty. The Use economic non-commitment penalty option allows the user to compute the economic penalty applied to commitment type units if not committed for operation.

The penalty is calculated as one half of the difference between the units cost and the expected revenues over the minimum up time.

Risk Analysis

Prices and values of resources and portfolios may be forecast and understood under conditions of uncertainty. AURORA's speed makes it possible to get results in a matter of hours, not days. To see the effects of uncertainty, AURORA samples from statistical distributions of key drivers. AURORA can be run in Monte-Carlo or Latin Hypercube mode, results are tabulated, and a full set of statistical results can be analyzed. For instance, the effects of summer-peaking situations may be understood or the effects of hydro uncertainties can be examined. Because the basic economics of the system are not linear, this kind of analysis can lead to insights that would not otherwise be available. On the Risk Tab, the user can select risk analysis to be able to perform Uncertainty Analysis.

In the Risk Analysis demand, fuel, hydro, transmission, portfolio demand and resources can be sampled from distributions including normal, log-normal, uniform and binomial distributions. Also, the user can sample from a user-defined distribution. The sample draws may be done as Monte-Carlo or Latin-Hyper-cube sampling. For each iteration sampled, AURORA provides detailed sample/iteration results, statistical results (mean and standard deviation), and histogram results

Also, AURORA may be used as a "pricing" application or engine within another Monte Carlo application or system of models.

AURORA Data Elements

Data Elements of AURORA Software

Run Set-Up Controls

Set the Time frame--next hour to very long term (20+years)

Set the Price Forecasts Output

For Areas and Trading Hubs may output prices for following time frames:

Hourly prices
Daily prices
Monthly prices
Annual prices

Resource Forecasting

Hourly, daily, monthly and annual operation, cost, and value
Marginal resources and fuels

Dual fuel modeling

Cycling and commitment resources
Minimum down and up times

Start-up costs

Must-run resources (set monthly or annually)

Multiple Segments and Heat Rates

Ramp rates

Bidding factors by resource
All existing resources (thousands)
Emissions dispatch and reporting
Planned resources
New resource additions

Automatic capacity expansion

Resource Stacks displayed graphically

Resource dispatch order information available

Portfolio Value

Hourly, monthly and annual cost, revenue and value
Hundreds of contracts and resources in each portfolio
Many portfolios examined simultaneously
Many contract types, including a variety of option and must-takes

Basic Variables

Resource cost and availability
Hourly demand by area
Transmission costs and constraints
Demand-side cost and availability
Thermal Resources including ramp rates
True economic commitment logic
Peaking and Non-cycling unit commitments

Hydro Resources
Annual, monthly and hourly factors
Optimization of hydro on weekly basis
Hydro constraints include maximum and minimum stream lows

Flexible new resource definitions
Unlimited new resource types

Unlimited emission types
Market-value-driven resource decisions
Flexible constraints on new resources and retirements

DATA INPUTS

AURORA is very flexible and can be used for a variety of purposes through changing its input data. Below is a discussion of the major input variables, their purposes, constructs, and with some sources for updates. Also it should be noted that the economic assumptions in AURORA can be overridden by user input. For instance, modeling the new FERC price caps in the west requires non-economic assumptions, but can be modeled in AURORA.

In the Appendix is a complete set of AURORA input tables with definition of variables.

Annual Alpha Vectors

Purpose:

Resource parameters that vary by year

Principle Variables:

- heat rates, allows technology improvements for future resources
- variable O&M, differing rates in future for new or existing resources
- fixed and variable O&M of future resources, including capital costs
- rebuild costs, tests recovery of cyclical costs to rebuild generator (e.g., 20 year life cycle of certain equipment)

Annual alpha vectors are used as a reference for variables that may be changed yearly. This table is replacing the Annual Vectors table. This table has the word alpha in it to indicate that the table requires the use of alpha characters in the references to it. The alpha characters are used to indicate that a reference is implied rather than a value. Variables that may be input via the Annual Alpha Vectors table are documented with the variable definition.

