Asset Valuation in NERC Regions Using UPLAN

1.0 Network Power Model and Plato Database

1.1 Methodology

Over the last 20 years, LCG has developed as support for its core business a large system of electric and natural gas utility planning and operation system software, the UPLAN System. The centerpiece of our technical capability is the uniquely integrated power system and electricity market modeling system, UPLAN Network Power Model (UPLAN-NPM), which has been developed specifically in response to the new competitive environment of the electricity industry. UPLAN-NPM is a sophisticated multi-commodity, multi-area regional electricity model using the Optimal AC Power Flow and Market (OPFM) algorithm to analyze the economic impacts of competition in a regional power market. It simulates markets and bidding for energy and ancillary services, and uses hourly chronological production costing with Monte-Carlo methodology to simulate uncertainty associated with generators and loads

As a result, the UPLAN system of models can effectively simulate market behavior, analyze potential asset investments, and compute nodal and area-wide market clearing prices, various forward price curves and spark-spread values under multiple restructuring scenarios.

The UPLAN Multi-Market Model simulates the entire energy and ancillary service markets to determine the capacities necessary for energy as well as ancillary services by balancing the demand and various types of ancillary service requirements every hour. The OPF Model then dispatches the resources allocated by the Multi-Market Model to meet the demand, reliability and security. The OPF Model determines the hourly injection of generation, the flows and manages congestion. In addition, there are several other important asset valuation models, such as the Volatility Model and the Merchant Plant Model, which also run from the analysis and prices generated by the OPF Model. The entire operation is illustrated in Figure 1 below.

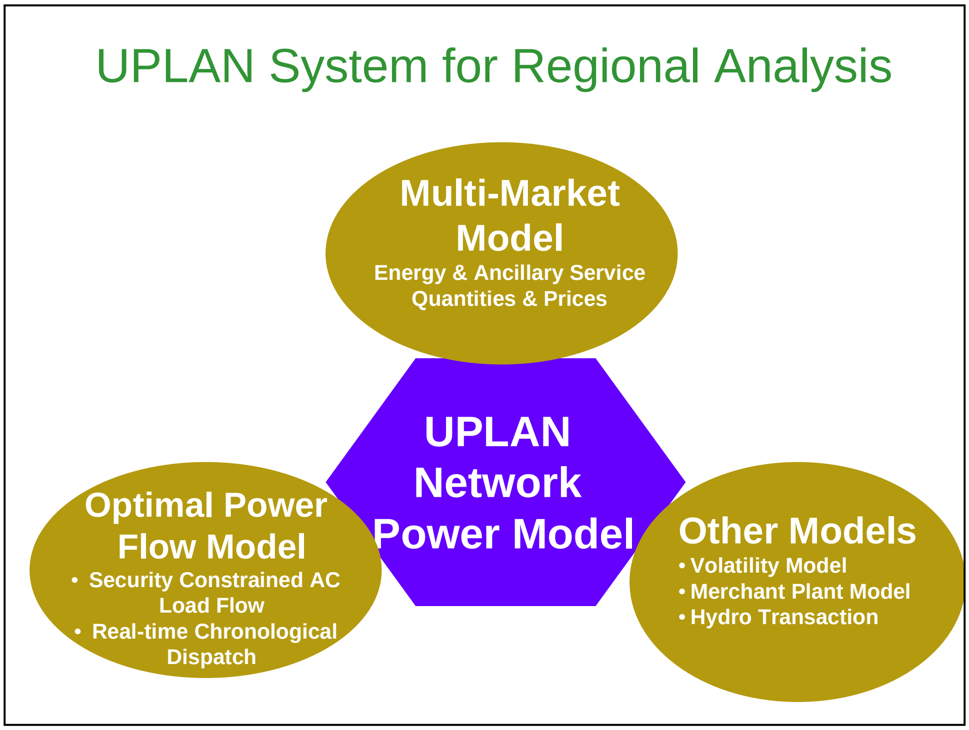


Figure 1. The Integrated UPLAN System for

Comprehensive and Consistent Planning

To determine the forward prices, the electricity market model in UPLAN optimizes the returns from all the trades by taking into consideration all the resource constraints. To meet the short-term economic viability requirements, bidders may choose the option of adjusting the bids over a period of time by an amount over the bidders' marginal cost, as allowed by supply and demand elasticity in the simulated markets. The economic viability criteria may produce ideal prices under competitive bidding. Figure 2 illustrates a 24-hour forecast of energy and ancillary service prices produced by UPLAN Market Model and the real-time prices generated by UPLAN OPF model.