Annual Vectors

Purpose:

Inputs varying by year

- resource build and retirement limits
- inflation rate
- fuel pointers to monthly shapes
- hydro pointers to monthly shapes
- annual load escalation

Principle Variables:

- load escalation with differential annual escalation
- inflation rates
- can specify annual fuel costs with differential annual escalation

Data Sources/Tools:

- inflation rates from government agencies: e.g., BLS, OMB, EIA
- inflation rates from subscription companies: e.g., DRI, WEFA
- annual load escalation from NERC regions from Loads and Resources Assessment order forms annual load escalation from FERC 714 filings http://www.ferc.fed.us/electric/f714/F714data.htm

Annual vectors are used as a reference for variables that may be changed yearly such as inflation rates and annual growth in demand. Variables which reference annual vectors include: transmission wheeling (reference monthly shape of transmission costs for each year), new resources (annual maximum number of units), escalation of demand (annual growth rate in demand specified for each area), and general information (inflation rate).

This table is being phased out and replaced by the annual alpha vectors table.

Other vector tables include "monthly shape factors" and "hourly shape factors".

Areas

Purpose:

Specifying the areas for which prices are determined Principle Variable:

- creating new/different areas
- define existing resources, future resources, loads, and transmission
- existing resources: fuel costs, hydro parameters, and load curtailment 'resource'
- future resources: fixed O&M, variable O&M, fuel costs
- loads: base year annual average load, monthly and hourly shapes, annual growth rates
- transmission: paths with transfer limits, transmission charges and loss rates with each other area

Listing of geographic load and resource areas identified in the model. The selection is generally based on significant areas where transmission interconnections with other areas are well defined.

Columns include:

- Area Number - Area identification number.
- Area Name - A name for the area.
- Area Demand Number - A pointer to the column in demand tables to use for the area (the demand tables are the "demand" (hourly) and "demand case" (monthly and annual tables).

- Average Marginal Cost (Optional column type single) - If input, this provides the rolling average marginal cost (over 12 months) to use at the beginning of a run.
- Area Reserve Requirement (Optional column type single) - If this column exists, then the values in the column (including 0 or blank) override the default value of 6.5 % for area operating reserve requirements when the use operating reserves check box is set. The values are input as a percentage.
- Short Area Name (Optional column type text) - If this column exists, then the values will be used for a shortened form of the area name (used with some outputs). If this column does not exist, then the short area name will be the left 5 characters of the area name.
- Price Cap (Optional column type single) - If this column exists, then the non-zero values will set a price cap for the area. The price cap will be artificial and will not effect resource dispatch. It may affect connected hub prices. The Use Price Caps checkbox must also be set.
- Exact Supply Pricing (Optional column type boolean) - If this column exists, then those areas with this column checked will have prices computed based on the exact dispatch cost of the marginal supply side resource. Because of this logic, imports will not be used for the pricing.

Hourly Demand

Purpose:

Hourly load shapes for each month. A set of hourly loads or percentages, which define each month's hourly load shape for each area.Principle Variable:

- historical multi-year averages can be used to specify a 'normal' year
- an actual year can be specified to model either a high or low year data sources
- hourly loads available through FERC 714 control area hourly loads http://www.ferc.fed.us/electric/f714/F714data.htm

This is a data table of hourly load factors for an annual period (8760 + 8 days). Each column is numbered and is referenced by an area or portfolio/power cost entity. In general, EPIS has set up the table columns to match the areas. The load data begins on a Monday and continues for an additional 192 hours (8 days) at the end of the year. This allows for indexing in on the table to the correct beginning day of the week for any year specified (including leap years). AURORA can automatically normalize the hourly demand factors so that the average of the demand factors for the hours being dispatched in a month always equals 1.0. This is controlled from the logic tab. Please note that the columns in the Demand table must be in the following order. Additional columns are not allowed in this table.

Columns include:

Hour - The hour in the year beginning on a Monday at 12:00 - 1:00 a.m.

Number - The identification number as used by the area or portfolio/power cost entity using this table. These numbers must be sequential. This column is repeated for each demand number in the database.