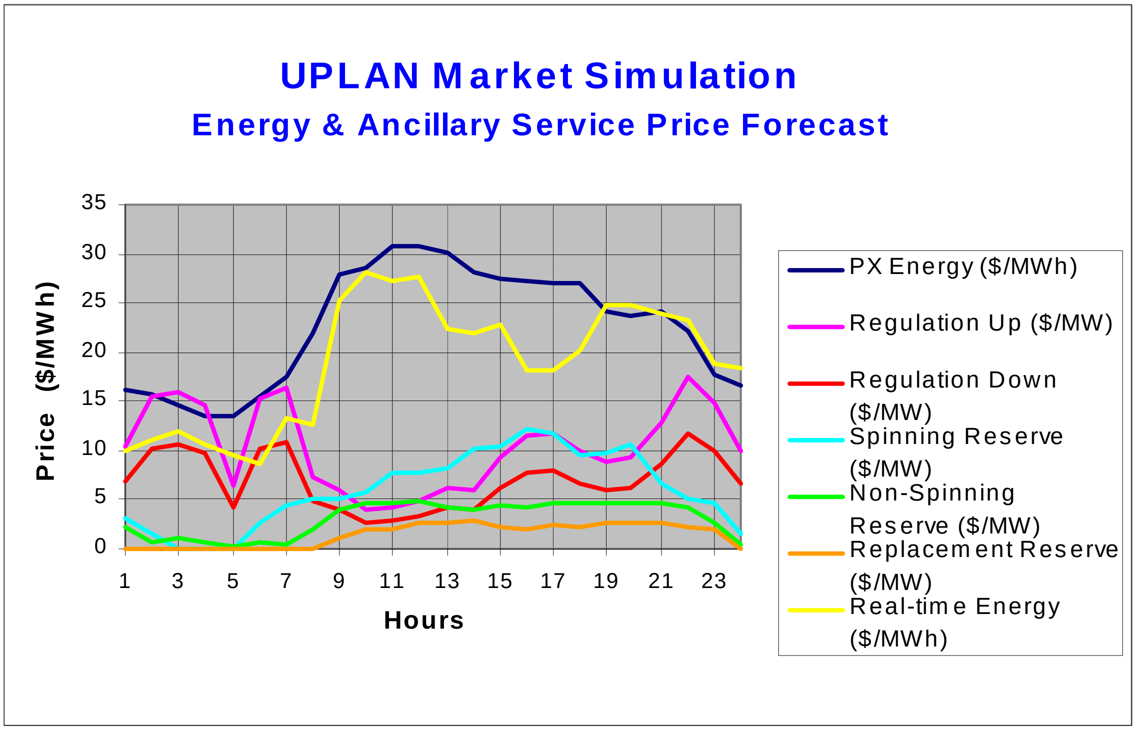


Figure 2. UPLAN Market Simulation

UPLAN's Volatility Model performs systematic evaluation of price volatility due to the uncertainty associated with fundamental drivers such as fuel prices, hydrological conditions, electricity demand, generator and transmission outages, new entrants to the market, and any other critical variables that impact electricity prices. The evaluation is based on Monte Carlo sampling from the probability distribution of the fundamental drivers that contribute to the volatility of energy and ancillary service prices. Some of the output of the model and examples of their uses are described below.

- The probability distribution of prices of energy and each of the ancillary service components are determined.
- Intrinsic and extrinsic values of calls and puts options for energy, A/S and transmission basis differences are reported.
- It provides an alternative calculation of capacity reserve prices as a physical hedge for energy.
- The buyers' premium and sellers' risk across the entire spectrum of strike prices are reported.

The UPLAN Merchant Plant Analysis (MPA) model is an optimization program that identifies the location and timing for installation of new units that meet the required investment criteria over the operating time horizon. In particular, UPLAN's MPA model provides the following analyses:

- Net present value of income over the operating horizon of the asset.
- The distribution of net income for multiple scenarios sampled by the Volatility Model.
- The options value of premiums and risks for the plant at strike prices of interest. These strike prices correspond to $/kW investment in the asset.

Calculation of costs and revenues of a new unit using time series analyses is not only subject to inaccuracies of estimation as stated earlier, but also takes no notice of the impact of transmission congestion. Moreover, such calculations, when used for the evaluation of peakers, are unable to capture the revenue from price spikes and the impact of their intermittent operation. The electricity price spikes account for large parts of the revenues of the peakers.

The Merchant Plant model incorporates revenues from price spikes, capacity and operating reserve and trading emission allowances in determining the income of new units.

1.2 The NERC Regions

On November 9, 1965 a blackout left 30 million people across the Northeastern United States and Ontario, Canada without power. In an effort to prevent this type of blackout from ever happening again, electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to promote the reliability of the electricity supply for North America.

Since its formation, NERC has operated as a voluntary organization - one dependent on reciprocity and mutual self-interest of all those involved. With the continued growth of competition and the structural changes taking place in the industry, incentives and responsibilities are changing, making it necessary for NERC to transform from a voluntary system of reliability management to one that is mandatory, with the backing and support of U.S. and Canadian governments.

The membership of NERC is unique. As a not-for-profit corporation, NERC's members are ten Regional Councils. The members of these Regional Councils come from all segments of the electric industry - investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, and power marketers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

For LCG's forecast process for electricity prices, the NERC regional councils have been grouped into five interconnected areas. These interconnected areas are the Western System Coordinating Council, the Midwest Interconnect, the Eastern Interconnect, the South Eastern Interconnect and the Electric Reliability Council of Texas (ERCOT).

LCG Consulting has developed relational databases of generating plants, loads and transmission lines for the existing electric utility resources for each of the NERC regions. The major source of data for this study has been developed by LCG, based on the databases from the Energy Information Administration (EIA) of the United States Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and various NERC reports.

The simulation inputs are derived for region specific loads, generator and transmission databases, based on the current information developed from a variety of sources for our PLATO database. The operation of the UPLAN system is based on the characterization of the electricity markets as a competitive energy market. The model is market driven and incorporates the energy and ancillary service markets operated by the various ISO, RTO and/or Power Exchanges and take into consideration every aspect of the competitive environment that impacts the operation of the generating units.

1.3 The Transmission Network

LCG has established transmission data and regional networks for each of the major interconnected areas of North America. The five (5) interconnected areas that span the region are the WSCC, the Midwest Interconnect (MAPP, MAIN, ECAR, SPP, Entergy), the Eastern interconnect (ECAR, MAAC, NPCC), the Southeastern interconnect (SERC, FRCC) and ERCOT. Each transmission system was developed representing all major transmission lines and major interfaces that have been identified as having load flow constraints. These constraints on the flow have been externally developed, from detailed load flow studies under extreme conditions and from operating practices.

As of 2001, many of the regions have more than one hundred thousand miles of transmission lines. An equivalent UPLAN transmission system was developed for each region, representing all major transmission lines and major interfaces that have been identified as having load flow constraints. These constraints on the flow have been externally developed, from detailed load flow studies under extreme conditions and from operating practices.

The UPLAN database includes a transmission table that includes the starting and ending nodes, transfer capabilities, electrical characteristics and location of each node. This table also includes regional interface, nomograms, and composite path critical flow limits. Provision has also been made for including wheeling charges and access fees. An interface describes the path in terms of the transmission lines comprising the path and the areas that are interconnected by the path.

In this study, the interfaces are modeled and the ratings are expressed as a linear combination of the lines that make up the path. Some regional networks include several HVDC lines connecting the various areas for transfer of power. These lines, and all the AC connections, are analyzed to determine the operations. By incorporating the interface constraints, the analysis produces a security constrained AC-DC load flow solution.