Demand Moderate

Purpose:

Annual average load and monthly shapes

Principle Variables:

- area load forecasts
- monthly load shapes for each area

Data Sources:

- historical EIA utility loads from Annual Energy Report, useful for allocating a larger area forecast to smaller AURORA areas http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html [Table 17]
- NERC load forecasts (compilation of utility forecasts)
- EIA Annual Energy Outlook forecast (utilizing NEMS) http://www.eia.doe.gov/oiaf/aeo/electricity.html

Fuel Moderate

Purpose:

Specify fuel cost and generic operating parameters by resource type

Principle Variables: fuel prices

- resource operating parameters: O&M, availability, commitment and must run designation

Data Sources:

- EIA Annual Energy Outlook forecast
  http://www.eia.doe.gov/oiaf/aeo/supplement/index.html
- EIA historical data, FERC 423, cost of fuel by plant
  http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html
  http://www.ferc.fed.us/electric/f423/form423.htm
- And, various proprietary gas-forecasting services.
  See EPIS Energy links on www.epis.com

Hydro Moderate

Purpose:

Specify hydro energy generation

Principle Variables:

Annual and monthly hydro energy specified in percentage of installed hydro capacity

Data Sources:

- EIA 759 monthly generation, hydro reported by resource http://www.eia.doe.gov/cneaf/electricity/page/eia759.html
- NERC regions resource data
- Power pool and planning information

Link

Purpose:

Specify transfer capability across transmission paths

Principle Variables:

Inter-area transmission path transfer capability

Data Sources:

The primary source of data for this table is a wholesale transmission map. The WECC transmission map showing transmission limits is available from the Western System Coordinating Council (www.wecc.com) or WECC Path Rating Catalog in FERC 715 filing (http://www.ferc.fed.us/electric/F715/F715data.htm). The National transmission map showing transmission limits is available from the North American Electric Reliability Council (www.nerc.com).

For transmission, the primary source of data is wholesale electric transmission tariffs. However, transmission data will be used as incremental wheeling cost and losses components of the marginal-clearing price of unit(s) on the margin. Therefore, the values used here should reflect the cost of transmission and wheeling for the resource on the margin. Counter-flow scheduling and resale of unused firm transmission rights (i.e. non-firm) should be considered in judging the values input to transmission.

Review Data: By activating the "Sys" button on the AURORA toolbar prior to a run you are able to view the transmission system geometry as defined by the Link table.

Monthly Shape Factors

Purpose:

Specify various inputs that change by month

Principle Variables:

- seasonal generation capacity changes
- splitting generation between areas by season
- fuel shapes
- hydro operating parameters

Data Sources:

Existing Resources

New Resources

Purpose:

Specify various inputs that change by month

Principle Variables:

- seasonal generation capacity changes
- splitting generation between areas by season
- fuel shapes
- hydro operating parameters

Data Sources:

- State siting agencies and Western Interstate Energy Board
- News reports (Internet searches)
- Multiple sources: See EPIS Energy links on www.epis.com

This table provides the input assumptions and parameters for new resources types to be evaluated when the model runs a long-term study. It optimizes the expansion and retirement of resources. This table is similar to the resource table. Values in this table, which are set to -1.0, indicate that the value from the fuel table should be used for the area (in the case of hydro).

Heat rate, fixed O&M and variable O&M fields may be input as text strings. If the fields are not numeric, then they are assumed to point to a record in the Annual Alpha Vectors table. Thus values for heat rate, fixed O&M, and variable O&M can now vary by year. For the new resources table, the values will be the values used for all years for the vintage of new resource being created for the capacity expansion. If you need to use changing annual "real" values for a vintage of new resources then the Annual Alpha Vectors table may contain a text string which should point to another record in the Annual Alpha Vectors table which contains the appropriate annual "real" values for that vintage new resource. For the resources table, the values in the Annual Alpha Vectors table will be the annual "real" values used in the run.

The column order in the resources table is not important. Column names must match those below exactly. When adding columns to an EPIS supplied database, you should check your results carefully to ensure that the column names were correct and the data is actually being read.

Columns include:

- Number - Identification number for the new resource type. New resources created for evaluation from these types are numbered sequentially starting at one and if they are actually used in the dispatch, then they are numbered sequential, starting with the next number after the last existing resource.

- Name - The reference name of the resource, used for reporting purposes. The letters "demand" anywhere in a resource name indicate that the resource is a demand side rather than a supply side resource.