In Figures 3 to 6, we present maps of the general transmission line configurations used in the regional analyses.

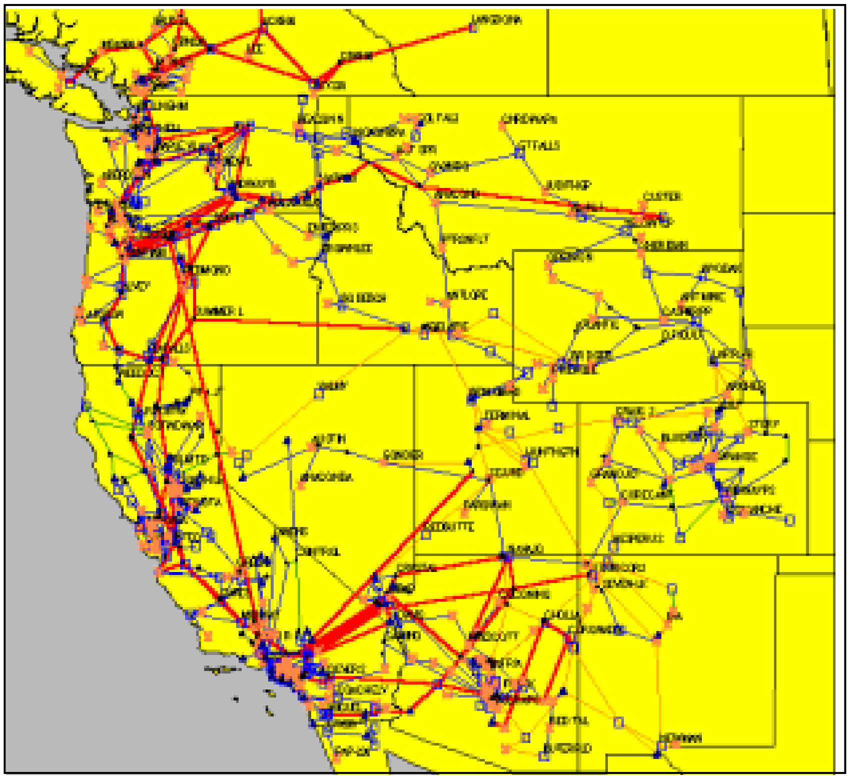


Figure 3. Transmission Line Network for WSCC

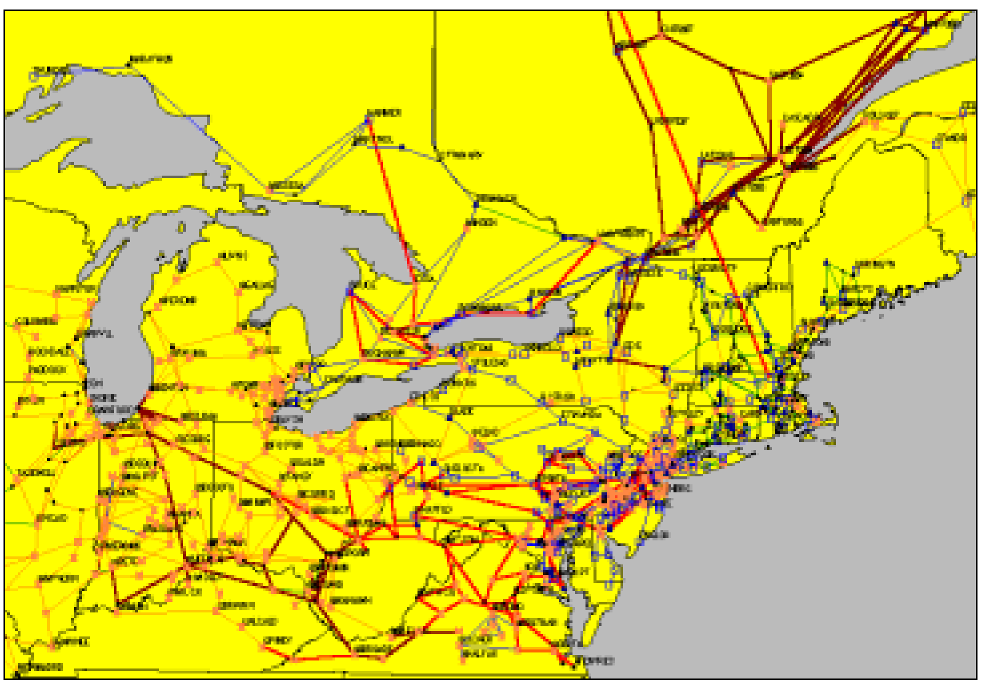


Figure 4. Transmission Line Network for Eastern Interconnect

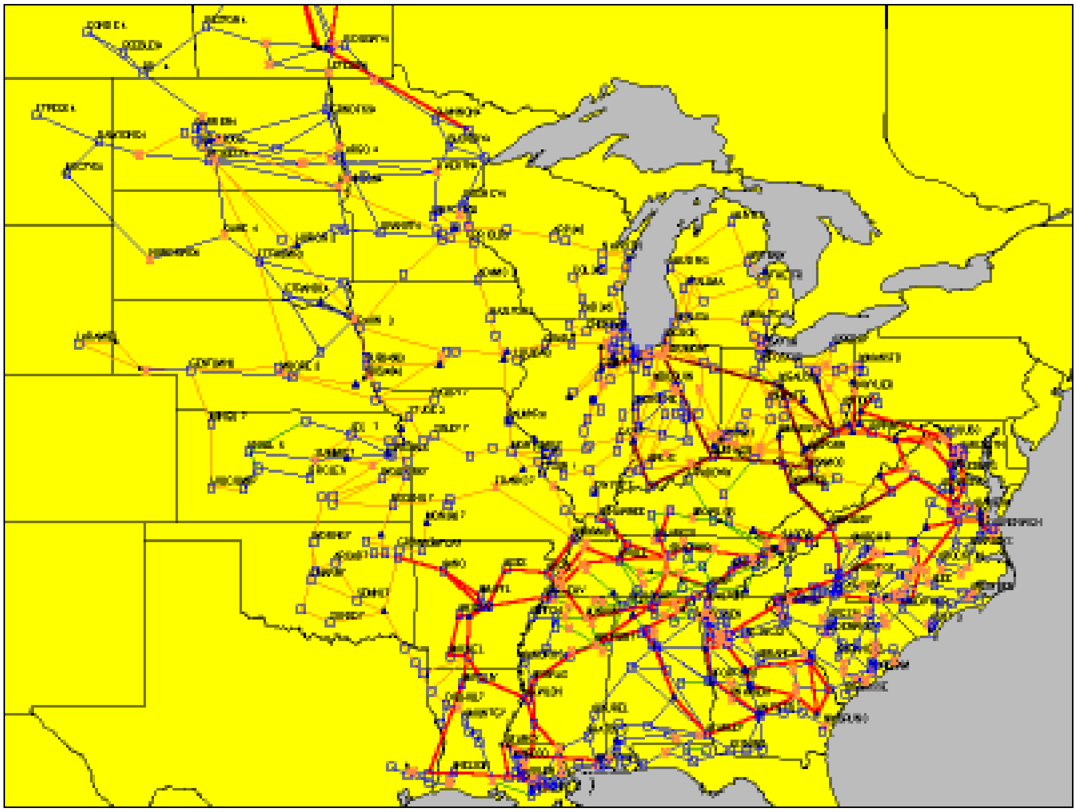


Figure 5. Transmission Network for Midwest and Southeast Interconnects

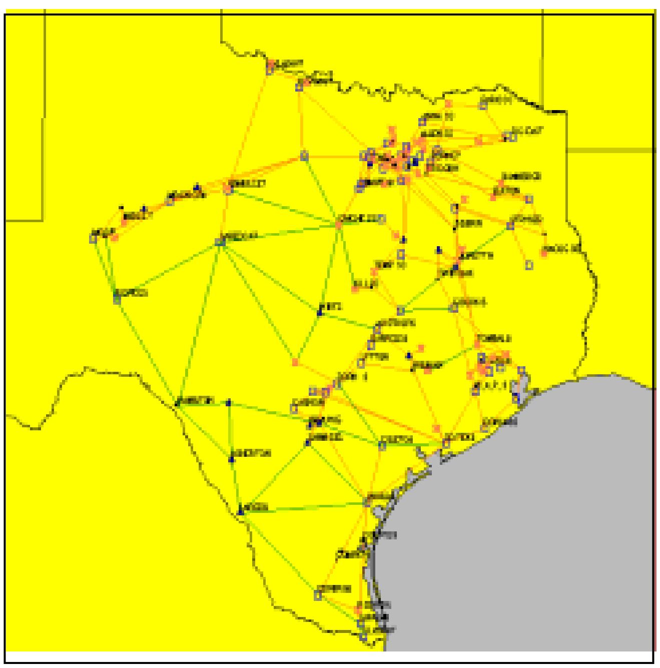


Figure 6. Transmission Line Network for Texas

1.4 The Generator Database

Each region includes a wide variety of generating plants using a variety of fuels, such as coal, gas, nuclear, geothermal, solar, wind turbines, and hydroelectric, and other non-traditional resources. Hydroelectric facilities may constitute a significant part of the resources available to serve the demand, especially in the Canadian providences of the NERC regions. The energy available from these resources depends greatly on the availability of water. UPLAN's hydro model is used to schedule the hydro units to maximize the total operating revenues for each year of the study based on average hydro conditions.

The thermal plants are operated on an economic basis determined by their supply offers in a competitive power market. These units are assumed to form the core of the supply offers to the competitive markets. The thermal plants are generally identified by fuel usage and other operating costs. Each generator in the UPLAN database is assigned a geographically accurate injection node on the transmission network.

The supply-side data includes all the resources in each of the NERC regions. The resource assumptions have been developed employing a range of public and proprietary data sources, including the EIA-OE-411 loads and resources reports.

1.5 Power Resource Options

There are a variety of central generating station options that can be considered as potential future resources in the NERC regions. The initial assessment of technologies does not directly address any specific resources that have been announced, are proceeding through permitting or are under construction. Announced units are considered on the basis of their likelihood of proceeding. New technologies are evaluated after the installation of these resources. The Appendix contains a table of announced units that are to be reviewed.

Five major technologies have been considered. Three technologies are fueled by coal and two are fueled by natural gas. We assume that a new unit must generate a net operating income to meet an annual capital recovery factor that is equivalent to an investment internal rate of return of between 15% - 18%. This ensures recovery of capital as well as recovery of fixed and variable O&M costs, and the fuel costs.

1.6 The Fuel Prices

A base fuel cost case is developed from forecasts of future prices. The natural gas and other fuel prices employed in the LCG database are based on the information supplied by the Department of Energy, NYMEX future contracts, various hub delivery indices and information on fuel availability developed by LCG.

Coal, oil, and nuclear prices have been developed from regional spot forecasts, various external resources and FERC Form 423. Some existing coal and other fuel prices are available from the specifications of long-term purchase contracts. Others are approximated using the fuel costs of plants similar in terms of fuel type, plant type, delivery method, location and size.

1.7 Energy and Ancillary Service Bids

In UPLAN, the supply bids for Energy and Ancillary Services (E&A/S) can be entered in the A/S database module. These bids are used by the UPLAN electricity market model directly to determine the clearing prices using the shadow price for each category of the services. However, in this case, both the supplies bids and demand for these services have to be specified.

The UPLAN procedure starts with a dispatch algorithm to find the clearing price of energy, which requires a detailed representation of the transmission network and associated constraints, as well as regional interface limits. In the absence of such representation, consideration of congestion will be omitted, and the entire system will appear to behave as a single regional energy market, with a single market clearing price, which is contrary to current experience in most markets.

UPLAN Ancillary service model uses Rational Expected Equilibrium Price (REEP) methodology to eliminate the arbitrage between the markets and to determine the bids so that the anticipated profits from any of the several markets must be the same and the opportunity costs maximized. In the following, we describe how the bids that are calculated to achieve this goal for different types of generators.