  The names are subject to the following constraints:

  - Can be up to 30 characters long.
  - Can include any combination of letters, numbers, spaces, and special characters except a period (.), an exclamation point (!), an accent grave (`), and brackets ([ ]).
  - Can't begin with leading spaces.
  - Can't include control characters (ASCII values 0 through 31).

- Utility - Generally not used for new resources, but you can identify resources by utility.

- Heat Rate - The heat rate assumption for the resource in BTU of fuel energy per kWh delivered. This is a standard measure of energy efficiency for thermal resources and should be the higher heat rate value, not the manufacturers lower heat rate. This field may be left blank for units with zero fuel cost.

- Capacity - The rated plant capacity in kilowatts (not MW)

- Fuel - The fuel identification reference number as identified in the "fuel case" table. Each resource must include a fuel reference number of a valid fuel in the fuel table.

- Area - The area where the resource is located. The resource must be in one of the areas identified in the "area" table.

- Variable O&M - Variable operation and maintenance expense is expressed $/MWh.

- Fixed O&M - Fixed operation and maintenance expense (plus any investment carrying costs) for new resources of this type, expressed in $ per MW-week. A typical input with 3 $/MWh fixed O&M for a unit in full operation would be 3x168 hours per week or $504. Since fixed O&M are not dependent on plant operation, the fixed cost is applied regardless of plant operation. See the appendix article on Investment costs for information on how they should be included in this input.

- Maintenance Begin - day/month/year that maintenance begins. The maintenance will repeat annually from this date forward. See editing summary for information on using the calendar.

- Maintenance End - day/month/year that maintenance ends. This date specifies the period at which annual maintenance will end. When multiple years are run in the model, the maintenance period will be repeated each year beginning and ending on the same day. At this time, varying annual maintenance periods cannot be input to AURORA. When maintenance periods change yearly, the model can be run separately for each year. See editing summary for information on using the calendar. Generally, if you do not want maintenance by date, you should put a 1/1/80 in the maintenance end date and a 1/2/80 in the maintenance begin date in the fuel table only. Put the dates of 1/1/80 in both columns in the resources, resource modifier and new resources tables - a date of 1/1/80 defaults to whatever is in the fuel table. If you want to put non-defaulting dates in other tables, use something like 1/1/81 and 1/2/81 and not 1/1/80 and 1/2/80 because 1/1/80 will default to the fuel table and 1/2/80 will not.

- Forced Outage - The percentage of time the resource will be unavailable due to unscheduled outages. This field reduces the plant capability for each dispatch multiplying the plant capacity from this Table by the quantity 1-forced outage percent/100. This value may be an alpha, which would point to an annual alpha vector. There is the capability to use a number greater than 1000. If this is done, then the logic will use the monthly vector pointed to by the value in the forced outage field less 1000. If the resulting forced outage rate field is negative, then AURORA will assume the absolute value of the field is a pointer to a weekly vector where the hourly forced outage rates are input.

- Maintenance Rate- The percentage of time the resource will be unavailable due to scheduled outages. This field reduces the plant capability for each dispatch multiplying the plant capacity from this Table by the quantity 1-Maintenance Rate/100. This value may be an alpha, which would point to an annual alpha vector. There is the capability to use a number greater than 1000. If this is done, then the logic will use the monthly vector pointed to by the value in the maintenance field less 1000. If the resulting maintenance rate field is negative, then AURORA will assume the absolute value of the field is a pointer to a weekly vector where the hourly maintenance rates are input.

- Non Cycling - Non-zero number indicates percent premium of market price over dispatch cost required to dispatch the resource during the commitment period (one week). Once on, the unit remains on at least at minimum capacity until the next commitment period.

- Must Run - Flag (on is 1, off is zero) which sets the units to a "must run" condition. Units that have this flag set assume a zero cost of dispatch and will be the first units to operate.

- Hydro Number - For hydro resources, any of the hydro shapes in the "hourly hydro factors" and "hydro monthly" tables may be reference for any hydro resource unit. The user may also choose a new hydro shaping factor for any hydro resource by including a new shape in both the "hourly hydro factors" and "hydro monthly" tables and referring to that shape in the "resource" table.