Hydro-electric Unit Bids

The run-of- river units are must-run units and hence price takers, that is, they bid zero into the market or self-commit. Storage hydro and pumped hydro units bid their marginal revenue over the scheduling period, which is the same as their water value. In UPLAN, the schedulers optimize the total revenues of hydro generators by dispatching the units at the highest revenue (price) period. This is same as bidding the water value of units for the energy market. For the ancillary services market, the A/S bid at any given hour must enable the hydro unit to secure its water value whether it is selected for energy or A/S.

During the charging cycle the pump hydro unit buys energy at the lowest available energy price. However, it can forego its charging cycle (regulation down) if the unit receives its opportunity cost, which is the difference between the discharging revenue and the charging cost. Note that it is the same as the ancillary service bid of the hydro.

Thermal Unit Bids

Generation suppliers using thermal units bid their cost plus the highest A/S service price for which the unit is eligible. The suppliers are indifferent between participation in the A/S market or the energy market, as long as they make the same profit from either one.

To use the thermal unit for regulation up, the unit has to operate at a level lower than the full-load, foregoing the profit potential from running the unit at full-load. Its bid must reflect the value of lost profit in $/MWh for operating the generator at lower than its optimal operating level. To use the thermal unit for regulation down, the unit output can be lowered from the full-load, forgoing the profit potential from running the unit at full load. Its bid must reflect the value of lost profit in $/MWh for operating the generator at lower than its optimal operating level and the cost of ramping down and then up to full load when the unit is no longer used for regulation.

Thermal units used for spinning reserve normally operate at the minimum load level, forgoing the profit potential from running the unit at full load. Bids reflect the value of lost profit in $/MWh for operating the generator at minimum load level and the cost of ramping up to full load when the unit is no longer used for spinning.

1.8 Forward Prices for Energy

The electricity market model begins with the forward (e.g. day-ahead) market protocols to produce the forward price, taking into consideration all the known network line restrictions and area flowgate constraints. This produces an hourly forecast of forward prices for energy and ancillary services for each day of the study period. The energy auction process and determination of prices in the markets with respect to the bidding process is illustrated in Figure below.

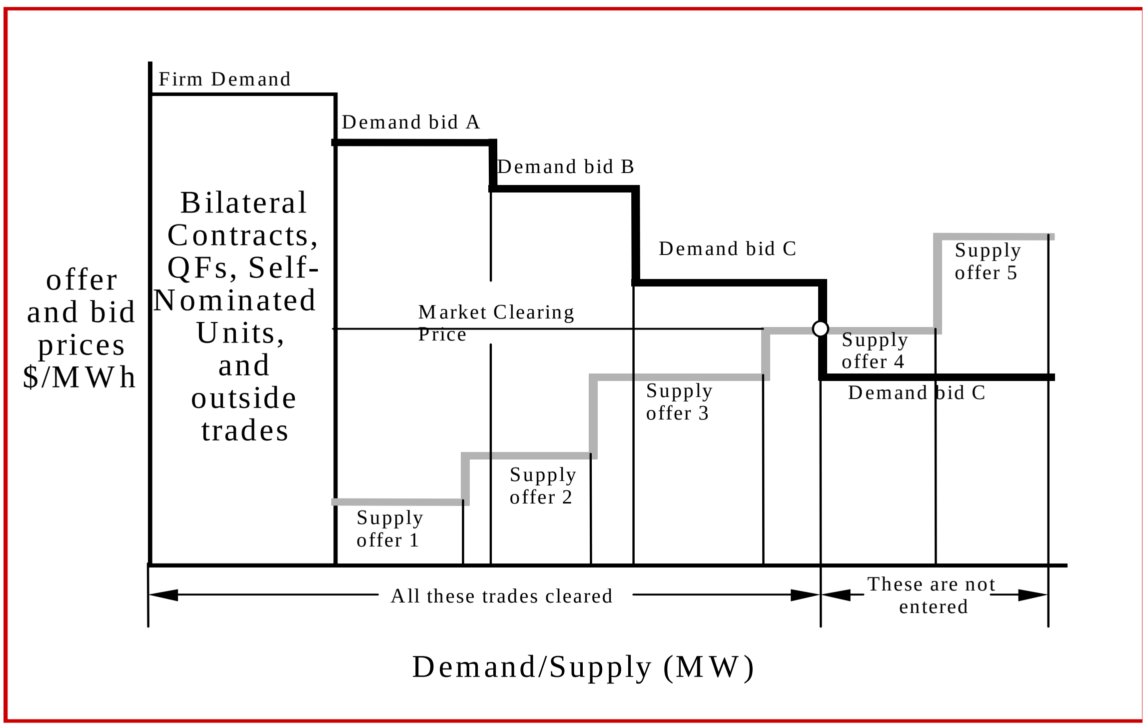


Figure 7. The Competitive Bidding Process

For the purpose of the market evaluation, we divide the entire region of study into sub-regions. Each sub-region represents the natural boundary of a utility or a power exchange where enough generating plants are participating in each hour to maintain an appropriate level of reserves as required by the operating protocol of the sub-region.

Figure below illustrates the procedure for the forward price calculations. A detailed discussion of the dispatch problem can be found in industry publications. The formulation of the problem as shown includes both energy and ancillary service price calculations.

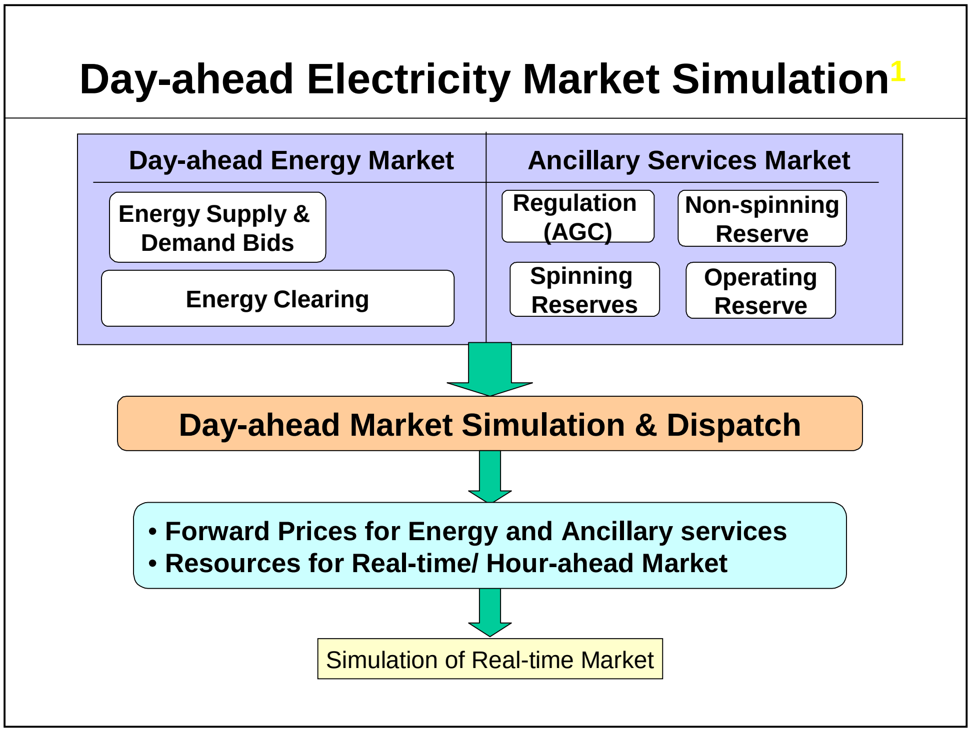


Figure 8. Forward Market Calculation

1.9 Forward Prices for Ancillary Services

In the absence of supply bids for the E&A/S market, UPLAN can internally generate E&A/S bids using REEP methodology which is based on rational bidding behavior of the market participants. The methodology of simulating the A/S market is illustrated in Figure below, which shows how the prices are determined, using large-scale successive linear programming techniques.

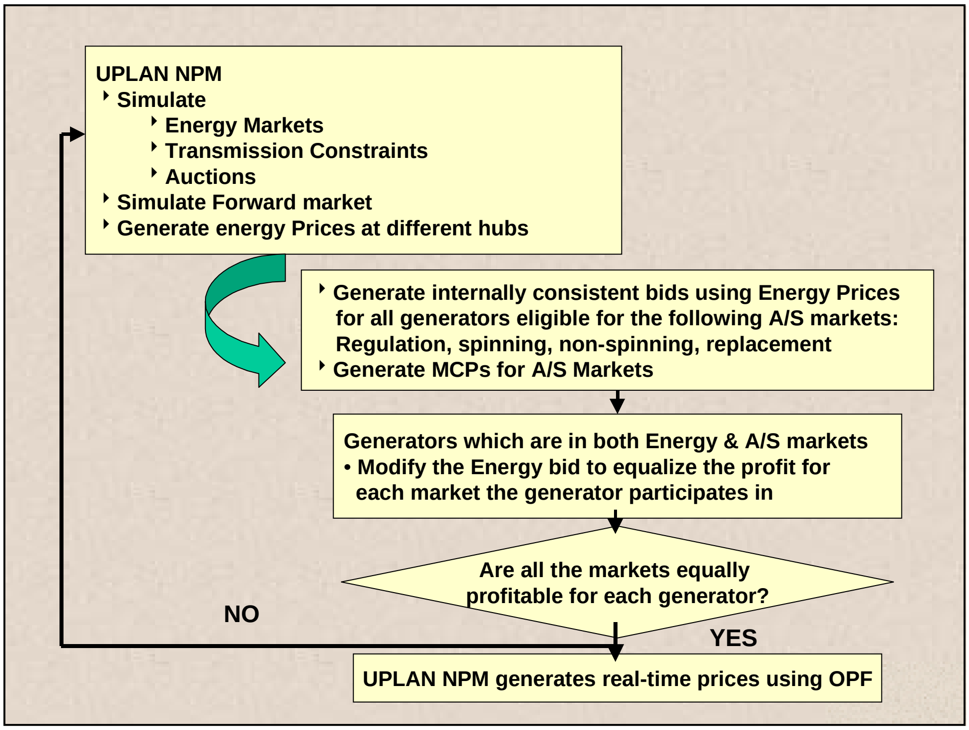


Figure 9. Analysis of Energy and Ancillary Service Market Prices

Due to volatility, participants in the electricity market need to maintain additional reserve capacity to meet the unforeseen events that cause imbalances between supply and demand. Such reserve capacity can be procured at the market price of Ancillary Services (A/S); if this reserve is utilized users pay an additional price for energy. The reserve price is therefore the price of uncertainty.

Most A/S markets are organized into multiple markets in the following order, the energy market being separate from all component A/S markets:

1. Regulation
2. Spinning reserve
3. Non-spinning reserve
4. Replacement or capacity reserve

Both the energy and A/S prices depend on the bidding strategies of the suppliers.

2.0 Real-time Prices of Energy

The real-time, or spot market, serves to establish instantaneous demand-supply equilibrium. All of the generation and demand available through the forward market, A/S market and hour-ahead market is involved in the real-time market. The real-time market provides the market participants an opportunity to balance the demand and supply positions at the spot market prices. In an electrical system, demand and supply must be balanced at every instant, and unforeseen events like high loads, transmission congestion, or forced outages of generating plants, have an immediate impact on the spot prices.

The energy market analysis and the forward market dispatch produce the generation schedule for each of the generators to meet the demand while respecting all regional constraints. However, this solution may not satisfy the requirement of AC load flow and may require substantial modification in the OPF algorithm due to congestion, line outages, and voltage support requirements. The program manages the congestion and security constraints by generator re-dispatch using the AC OPF procedure. This accounts for transmission congestion and utilization of ancillary services and produces the hourly real-time energy imbalance price and the hourly transmission congestion prices.