- Minimum Capacity - For non-cycling resources, specifies the minimum capacity at which the unit can run when the non-cycling logic is active. The unit for the input is percentage of resource capacity.

- Begin Date - The beginning date when this resource is available to be included in a capacity expansion. See editing summary for information on using the calendar.

- End Date - The ending date when this resource is available to be included in a capacity expansion. See editing summary for information on using the calendar.

- Annual Max - A reference to the "annual vector" table indicating the maximum number of these units that are available in the year of capacity expansion.

- Overall Max - Maximum number of the new resource type resources that will be created.

- The following fields or columns are optional.
- Resource Group - (Long) The resource group that new resources created from this type will belong to.
- Capacity Monthly Shape - (Long) If this value is greater than zero, then it must be a reference number to a valid row in the monthly shape table where monthly factors for shaping capacity are input.
- Min Up Time - (Long) The minimum number of hours the unit must stay up if committed to run with new commitment logic. Defaults to fuel table if this column is not in the database.
- Min Down Time - (Long) The minimum number of hours the unit must stay down if it is a commitment type (non-cycling non-zero) and not committed with new commitment logic. Defaults to fuel table if this column is not in the database.
- (Emission Type Name) Emission Rate - (Single) This field or fields contains the resource emission rate in lb/mmbtu for the emission type given by the name. The field or column name is the concatenation of the emission type name and "Emission Rate". Monthly rates should not be used for new resources.

Resources

Purpose:

Specify existing resources, costs, and operating parameters

Principle Variables:

Each available resource with its operating parameters:

- configuring hydro to save time and memory by combining like hydro resources in each area
- balancing resources with loads (consistent with statement of self-generation)
- cold-start generators, lower availability by using start up cost
- must-take energy, must run with high minimum capacity
- differentiate between CCCT and SCCT, FOR and minimum capacity

Data Sources:

- ES&D Energy Supply and Demand Report, an annual report by the federal government on existing resources
- EIA 860 (A & B) reports
- http://www.eia.doe.gov/cneaf/electricity/page/data.html

Transmission

Purpose:

Specify transmission prices and losses between each pair of areas

Principle Variables:

- wheeling charges can be specified within each area to get delivered prices specifying within an area will distort generator value computations
- percentage rates for transmission line losses

Data Sources:

FERC tariffs for OAT charges and losses

Weekly Vectors

Purpose:

Specify variables by hour within a week

Principle Variables:

- defines hours in "Conditions", e.g., on-peak and off-peak hours
- allows shaping of resources or contracts
- provides weekly shaping factors by hour that can be referenced by the condition table, the portfolio contract table, the electric price table and/or the resources table. Weeks begin on a Monday.

Columns include:

- Number - A reference number that is referred to in the condition table or the power cost contract table.
- Name - The name of the vector. Not used by AURORA.
- 1-168 - The hourly value of the vector for each hour of the sample week - the first hour is hour 0 to 1 of Monday.

Information on the complete set of AURORA input tables with definition of variables are in the Appendix. This is from the AURORA on-line documentation. It is recommended that users use the on-line information to ensure the use of the latest information.

Sample Output of AURORA

AURORA enables the user to view the results while the results are still in the virtue memory of the computer, or to create an output in AURORA, MS Access or MS Excel. This enables users to view all assumptions and results. Results are presented in straightforward graphical and spreadsheet-like grids.

Operating Platform

Software. AURORA uses the latest software technologies from Microsoft and other leading software vendors. The model is written in Microsoft .net framework.

Ease of use and analysis of multiple scenarios are facilitated by Visual Basic Scripting (VB Scripting) capability in the AURORA software. VB Scripting is used to place results directly in MS Excel.

AURORA can use MS Worksheets for input by linking the worksheets to database tables.

Requires MS DAO and VB Scripting engines (installations are included with AURORA installation)

AURORA input and output are stored in standard Jet databases--MS Jet (Access 97) databases (Excel worksheets are also supported). Input databases are about 3-8 MB each.

We are using the latest MS software and all DLL's etc. included with the installation are the latest MS available.

AURORA is year 2K compliant and as far as we can tell, the MS software included is also year 2K compliant.