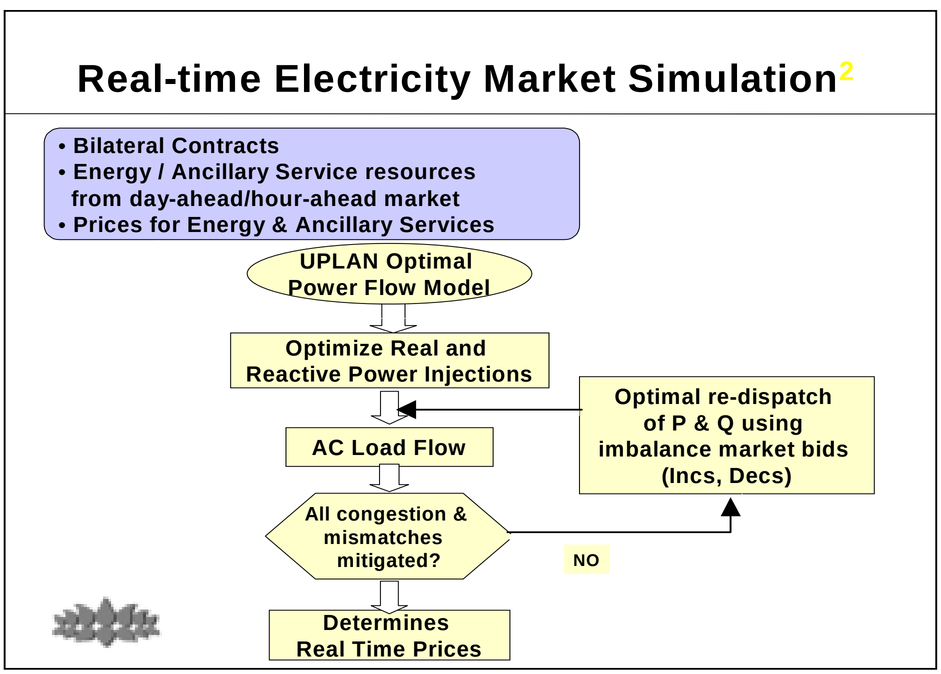


Figure 10. Real Time Market Price Procedure

The units that qualify for the real-time market are those with successful bids in the energy market as well as in the A/S market and those entering through supplemental and hour-ahead bids. The computation of the market clearing price is determined from the imbalance load and the energy bids associated with these A/S units and the bids from supplemental and hour-ahead markets. The OPF procedure and the re-dispatching of the system eliminate the instantaneous imbalance between demand and supply at every electrical bus and manage any transmission congestion that may occur. The resulting nodal and zonal prices are also known as the real-time or ex post facto prices of electricity. UPLAN reports these prices on an hourly basis for each demand and supply node, as well as for each market region, on the basis of the rules of the market.

Merchant plant model The Merchant Plant Addition (MPA) model uses a non-linear decomposition algorithm to determine the timing, location and capacity of new additions. The non-linear optimization program uses the UPLAN-NPM iteratively to search for the optimal addition by estimating the directional derivatives of the decision variables. The MPA essentially performs the following tasks:

- It searches the entire transmission network to determine the nodes where the revenues from the market prices can support new entrants. This set of nodes is used to determine the capacities and technologies which are economically viable.
- The MPA retains all the units which are currently economically viable; for other units which are not economically viable, it attempts to make the units profitable either by improving the efficiency of the unit, improving the emission characteristics, fuel switching, or purchasing emission allowances. If the units are not viable after all the improvements and remain non-competitive with newer units, it retires them or replaces them.
- The MPA model optimizes the timing and capacity of new entrants that meet the investment criteria in terms of rate of return and financial risk.

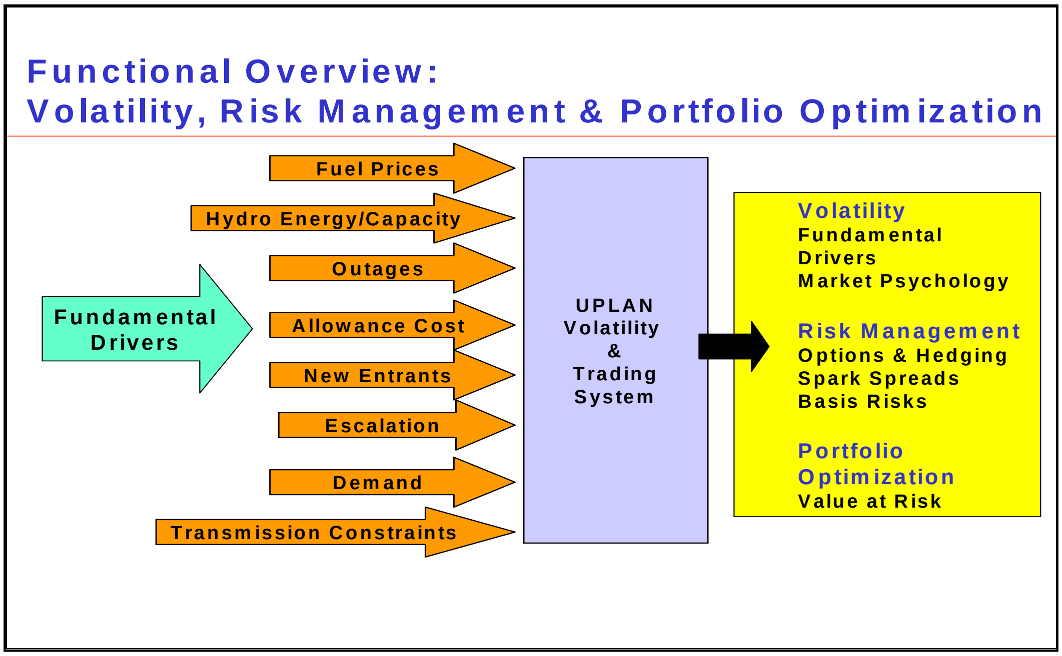
The Merchant Plant Analysis model, along with the determination of emission allowance prices, provides a formidable tool to analyze the impact of current and forthcoming emission regulation on the energy market in general and the existing generation plants in particular.

3.0 The Volatility Model

The prices of electricity vary over a wide range due to many factors, such as an unexpected increase in daily loads, generator outages, transmission congestion or emission constraints. These uncertainties adversely impact market prices, resulting in higher risk for the participants.

The price volatility also influences the revenue earned by the generators, which serve the imbalance market during any time period. Furthermore, if a generator is unable to deliver its output due to constraints, then it has to fulfill its contract obligation by purchasing energy in the spot market. Therefore, an accurate determination of the potential generator profitability requires a through analysis of the spot price volatility.

UPLAN analyzes price volatility based on the probability distribution for each of a series of key drivers. The users can determine the distribution of input variables using historical data. We use beta distribution, which requires the estimation of the maximum, minimum and the most likely value of input variables. To capture the effects of uncertainty, samples are drawn from the distribution of the input variables using Monte Carlo methods and a scenario is created. For each scenario UPLAN is used to simulate the market prices. Running a sufficient number of scenarios then produces a stable distribution of long-term market prices. The volatility indices and all the traditional measures are then developed from the statistical distribution of the variable. The functional overview of the volatility model is displayed below.



In addition to the forward price volatility calculations, the distribution of generator revenues under various outcomes for the drivers is also determined. This provides information relating to the risk associated with participation in the supply market.

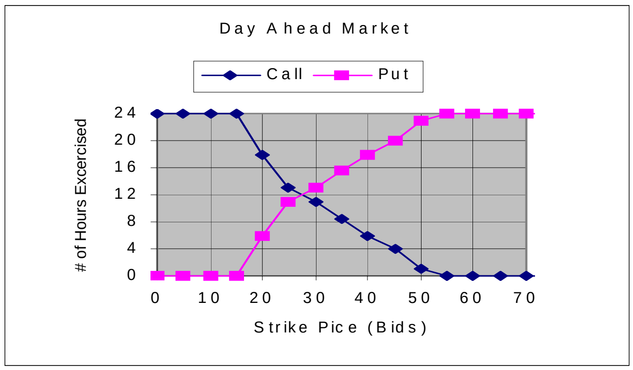
4.0 Running UPLAN Volatility Model

UPLAN's Volatility Model performs systematic evaluation of price volatility due to the uncertainty associated with fundamental drivers such as fuel prices, hydrological conditions, electricity demand, generator and transmission outages, new entrants to the market, and any other critical variables that impact electricity prices. The evaluation is based on Monte Carlo sampling from the probability distribution of the fundamental drivers that contribute to the volatility of energy and ancillary service prices. Some of the output of the model and examples of their uses are described below.

- The probability distribution of prices of energy and each of the ancillary service components are determined.
- Intrinsic and extrinsic values of calls and puts options for energy, A/S and transmission basis differences are reported.
- It provides an alternative calculation of capacity reserve prices as a physical hedge for energy.

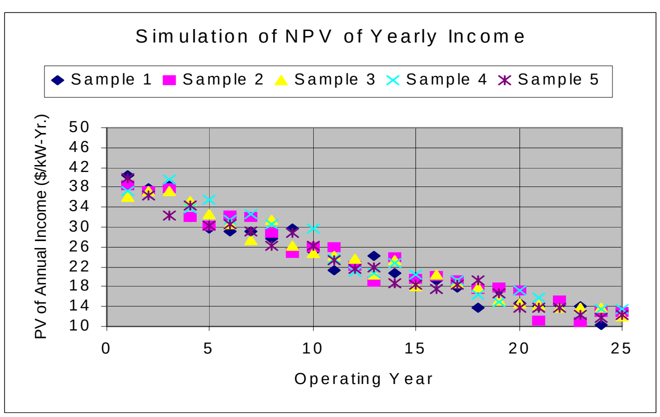
• The buyers’ premium and sellers’ risk across the entire spectrum of strike prices are reported. .

UPLAN Volatility Model produces complete distribution of prices from which the option values are computed. The options curves provide a powerful tool for day-ahead bidding. A similar analysis on a monthly basis provides in-depth insight into the capacity market.



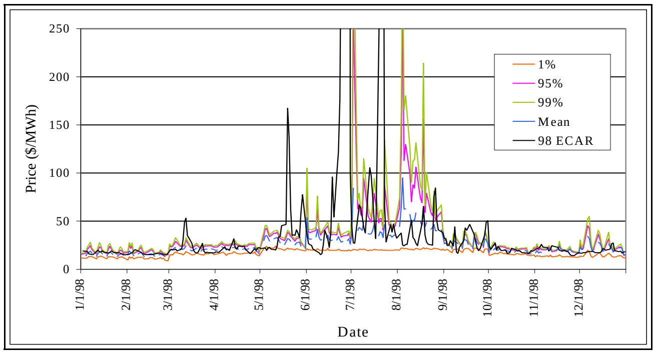
Number of hours a successful bid is exercised in the day-ahead market

Valuation of assets requires calculation of all the revenues the asset can earn from all sources such as energy and ancillary service markets. In addition the volatility of the market, transmission congestion and potential of new merchant plants have substantial impact on the revenues. UPLAN system of models can capture the combined effect of all these factors in an integrated analysis. The figure above displays a few sample paths of net income generated by the UPLAN Volatility Model. The electricity price spikes account for large parts of the revenues of the combustion turbines



Some sample trajectories of net income accrued to new assets simulated by the Volatility Model.

The Merchant Plant model incorporates revenues from price spikes, capacity and operating reserve and trading emission allowances in determining the income of new units.



Daily on-peak price volatility for ECAR

Figure above shows the actual ECAR prices for 1998, along with price distributions obtained from UPLAN's volatility simulation. Note that UPLAN can capture the frequency and duration of the price spikes using the volatility simulation of the structural variables.

The price spikes are rare occurrences and take place when several unusual events occur simultaneously. Point forecasts based on random walks are quite ineffective in identifying these unforeseen events. Although these spikes are infrequent, their contribution to the economic viability of peaking units and the liquidity of the options market is substantial.